Ronald D. Willoughby, PE

Position:	**Executive Consultant**
Years' Experience:	45+
Education:	Honorary Professional Degree of EE – University of Missouri-Rolla (MO Univ. of Science & Tech)(MS&T) Post Graduate Studies – Carnegie-Mellon Univ (CMU) MSEE Power Engineering – Carnegie-Mellon Univ. BSEE – University of Missouri-Rolla (UMR) Professional Engineer (PE) License – Pennsylvania

Key Qualifications:

Distribution Grid Modernization Planning: Systematic/incremental addition of smart grid devices; with technology, performance, and cost central to the planning process.

Renewables Integration and Impact on Utility Grid: Power system analysis/operation, architecture, configurations, distributed generation strategies, market analysis, portfolio analysis, wind power and PV integration.

Conservation Voltage Reduction (CVR): Using smart grid data points and controllable VAR sources to regulate distribution voltages in near real time to reduce demand, lower peaks (kW), and save energy (kWh).

Transmission & Distribution Planning: Power flows; reliability analysis; transient & long-term stability; load shedding; reconfiguration schemes; contingency analysis; root cause analysis; distributed generation; energy storage strategies; protection/coordination; systematic replacement/upgrade strategies; and special protection systems (SPS).

Advanced Protection, Automation & Control: Sensor, communication, sectionalizing, controllable VAR sources, voltage control, expert systems, demand, and energy reduction application strategies.

Distribution Substation Design and Specifications Review: Modular Integrated Transportable Substation (MITS) application, design, specification, and implementation; renewables integration; volt/VAR control; substation upgrades; and distribution automation/protection strategies.

Patents & Publications

Earned U.S. Software Patent 6549880 for *Improving Reliability of Electrical Distribution Networks* (2003).

More than 60 publications relating to electric power systems analysis and operation.

Project Types

Distribution Grid Modernization Planning: Systematic/incremental addition of smart grid devices; with technology, performance, and cost central to the planning process.

Conservation Voltage Reduction (CVR): Using smart grid data points and controllable VAR sources to regulate distribution voltages in near real time to reduce demand, lower peaks (kW), and save energy (kWh).

Renewables Integration: Main substation, collector systems, protection and control.

Power System Energy Use: Technical and non-technical loss evaluation and improvement measures; with specific expertise in island power systems.

Power System Automation: Application of sensor/communication packages, sectionalizing equipment, and SCADA systems to achieve performance targets.

Power System Reliability: Preventive actions and sectionalizing strategies to achieve reliability performance targets.

Power System Protection: Protection/coordination; systematic replacement/upgrade strategies.

Root Cause Analysis (RCA): For unexplained electric power system events.

Knowledge Management: Use cases for technical procedures associated with power system analysis/operation, expert systems, architecture, and configurations.

Project Management: Transmission analysis, distribution analysis, system protection, and reliability improvement.

Training: Power system design, reliability, protection, stability, and operation.

Representative Project Experience

Conservation Voltage Reduction (CVR)

- Project Manager and Technical Lead for Commonwealth Edison Company (ComEd) feasibility study to quantify energy and demand savings using distribution Voltage Optimization techniques. Objectives: 1) Minimize cost by initiating feeder upgrades to achieve minimum performance thresholds. 2) Maximize energy savings by optimizing performance while staying within Total Resource Cost (TRC) constraints.
- Co-Instructor of CVR workshop customized to meet specific ComEd engineering and energy efficiency department needs.
- Co-founder of a CVR Industry Consortium to guide CVR research, work with industry groups, develop policy recommendations, promote implementation strategies, and document the results.
- Technical lead for project commissioned by DOE to conduct a comprehensive study across the USA on CVR, including deployment strategies, costs, benefits, barriers, and potential solutions, through a broad market outreach effort.

Advanced Protection, Automation, & Control for Transmission & Distribution

- Co-Chaired (with the Director of R&D at We-Energies) Distribution Vision 2010 LLC (DV2010), a consortium of Investor Owned Utility (IOU) companies. Mission: To create and execute a roadmap of equipment and service requirements important to cost-effectively operating a reliable electric distribution system; 2002-2006. DV2010 was accountable to CEOs and CFOs of member utilities.
- Led EPC and turnkey solutions in support of electric utility companies for electrical distribution automation, medium voltage modular substations (distribution centers), and wind farm electrical distribution systems (from the base of the turbine towers through interconnection to the utility grid); 1985-1988.
- Invited by the Director of Power & Energy Initiative at the University of Pittsburgh to be an Instructor for a graduate course on Smart Grid Technologies & Applications. Subject: Substation Automation and Protective Relaying; on-going.
- Participated in U.S./Canada Power Outage Task Force led by the Department of Energy (DOE), Natural Resources Canada, and the North American Electric Reliability Council (NERC) created to study the blackout of August 14, 2003, the largest electrical outage event in U.S. history.
- Led comprehensive Root Cause Analysis (RCA) for PJM executive management in response to a July 1999 low voltage condition stemming from record peak loading conditions on the bulk transmission system. Proactive corrective measures prevented future occurrences.

Renewables Integration and Impact on Transmission & Distribution Systems

- Invited by Prime Minister of Curacao to represent USA in 1st Annual Durable Energy Conference in Curacao to address renewables integration issues for the transmission and distribution system; March 2012.
- Invited by CEOs of Wind-2-Power-Systems (W2PS) and Hudson Energy to represent USA for conference in Madrid to cover PV integration, grid integration, energy storage, and DC infrastructure issues; February 2012.
- Invited by CARILEC to chair two sessions on Transforming the Electricity Grid at the Renewable Energy Forum, St Thomas, U.S. Virgin Islands; September 2011. CARILEC represents CEOs, COOs, and CFOs for 33 island utilities in the Caribbean.

Transmission & Distribution Planning

- Led distribution grid modernization planning efforts, focused on systematic and incremental addition of smart grid devices, with technology, performance, and cost central to the planning process
- Led EPC and turnkey solutions for electric distribution automation, medium voltage modular substations (distribution centers), and wind farm distribution systems (from base of turbine towers through interconnection to utility grid). Accountable for success of these focused areas when measured against sales and margin goals, internal and

external budget constraints, and overall customer satisfaction. Routinely augmented internal direct staff with external resources according to project needs. Matrix managed project teams to effectively utilize project resources.

- Co-founder of industry-wide consortium focused on strategic, business, regulatory, and technical issues associated with Conservation Voltage Reduction/Regulation (CVR) at investor-owned utilities, electric cooperatives, and municipals.
- Managed commissioning and public relations for comprehensive distribution line installation in the city of Smolensk, Russia. Project was collaborative effort between U.S. Trade & Development Agency (TDA) and Cooper Power Systems (CPS); 2002-2004.
- Developed distributed CVR measures to conserve energy and reduce overall losses without compromising end-user reliability or power quality.
- Developed emergency generation integration strategies for major industrial complexes in the USA.
- Conducted comprehensive seminar on electric power systems for the Ministry of Water and Power in Peking, China; 1984.
- Performed international power systems studies on power flow, transient stability, shunt compensation, load shedding, motor starting, loss formula development, short circuit, and protective device coordination; 1974-2000. Interfaced with Engineering Planning Managers.
- Led projects sponsored by the Pacific Power Association (PPA) for power system energy analysis and loss reduction on 20 islands in the South Pacific, 10 with U.S.-style power systems, and 10 with European-style power systems. Interfaced directly with CEOs and PPA throughout study.
- Taught Westinghouse Advanced School on Power System Stability; 1980-1988.

Professional Development Activities

NERC Compliance; IEC 61850; DMVP (DMEDI) Process Improvement; Professional Development Seminars on Management (Management Grid, Management Techniques, Team Building); Interpersonal Skills; Time Management; Managing the Software Project; Sales Techniques; SPIN Sales Training; Pricing Strategies; Finances; Technical Writing; Safety; Problem Solving & Decision Making; IEEE Seminars on Relay Coordination and Reactive Power Control; Root Cause Analysis; Reliability Analysis; Intellectual Property; Environmental Compliance; Corporate Ethics; Toastmasters International.

Company Affiliations

Willoughby Consulting, Raleigh, NC (2012 to Present)
Executive Consultant, Electric Power Systems Planning & Operation - Owner

Modular distribution substation application, specification, and implementation. Quantifiable Conservation Voltage Reduction (CVR) assessments for energy efficiency energy savings (kWh) and peak power reduction (kW); CVR application strategies. Emergency backup power supply needs assessment and solution strategies for large industrial/commercial facilities. Portfolio analysis, go-to-market strategies, and operations support related to electric power systems. Specific service areas include transmission and distribution planning, renewables integration strategies, energy efficiency measures, system protection strategies, distribution automation schemes, data management, and business plan development.

River Consulting Group (RCG), Clayton, GA (2018 to Present)
Executive Consultant - Contract
Advisory services related to distribution grid modernization planning efforts involving systematic and incremental addition of smart grid devices, with technology, performance, and cost central to process.

ABB, Inc. (ABB), Raleigh, NC (2016 to 2017)
Executive Consultant - Contract
Advisory services related to distribution grid modernization planning efforts involving systematic and incremental addition of smart grid devices, with technology, performance, and cost central to process.

Advanced Microgrid Solutions (AMS), San Francisco, CA (2015 to 2017)
Executive Consultant - Contract
Advisory services regarding business strategy, competitive intelligence, and energy services pricing strategies related to the company's business development efforts.

Applied Energy Group (AEG), New Brunswick, NJ (2012 to 2015)
Principal, Executive Consultant - Contract
Energy efficiency (savings) analysis methods, project procurement, and project execution. Innovative applications of existing technologies to advance the art. Industry-wide investigations. Direct responsibility for project teams, including subcontractors.

Dell Innovation Services, Peoria, IL (2012 to 2014)
Vice President, Electricity Transmission & Distribution - Contract
Design and apply substations (including modular) for emergency power supply. Develop electrical site one-line diagrams and associated loading profiles. Conduct power demand audits.

KEMA, Raleigh, NC (2006 to 2012)
Vice President, Electricity Transmission & Distribution
Strategic leadership of the U.S. technical T&D practice in North America, focusing on client issues related to electric power system T&D planning, asset management, protection and reliability, advanced technology applications, and future power systems. Direct responsibility for team of 30 professionals.

Cooper Power Systems, Franksville, WI (1989 to 2006)
Director, Industrial Development & Technical Services Marketing; Manager, Systems Integration Solutions; Director, Thomas A. Edison Technical Center; Manager, Systems Engineering Group
Technical solution development for electrical distribution automation, substations, distribution operating centers, and wind farm integration. Accountable for sales, margins, budget, and customer objectives. Directed project teams to matrix manage overall resources (which included marketing, sales, and engineering staffs) to promote services, identify

opportunities, and secure business. Participated in strategic alliances and acquisitions. Managed high power laboratory (500 MVA short circuit generator), high voltage laboratory (2 million volts), and full materials laboratory, with direct responsibility for a team of 110 professionals. Managed group responsible for Modular Integrated Transportable Substation (MITS) application, design, specifications, implementation, and support (69 kV and below) (10 MVA and below).

Westinghouse Advanced Systems Technology, Pittsburgh, PA (1974 to 1988)
Manager, Transmission Planning Section; Manager, T&D Software Services

Responsible for a staff of 8 involved in the application of technical transmission and distribution software, including marketing and customer service.

Black & Veatch Consulting Engineers, Kansas City, MO (1971 to 1974)
Coop student while with the University of Missouri - Rolla

Professional Memberships

- IEEE – Life Senior Member
- IEEE Power Engineering Society – Senior Member
- IEEE Industrial Applications Society – Senior Member
- Phi Kappa Phi – Member
- Eta Kappa Nu – Member
- Tau Beta Pi – Member
- Kappa Kappa Psi – Member
- Wake County NC – Precinct Election Official (2017-2019)

Professional Recognition

2016 Achieved **Life Member** status for the Institute of Electrical and Electronics Engineers (**IEEE**).

2012-14 Invited **Instructor** for **University of Pittsburgh** graduate course on *Smart Grid Technologies & Applications*. Subject: *Substation Automation and Protective Relaying*.

2013 Co-Founder of an industry-wide ***CVR Consortium*** focused on increasing energy savings by resolving strategic, business, and technical issues preventing more wide-spread deployment by electric utility companies.

2012 Earned ***Order of the May*** honors recognition from Carnegie-Mellon University for more than 10 years of continous and consistent support. Citation includes these words: "This special order honors those who embody all the best characteristics for which the society was originally founded in 1947."

2011 Invited **Chairman**, 2 Sessions, *Transforming the Electricity Grid*, **Carilec Renewable Energy Forum**, September 20-21, St. Thomas, U.S. Virgin Islands.

2003 Awarded ***Honorary Professional Degree of Electrical Engineering***, Univ of MO-Rolla (UMR), based on "outstanding professional and personal achievements"

2003 Elected **President**, *Academy of Electrical & Computer Engineers*, UMR

2001 Elected VP, *Academy of Electrical & Computer Engineers*, University of Missouri-Rolla

2001 Co-Chair, Steering Committee to develop **Distribution Vision 2010 LLC (DV2010)**, consortium of Investor Owned Utility (IOU) companies

2001 Appointed **Chairman**, Technical Paper Committee, USA National Committee, **CIRED**

2000 Appointed to ***Industry Advisory Council***, Rensselaer Polytechnic Institute (RPI), NY

1998 Appointed to ***Industrial Liason Council (ILC)*** for the College of Engineering and Applied Science, University of Wisconsin-Milwaukee

1997 Elected to ***Academy of Electrical & Computer Engineers***, University of Missouri-Rolla for "outstanding contributions to the profession of electrical engineering and for leadership in the community and profession." Requires minimum 20 years experience to qualify.

1991 Selected for **USA Trade Mission** on Electric Power to East Germany. Represented USA distribution equipment technologies. [E & W Berlin concrete wall fell Nov 1989]

1989 Appointed to ***Industry Advisory Council***, University of Missouri-Rolla (UMR).

1985 *Westinghouse* ***Engineering Achievement Award*** for "high level technical contribution to the development and implementation of profitable engineering courses in the Electric Utility and Industrial markets."

1985 ***Senior Member*** status for Institute of Electrical & Electronics Engineers (**IEEE**).

1984 Elected *Chairman* of the <u>only</u> **Quality Circle** in operation at Westinghouse Advanced Systems Technology (AST)

1982 Appointed to <u>first</u> ***Engineering Advisory Council*** for Westinghouse AST

1978 Earned ***PROFESSIONAL ENGINEER (PE) License*** from the Commonwealth of Pennsylvania

1972 Received *Outstanding Bandsman* award from Kappa Kappa Psi band fraternity

1969 **Valedictorian** and **Student Council President**, Grandview Senior High School

Publications

Ronald Dean Willoughby, PE

Willoughby, Ronald D, Bob Grant, and George Fandos. "Unbiased 360-Degree DER Evaluations and Assistance," EnergyCentral - Utility Professionals Group, April 20, 2020.

Willoughby, Ronald D. "Why Do It?," *EnergyPulse* from Energy Central – Intelligent Utility, March 21, 2018.

Willoughby, R., S. K. Gill, E, Zhang, J. Silvers. "Distributed Energy Resources Supporting Power Grid Reliability," CIGRE US National Committee, 2016 Grid of the Future Symposium, November 2016.

Willoughby, Ronald D. "Grid Modernization is Like Remodeling a House," Energy Central - Electric Power Systems Planning & Operation, July 20, 2016.

Willoughby, Ronald D. "The Power of Incrementalism," *EnergyPulse* from Energy Central - Communications & Security, February 10, 2016.

Willoughby, Ronald D. "Aging Workforce Presents Knowledge Management Opportunities," *EnergyPulse* from Energy Central - Human Resources, November 13, 2015.

Willoughby, Ronald D. "SEPB CVR Proposal Response Review," Report for AEG for TVA on behalf of SEPB, PO 916082, June 8, 2015.

Willoughby, Ronald D. "Distribution Automation and Conservation Voltage Reduction," *EnergyPulse* from Energy Central - Grid Operations; April 17, 2015.

Willoughby, Ronald D. "CVR Fundamentals," White Paper, January 5, 2015.

Willoughby, Ronald D., et al. "Final Report - Voltage Optimization (VO) Feasibility Study," AEG for ComEd VO Study, Contract No. 01146430, January 6, 2015.

Willoughby, Ronald D. "Order of the 9's," *EnergyPulse* from Energy Central - Grid Operations, June 2, 2014.

Willoughby, Ronald D. "Analysis Paralysis," *EnergyPulse* from Energy Central - Business Corporate, January 16, 2014.

Willoughby, Ronald D. "CVR and the Lost Revenue Conundrum," *EnergyPulse* from Energy Central, August 9, 2013.

Willoughby, Ronald D. "Time to Take a Second Look at Conservation Voltage Regulation?" *Intelligent Utility Update*, June 4, 2013.

Willoughby, Ron, Kellogg Warner. "Voltage Management: A Hidden Energy Efficiency Resource," GTM Research *Energy Efficiency Newsletter*, May 7, 2013.

Willoughby, Ron, Kellogg Warner. “Conservation Voltage Regulation: An Energy Efficiency Resource,” IEEE *Smart Grid Newsletter*, April 10, 2013.

Willoughby, Ronald D. “Thinking Through Grid Modernization: It’s a Chinese Puzzle – Moving Each Piece Moves Another,” article written by Phil Carson of *Intelligent Utility Daily* after an exclusive interview with Mr. Willoughby, June 17, 2012.

Willoughby, Ronald D. “Power System Automation Drives Need for Data Acquisition,” *Distributed Energy* Magazine, April 2012.

Willoughby, Ronald D. and Juan Gers. “IEC 61850 Primer,” DNV KEMA *TECH Notes*, April 2012.

Willoughby, Ronald D. “Power System Automation Drives the Need for Smart Grid,” DNV KEMA *Sherpa* Web Site, December 1, 2011.

Willoughby, Ronald D. “System Automation Drives Need for Data Acquisition,” *Electric Light & Power* Magazine, November 2011.

Willoughby, Ronald D. “System Automation Drives Need for Data Acquisition,” *PowerGrid International* Magazine, September 2011, pp 52-56.

Willoughby, Ronald D. “The ‘Next Big Thing,’” article written by Phil Carson of *Intelligent Utility Daily* after an exclusive interview with Mr. Willoughby, April 21, 2010.

Willoughby, R. D., S. French Smith, S. Varadan. “A Knowledge Framework for Sustaining Business Growth and Success,” Panel Session Submission 2010TD0574, IEEE T&D World Conference & Exposition, April 2010, New Orleans.

Willoughby, R. D. (Contributing Expert). *Utility of the Future*, Volume 2, *The Promise of Energy Storage*, KEMA, December 2009.

Willoughby, R. D. “The Evolving Convergence of Distribution Automation and Advanced Metering Infrastructure,” KEMA Automation Insight, June 2007.

Willoughby, R. D. and L. A. Kojovic. “Integration of Distributed Generation In A Typical USA Distribution System,” CIRED 2001, Amsterdam Netherlands, June 2001.

Willoughby, R. D. “Order of the 9’s,” Cooper Power Systems *SETUP* Newsletter, Summer 2000 Edition.

Willoughby, R. D., P. Avery, et al. “Economic Solutions To Power Quality and Reliability Problems,” American Power Conference *Proceedings*, Chicago, IL, April 10-12, 2000.

Willoughby, R. D. and L. A. Kojovic. “Digital Models Simulate Physical Test Facilities,” *IEEE Computer Applications in Power* Magazine, April 1995.

Willoughby, R. D., C. A. McCarthy, et al. “Power Quality and Reliability Services,” Electric Power '99 Conference *Proceedings*, Baltimore MD, April 1999.

Willoughby, R. D., C. Gilker, and E. Strauss. “Education Highway for the Practicing Engineer: What Next in the Age of Deregulation?” Systems Engineering Group Bulletin SE9901, February 1999.

Willoughby, R. D. and S. R. Mendis. "Harmonic Filters Provide The Key To Plant Reliability," PPE Magazine, April 1996.

Willoughby, R. D. and L. A. Kojovic. "Computer Methods for Simulations of Power Lab Tests & Electrical Apparatus Operations in Power Systems," TESLA II Millennium, Belgrade, Yugoslavia, October 1996.

Willoughby, R. D., C. Gilker, et al. "Training for TODAY'S Practicing Electrical Distribution Engineer," Systems Engineering Group Bulletin SE9402, Cooper Power Systems, August 1994.

Willoughby, R. D. and K. Argiropoulos. "Hybrid Surge Arrester Technology," US Technology for the Production, Transmission, & Distribution of Electric Power Seminar, Berlin, Germany, October 1991.

Willoughby, R. D. and K. Argiropoulos. "Overcurrent Protection Devices for Overhead Distribution Systems," US Technology for the Production, Transmission, & Distribution of Electric Power Seminar, Berlin, Germany, October 1991.

Willoughby, R. D. and K. Argiropoulos. "Voltage Regulation Equipment for Overhead Distribution Systems," US Technology for the Production, Transmission, & Distribution of Electric Power Seminar, Berlin, Germany, October 1991.

Willoughby, R. D. and S. R. Mendis. "Power Quality Problems in Electric Power Systems," US Technology for the Production, Transmission, & Distribution of Electric Power Seminar, Berlin, Germany, October 1991.

Willoughby, R. D., et al. "Electrical Studies for an industrial Gas Turbine Co-Generation Facility," IEEE Industrial Applications Society (IAS) *Transactions*, July/August 1989.

Willoughby, R. D., R. W. Johnson, and R. A. Whiteside. "Computer-Aided Protective Device Coordination: Advantages," Congress on Protective Systsems for Electrical Installation, Puerto la Cruz, VZ, July 29-31, 1987.

Willoughby, R. D. , et al. "A Key to Plant Reliability: System Studies," Pakistan Electrical Conference, February 1987.

Willoughby, R. D., and S. Rubino. "Power Systems Studies can P4redict and Resolve Harmonic Resonance Problems in Industrial Planrs," IEEE Petroleum and Chemical (PCIC) *Conference Record*, September 1985.

Willoughby, R. D., J. A. Juves, and A. Batenburg. "Utility Survey of Methods for Minimizing the Number and Severity of System Separations," *Final Report*, Electric Power Research Institute, EPRI EL-3437, Project 1952-1, March 1984.

Willoughby, R. D. "Limitations on Local Shunt Compensation Studied with WESTCAT™," the Westinghouse *AST/Group News*, Pittsburgh, Pennsylvania, Winter 1983/84.

Willoughby, R. D. "New Program for Modelling Induction Motors," the Westinghouse *AST/Group News*, Pittsburgh, Pennsylvania, Summer 1983.

Willoughby, R. D. and J. A. Juves. "Computer Software for the Analysis of Industrial Power Systems," Westinghouse Industrial Applications *Workshop Proceedings*, Philadelphia, Pennsylvania, April 19-20, 1983.

Willoughby, R. D., J. A. Juves and S. S. Waters. "A Streamlined Procedure fro Obtaining Regulatory Approval for New Transmission Lines," *Final Report*, Electric Power Research Institute, EPRI EL-1404, Contract TPS-733, December 1982.

Willoughby, R. D., R. W. Powell, and T. E. Szabo. "The Effects of Shunt Compensation on Local Generation Requirements," Fourth (4th) Conference on Electric Power Supply Industry *Proceedings*, Bangkok, Thailand, 1982.

Willoughby, R. D. and S. S. Waters. "Modeling Induction Motors for System Studies," IEEE Industrial Applications Society (IAS) *Transactions*, San Francisco, California, 1982.

Willoughby, R. D. and P. M. Myers. "Special Industrial System Studies to Insure Plant Reliability," IEEE Petroleum and Chemical (PCIC) *Conference Record*, St. Louis, Missouri, 1982.

Willoughby, R. D. and J. A. Juves. "Justification and Approval of New Electric Transmission Lines: A Procedure," *Workshop Proceedings*, Electric Power Research Institute, EPRI EL-2190, Contract WS 79-230, December 1981, Section 1.

Willoughby, R. D. and S. S. Waters. "Procedure for Conducting a Transient Stability Study," IEEE Midwest Power Symposium *Conference Record*, University of Illinois, October 1981.

Willoughby, R. D. and E. R. Taylor, Jr.. "Practical Application Limit for Shunt Compensation Before Generation Addition," Pennsylvania Electric Association (PEA) Biannual System Planning Committee Meeting *Record*, Hershey, Pennsylvania, September 1981.

Willoughby, R. D., R. S. Hahn, S. Dasgupta, and E. M. Baytch. "Maximum Frequency Decay Rate for Reactor Coolant Pump Motors," IEEE *Transactions* on Nuclear Science, Vol NS-26, No. 1, February 1979, pp. 863-870.

Willoughby, R. D. and R. W. Johnson. "Stability Study Commentary and Interpretation of Computer Printout for Sonatrach LNG Plant Electrical Power System," *Final Report*, Report No. AST-75-1000-08, Westinghouse Advanced Systems Technology, Pittsburgh, Pennsylvania, June 1975.

Willoughby, R. D. and J. W. Skooglund. "Transient Stability Study for Central Nuclear de Almaraz," *Final Report*, Report No. AST-75-1023, Westinghouse Advanced Systems Technology, Pittsburgh, Pennsylvania, May 1975.

Willoughby, R. D. and R. W. Johnson. "Load Flow Study Commentary and Interpretation of Computer Printout for Sonotrach LNG Plant Electrical Power System," *Final Report*, Report No. AST-75-1000-06, Westinghouse Advanced Systems Technology, Pittsburgh, Pennsylvania, April 1975.

Willoughby, R. D. and R. W. Johnson. "Protective Device Coordination Study Commentary and Interpretation of Computer Printout for Sonotrach LNG Plant Electrical Power System," *Final Report*, Report No. AST-75-1000-04, Westinghouse Advanced Systems Technology, Pittsburgh, Pennsylvania, March 1975.

Willoughby, R. D. and R. W. Johnson. "Short Circuit Study Commentary and Interpretation of Computer Printout for Sonotrach LNG Plant Electrical Power System," *Final Report*, Report No. AST-75-1000-02, Westinghouse Advanced Systems Technology, Pittsburgh, Pennsylvania, February 1975.

Joseph J. DeVirgilio, Jr. Owner, Suncoast Management Consultants, LLC

Education:

B.E./1973/Electrical Engineering/Stevens Institute of Technology, Hoboken, NJ

M.E./1981/ Electric Power Engineering/RPI, Troy, NY

Professional Experience:

2013 – Present	Sarasota Memorial Healthcare System: Board member, former Chairman
2011 - Present	Suncoast Management Consultants, LLC: Owner
2010	United Way of Dutchess County: CEO
1973 - 2010	CH ENERGY GROUP, INC. CENTRAL HUDSON GAS & ELECTRIC CORPORATION CENTRAL HUDSON ENTERPRISES CORPORATION (CHEC) 284 South Avenue, Poughkeepsie, NY 12601
1/05 -12/10	Executive Vice President - Corporate Services and Administration Senior Corporate Officer and member of the Executive Team of CH Energy Group, Inc. Director of Central Hudson Gas & Electric Corp ("Central Hudson") and Central Hudson Enterprises Corp ("CHEC") Executive Responsibility for Griffith Energy Services, Inc., a wholly-owned fuel oil distribution subsidiary. Executive responsible for establishing and executing corporate policy and objectives and associated implementation of the related processes for the following areas of responsibility for Central Hudson: Information Technology; Corporate Communications, Media Relations, Governmental Affairs, and Economic Development; Human Resources Purchasing & Stores; Fleet Management; Office Services; Facility Operation & Maintenance; and Corporate Quality and Process Re-engineering. Corporate Executive Committee membership: Chairperson: I/T Steering Committee. Member of the Capital Resource Allocation Committee.
03/05 -12/10	Director, Central Hudson Gas & Electric Corp

03/02 -12/10	Director and Executive Vice President – CHEC, Griffith Energy Services and SCASCO
11/98 -12/24	Senior Vice President - Corporate Services and Administration Corporate Executive Committee membership: Chairperson: I/T Steering Committee and the Retirement Income, 401K, and VEBA Plans Administrative Committees. Member of the Capital Resource Committee.
5/88 -11/98	Vice President -- Human Resources and Administration
4/86 - 5/88	Assistant Vice President – Gas & Electric Customer Services & T&D Operation
3/84 - 4/86	Manager – Corporate Services & I/T
3/82 - 3/84	Manager – Gas & Electric Customer Services Field and Call Center Operation
3/79 - 3/82	District Superintendent – Catskill Gas & Electric T&D Operation
6/73 - 3/79	Engineering Assignments – Gas and Electric Field Engineering, Gas Meter Engineer, and Gas Testing facility supervisor

Professional Affiliations:

3/80 – 12/11	Professional Engineer, New York State, License No. 057637
1994 - 2000	Marketing Executives Conference -- member 1994; Executive Committee 1995; Program Chairperson 1997.
1993 -2004	Council of Industry of Southeastern New York -- Board of Directors.
1988 -1999	New York State Regional Utility Group -- Central Hudson's Representative
1982-1998	American Gas Association (AGA) -- Central Hudson Gas & Electric's Representative; Customer Services Committee (1982-1988); Human Resources Committee (1988 to 1998).

STATE OF NEW HAMPSHIRE

Department of Energy
Intra-Department Communication

DATE: October 25, 2023

FROM: Enforcement Division Audit Staff

SUBJECT: Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
DE 23-039 – Test Year 12/31/2022
FINAL Audit Report

TO: Tom Frantz, Director, Regulatory
Elizabeth Nixon, Director Electric, Regulatory
Scott Balise, Utility Analyst, Regulatory
Jay Dudley, Utility Analyst, Regulatory
Steve Eckberg, Utility Analyst, Regulatory
Heidi Lemay, Utility Analyst, Regulatory
Mark Toscano, Utility Analyst, Regulatory
Jaqueline Trottier, Utility Analyst, Regulatory
Alexandra Ladwig, Staff Attorney

Introduction

On March 29, 2023, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (GSE, Company) filed a notice of intent to file rate schedules. The noticed rate filing schedules were provided to the Public Utilities Commission and the Department of Energy on April 28, 2023. The Department of Energy filed a motion to dismiss the rate filing on the same day, due to the lack of a 2022 FERC Form 1. The PUC granted the motion via Order 26,814, May 2, 2023, which dismissed the filing without prejudice, but allowed the docket to remain open.

Liberty filed the calendar year 2022 FERC Form 1 on May 5, 2023, the same day that a complete rate case filing was submitted to the PUC.

The audit work began on May 26, 2023. While Audit appreciates the help of Liberty's Regulatory and Accounting staff, we were unable to efficiently complete our work due to the significant timing delays between asking questions of Liberty and receiving responses. Over the course of the audit, we asked 115 specific questions. Complete responses took from one week to five weeks for the Company to provide.

One question relating to a tariff test (refer to the *Revenue* portion of this report) was originally asked on July 25, 2023, and was completely answered October 10, 2023, 77 days after the initial documentation request.

Audit is aware of the hundreds of data requests that were issued to Liberty throughout the course of the audit timeframe. Audit indicated to Liberty that if any question asked by Audit had been addressed in a data response, the Company could simply direct the Audit staff to that response. However, questions posed during the course of an audit are specific and detailed relating to actual accounting entries, verification of adherence to prior PUC Orders, settlement agreements, FERC uniform system of accounts, internal Company procedure manuals, etc. As a result, most of the audit work had questions outside of the scope of various data requests. However, because data requests have a required time in which to respond, often the Audit requests were last to be answered. Audit believes that the formality of responding to Audit requests lead, in part, to the delay in answering questions. This hindered our ability to complete the audit work efficiently and effectively.

Orders

Order 26,829 issued May 26, 2023 in docket DE 23-039, among other things, provided notice of the rate case adjudicative proceeding, set dates for the presentation of the rate filing and a prehearing conference, included details regarding intervention, public notice, and requiring Liberty to file all rate schedules in live Excel format with all supporting workpapers.

Order 26,849 issued June 15, 2023 in dockets DE 23-039 and DE 17-189 approved reviewing all issues related to the ongoing implementation of Liberty's battery storage pilot program initially docketed as DE 17-189.

Order 26,537 issued October 29, 2021 in docket DE 19-064 approved recovery of the 2020 investments in the Battery Pilot Program.

Base rates in effect during the test year were approved in docket DE 19-064 via Order 26,005, based on a 12/31/2018 test year. Three step adjustments were approved in the Settlement, based on assets in service as of 12/31/2019, 2020, and 2021.

Corporate Structure

As outlined within the 2022 FERC Form 1, and the 2021 FERC Form 1 page 102, the corporate structure of Liberty Utilities (Granite State Electric) Corp. a New Hampshire corporation, is:
100% owned by
Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation which is 100% owned by
Liberty Utilities Co., a Delaware corporation which is 100% owned by
Liberty Utilities (America) Holdco, Inc., a Delaware corporation which is 100% owned by
Liberty Utilities (America) Holdings, LLC, a Delaware limited liability corporation which is 100% owned by
Liberty Utilities (America) Co., a Delaware corporation which is 15.055% owned by Algonquin Power & Utilities Corporation and 84.945% owned by
Liberty Utilities (Canada) Corp., a Canada corporation which is 100% owned by
Algonquin Power & Utilities Corp., a Canada corporation which is publicly traded.

According to the FERC Form 1 for the year ended 12/31/2020, the structure reflected one ownership line differently than what is outlined above: Liberty Utilities (America) Co. was 100% owned by Liberty Utilities (Canada) Corp. Audit requested general clarification of the change, and was told: "*Liberty Utilities (Canada) Corp. is 100% directly owned by Algonquin Power & Utilities Corp. ("APUC"). Given APUC is the ultimate parent entity in the group that raises debt and equity financing to fund its various subsidiaries, APUC made direct contributions to Liberty Utilities (America) Co. to ease the additional administrative burdens associated with moving funds through the ownership chain. The change in ownership structure as stated in the Company's FERC Form 1 reflects this contribution by APUC to Liberty Utilities (America) Co.*"

Management and Structure

Liberty provides the Commission with a quarterly organizational chart, in compliance with the Commission Order 25,370 issued in the EnergyNorth docket DG11-040. Audit has reviewed the FERC Form 1 annual reports from 2012 through 2022, and notes the following with respect to the position of NH President, which has changed as follows:

President – V. DelVecchio July 2012 – December 31, 2013
President – R. Leehr January 1, 2014 – July 31, 2014
President – D. Saad August 1, 2014 – September 23, 2015
President – D. Swain September 23, 2015 – December 31, 2016
President – J. Sweeney January 1, 2017 – September 4, 2017
President – S. Fleck September 15, 2017 – June 30, 2021
President – N. Proudman June 30, 2021 - current

Affiliate Service Agreements

During the test year, the workforce in New Hampshire, for both GSE and EnergyNorth Natural Gas (ENG), were direct employees of Liberty Utilities Services Company (LUSC). Refer to the Payroll portion of this report.

A money-pool agreement was proposed by the Company, reviewed by Commission Staff, and approved by the Commission, via Secretarial Letter in docket DA 17-188. A revision to that agreement was provided to Audit. The First Amendment to Money Pool Agreement was effective 8/24/2020, between Liberty Utilities Co. (LUCo) and:

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Liberty Utilities (Granite State Electric) Corp.
Liberty Utilities (New England Natural Gas) Corp.
Liberty Utilities (Peach State Natural Gas) Corp.
Liberty Utilities (Pine Bluff Water) Corp.
And other direct and indirect subsidiaries or affiliates of LUCo

The agreement specifies that the "*daily outstanding balance of funds contributed to and lent through the Money Pool will earn interest…and bear interest at the daily average interest rate paid for funds obtained by LUCo from its commercial paper program…*"

The Amendment was filed in docket DA 17-188 on December 31, 2020, outside of the required 10 days per RSA 366:3. The Company requested approved (pursuant to RSA 366:4). The docket does not reflect any further action by the PUC.

Cost Allocation Manual (CAM)

As outlined in the CAM, version 2017, effective January 1, 2017, costs incurred at the APUC level are directly charged if possible. Costs at the Algonquin Power & Utilities Corp. (APUC) level include financial and strategic management, access to capital, corporate governance, and administration. Those costs are allocated among Liberty Power (generating facilities) and Liberty Utilities, both regulated utilities directly and Liberty Utilities Service Corp.

Algonquin Power & Utilities Corp (APUC)

Allocation methodologies applied to the specified indirect costs are allocated at noted percentages based on the types of costs identified:

Table 1 of the APUC Summary of Corporate Allocation Method of APUC Indirect Costs:

Type of Cost	# of Employees	Net Plant	O&M	Revenue
Legal	33%	33%	33%	not applicable
Tax Services		33%	33%	33%
Audit		33%	33%	33%
Investor Relations		33%	33%	33%
Director Fees/Insurance		33%	33%	33%
Licenses, Fees, Permits		33%	33%	33%
Escrow and Transfer Agent Fees		33%	33%	33%
Other Professional Services		33%	33%	33%

Other Administration Costs	50% Oakville Employees	50% Total Employees
Executive and Strategic Management	50% Oakville Employees	50% Total Employees

Liberty Utilities (Canada) Corp. (LUC)

Costs at the LUC level include executive, regulatory strategy, energy, page procurement, operations, utility planning, administration, and customer experience. Costs at this level provide standardization across the Liberty Utilities' regulated companies, and are allocated based on a four factor allocation. The factors are customer count 40%, utility net plant 20%, non-labor expenses 20% and labor expenses 20%.

During the test year, the (rounded) factors were:

	4/2022 – 3/2023
Liberty Water (AZ)	05.88%
Liberty Water (TX)	00.86%
Calpeco	06.46%
Granite State	**04.40%**
EnergyNorth	**09.72%**
Midstates Gas	06.04%
Midstates Water	00.72%
Arkansas	01.46%

Woodson Hensley	00.04%
Georgia	04.71%
New England Gas	05.15%
Whitehall-Water	00.14%
Whitehall-Sewer	00.15%
Parkwater	04.52%
Empire	34.65%
New Brunswick Gas	01.99%
St. Lawrence Gas	02.06%
Tinker Transmission	00.09%
New York Water	10.96%
	100.0%

Overhead/Burden Rate

Audit requested the overhead/burden rate in place for the test year and was provided with the methodology, based on budgets for 2022. The rates were calculated for January 2022:

Service Billings	**2022 Budgeted Costs**	**2022**	**% of Total**	**% of Payroll**	**Source File**
X	Rent	403,188	1.03%	0.01	2022 Clarity Budget and Lease
X	IT-related costs	3,579,924	9.18%	0.11	2022 Clarity Budget
X	IT Software Depreciation	1,077,798	2.76%	0.03	2022 IT software calculation
X	Property insurance and injuries and damages	4,396,680	11.27%	0.14	2022 Budget
X	Pensions/OPEB (all costs) and Benefits	12,187,441	31.25%	0.38	2022 Budget and actuarial data
X	TNW	4,674,864	11.99%	0.15	2022 Payroll File and Budget Submissions
X	Incentive Awards @ target	3,052,711	7.83%	0.10	2022 Budget Template
X	Payroll Taxes	2,995,757	7.68%	0.09	2022 Budget
X	Back Office: Labor	2,542,288	6.52%	0.08	2022 Budget Template
X	Finance: Non-Labor	344,828	0.88%	0.01	2022 Budget
X	HR: Non-Labor	279,271	0.72%	0.01	2022 Budget
X	Regulatory: Non-Labor	133,447	0.34%	0.00	2022 Budget
X	Legal: Non-Labor	77,370	0.20%	0.00	2022 Budget
X	Executive: Non-Labor	165,210	0.42%	0.01	2022 Budget
X	EHS: Non-Labor	314,492	0.81%	0.01	2022 Budget
X	Procurement: Non-Labor	1,516,218	3.89%	0.05	2022 Budget
X	Electric Ops: Non-Labor	84,200	0.22%	0.00	2022 Budget
X	Gas Ops: Non-labor	93,329	0.24%	0.00	2022 Budget
X	Dispatch, Control & Production: Non-labor	471,659	1.21%	0.01	2022 Budget
X	Engineering: Non-labor	611,403	1.57%	0.02	2022 Budget
	Total Costs	39,002,079	100.00%	1.2236	
	Total 2022 Budgeted payroll (Excludes Incentives/TNW/Back Office Labor)	31,873,988			
	Overhead/Burden For Service Billings - 8810	122.4%			

The burden calculation is then split between GSE and ENG:

	GSE 30%		ENG 70%	
X	89,553	0.8%	313,635	1.5%
X	1,261,898	11.2%	2,318,027	11.2%
X	360,253	3.2%	717,544	3.5%
X	2,646,531	23.5%	1,750,149	8.5%
X	4,510,070	40.1%	7,677,371	37.2%
X	1,402,459	12.5%	3,272,404	15.9%
X	915,813	8.1%	2,136,898	10.4%
X	898,727	8.0%	2,097,030	10.2%
X	958,351	8.5%	1,583,937	7.7%
X	103,549	0.9%	241,280	1.2%
X	85,460	0.8%	193,810	0.9%
X	41,088	0.4%	92,359	0.4%
X	23,826	0.2%	53,544	0.3%
X	26,451	0.2%	138,759	0.7%
X	97,855	0.9%	216,637	1.1%
X	614,521	5.5%	901,697	4.4%
X	84,200	0.7%	-	0.0%
X	-	0.0%	93,329	0.5%
X	74,084	0.7%	397,575	1.9%
X	311,969	2.8%	299,434	1.5%
	14,506,660	128.9%	24,495,419	118.8%
Total 2022 Budgeted payroll (Excludes Bonuses and other Burden Labor)	11,252,644.48		20,622,336.71	
Burden Rates	**GSE Burden 128.92%**		**ENG Burden 118.78%**	

<u>Liberty Utilities Regional</u>

Costs at the LU Regional level are allocated based on a four factor allocation. The factors are net plant 25%, customer count 25%, expenses 25%, and labor 25%. During the test year, the (rounded) factors were:

	4/2022 – 3/2023
Liberty Water (AZ)	05.19%
Liberty Water (TX)	00.83%
Calpeco	06.74%
Granite State	**04.30%**
EnergyNorth	**09.60%**
Midstates Gas	05.40%
Midstates Water	00.67%
Arkansas	01.33%
Woodson Hensley	00.03%
Georgia	04.24%
New England Gas	04.90%
Whitehall-Water	00.13%
Whitehall-Sewer	00.14%
Parkwater	04.33%
Empire	37.47%
New Brunswick Gas	02.17%
St. Lawrence Gas	02.10%
Tinker Transmission	00.11%
New York Water	10.34%
	100.02%

Corporate Internal Audit

Audit requested the Algonquin Internal Audit staff report or opinion relative to the calculation of overheads. The Company indicated that the Internal Audit staff, as well as the External auditors, review the calculations, but do not issue reports or opinions exclusively related to overheads.

External Audits

The Company included financial audit results for the years ending 12/31/2021 and 12/31/2022 as conducted by Ernst and Young, within the filing Puc1604.01(a)(13), Bates pages I-113 through I-136.

Customer Information System and General Ledger

Effective October 1, 2022, the Company converted from the Great Plains (GP) software system to SAP and Power Plan. The change impacted all aspects of the utility's business, from customer service, to accounting for Plant through use of Power Plan, to recording of financial entries in its general ledger. Audit verified the roll-forward of the September 30, 2022 account balances within each GP general ledger account into the SAP system.

Audit was informed that the functionality of SAP is:

"*The job system in SAP is known as WBS elements (Work Breakdown Structure). These are used to record and track expenses to specific areas of the business: Capital, Intercompany, and Operations and Maintenance. The process that does this is called settlements. In this process, WBS activities are reflected in 7xxxxx and 8xxxxx natural GL accounts and* *allocated to be reflected in income statement or balance sheet accounts. Once the settlements are run, each WBS should be zero. When a WBS is not zero it means a transaction, while in the GL, did not "settle" where it needed to be reflected. This could be either a coding issue or a timing issue."*

"For Granite State and EnergyNorth: The conversion from GP to SAP and Power Plan has resulted in some amounts being reflected under similar categories in Power Plan but not in the GL. $133,283.70 is reflected under account 122 (accumulated provision for depreciation and amortization of nonutility property) in the GL but in Power Plan, it is reflected under account 108 (accumulated provision for depreciation of electric utility plant) because they are both depreciation accounts. The $638,242.47 is Cost of Removal which is reflected under account 242 (miscellaneous current and accrued liabilities) in the GL but in PowerPlan, it is included in account 108 (accumulated provision for depreciation of electric utility plant). The ($146,846.47) and ($240,117.15) seem to be settlement errors as discussed above. At year-end these amounts were reconciling items between the GL and the Power Plan subledger. These amounts have since settled properly."

Audit verified that the 472 Great Plains general ledger accounts and related September 2022 balances transferred into the 827 SAP general ledger. Incidents in which accounts on the FERC Form 1 could not be verified to the SAP related general ledger accounts are noted throughout this report. Audit was informed of specific accounts that had not been coded to the settling account correctly. **Audit Issue #1**

<u>Overview of the FERC Form 1 since the Prior Test Year</u>

Audit compiled a comparative summary of the FERC Form 1 reports from the prior test year 2018, through the current 2022 test year. The balance sheet has increased from $204,902,817 at year-end 2018 to $328,891,720 at year-end 2022, or an increase of 61%. The roll-forward of the FERC Form 1 reflects:

	FERC Form 1 12/31/2018	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Utility Plant	$ 249,231,095	$ 263,916,439	$ 281,663,336	$ 307,083,593	$ 349,877,082
Construction Work in Progress	$ 3,907,980	$ 6,022,727	$ 10,786,906	$ 17,065,613	$ 15,266,206
TOTAL Utility Plant	$ 253,139,075	$ 269,939,166	$ 292,450,242	$ 324,149,206	$ 365,143,288
(Less) Accum Provision for Dep, Amort, Depl	$ (93,623,954)	$ (99,447,339)	$ (106,237,402)	$ (114,595,819)	$ (123,090,712)
Net Utility Plant	**$ 159,515,121**	**$ 170,491,827**	**$ 186,212,840**	**$ 209,553,387**	**$ 242,052,576**
Non-utility Property (121)	**$ 32,086**	**$ 32,086**	**$ 32,086**	**$ 21,466**	**$ 21,466**
Cash (131)	$ 61,175	$ 19,277	$ 61,625	$ (2,074)	$ 43,238,110
Special Deposits (132-134)	$ 26,339	$ 26,962	$ 227,162	$ 5,227,213	$ 32,759
Customer Accounts Receivable (142)	$ 13,051,794	$ 11,815,914	$ 12,512,500	$ 14,130,627	$ 29,736,312
Other Accounts Receivable (143)	$ 107,061	$ 101,650	$ 447,842	$ (193,717)	$ 699,314
(Less) Accum. Provision for Uncollectible credit (144)	$ (818,355)	$ (710,351)	$ (752,496)	$ (734,292)	$ (970,049)
Accounts Receivable from Associated Companies (146)	$ 5,942	$ 74,112	$ 59,984	$ -	$ -
Plant Materials and Supplies (154)	$ 1,877,163	$ 2,950,132	$ 2,538,074	$ 2,400,315	$ 3,759,408
Stores Expense Undistributed (163)	$ -	$ -	$ -	$ -	$ -
Prepayments (165)	$ 1,081,231	$ 1,118,155	$ 1,401,770	$ 1,233,254	$ 1,384,677
Accrued Utility Revenues (173)	$ 1,773,168	$ 1,882,327	$ 2,170,929	$ 2,248,596	$ 3,002,394
Miscellaneous Current and Accrued Assets (174)	$ -	$ -	$ -	$ -	$ -
Total Current and Accrued Assets	**$ 17,165,518**	**$ 17,278,178**	**$ 18,667,390**	**$ 24,309,922**	**$ 80,882,925**
Unamortized Debt Expenses (181)	$ 29,711	$ 26,043	$ 22,183	$ 18,419	$ 14,655
Other Regulatory Assets (182.3)	$ 27,884,536	$ 12,105,227	$ 16,639,767	$ 16,053,793	$ 4,557,561
Preliminary Survey and Investigation Charges Electric (18:	$ 169,765	$ 125,833	$ 125,833	$ 215,709	$ 310,019
Clearing Accounts (184)	$ 106,080	$ 88,627	$ 255,483	$ 303,208	$ 1,052,518
Miscellaneous Deferred Debits (186)	$ -	$ -	$ -	$ -	
Accumulated Deferred Income Taxes (190)	$ -	$ -	$ -	$ -	
Total Deferred Debits	**$ 28,190,092**	**$ 12,345,730**	**$ 17,043,266**	**$ 16,591,129**	**$ 5,934,753**
TOTAL ASSETS	**$ 204,902,817**	**$ 200,147,821**	**$ 221,955,582**	**$ 250,475,904**	**$ 328,891,720**

	FERC Form 1 12/31/2018	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Common Stock Issued (201)	$ 6,040,000	$ 6,040,000	$ 6,040,000	$ 6,040,000	$ 6,040,000
Other Paid-in Capital (208-211)	$ 92,984,903	$ 92,984,903	$ 92,984,903	$ 92,984,903	$ 92,984,903
Retained Earnings (215, 215.1, 216)	$ 4,535,099	$ 8,750,460	$ 20,391,601	$ 32,931,729	$ 44,680,599
Accumulated Other Comprehensive Income (219)	$ 160,041	$ (452,770)	$ (3,471,446)	$ (1,201,967)	$ 3,257,743
Total Proprietary Capital	**$ 103,720,043**	**$ 107,322,593**	**$ 115,945,058**	**$ 130,754,665**	**$ 146,963,245**
Bonds (221)	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000
Advances from Associated Companies (223)	$ 17,000,000	$ 17,000,000	$ 17,000,000	$ 17,000,000	$ 17,000,000
Total Long Term Debt	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**
Obligations Under Capital Leases-Noncurrent (227)	$ -	$ 6,280	$ 583	$ -	$ -
Accumulated Provision for Injuries and Damages (228.2)	$ 17,737	$ 11,389	$ 11,348	$ 10,998	$ 10,998
Accumulated Provision for Pensions and Benefits (228.3)	$ 14,699,662	$ 15,113,443	$ 18,485,313	$ 14,606,247	$ 7,293,207
Asset Retirement Obligations (230)	$ -	$ -	$ -	$ -	$ -
Total Other Non-current Liabilities	**$ 14,717,399**	**$ 15,131,112**	**$ 18,497,244**	**$ 14,617,245**	**$ 7,304,205**
Accounts Payable (232)	$ -	$ -	$ -	$ -	$ 4,513,650
Accounts Payable to Associated Companies (234)	$ 11,350,016	$ 12,881,528	$ 20,996,569	$ 31,963,725	$ 75,125,573
Customer Deposits (235)	$ 1,278,349	$ 1,249,583	$ 1,175,621	$ 1,206,777	$ 1,333,412
Taxes Accrued (236)	$ -	$ -	$ (186,381)	$ 2,091,467	$ 4,330,176
Interest Accrued (237)	$ 142,792	$ 142,792	$ 325,292	$ 142,792	$ 325,292
Tax Collections Payable (241)	$ 43,247	$ 32	$ 14	$ 14	$ -
Miscellaneous Current and Accrued Liabilities (242)	$ 9,841,558	$ 10,016,690	$ 9,433,247	$ 14,998,463	$ 32,120,029
Obligations Under Leases-Current (243)	$ -	$ 7,828	$ 297	$ 13,233	$ 101,750
Total Current and Accrued Liabilities	**$ 22,655,962**	**$ 24,298,453**	**$ 31,744,659**	**$ 50,416,471**	**$ 117,849,882**
Customer Advances for Construction (252)	$ -	$ -	$ -	$ -	
Other Deferred Credits (253)	$ 118,383	$ 117,897	$ 3,949,684	$ 117,127	$ 117,023
Other Regulatory Liabilities (254)	$ 21,716,340	$ 10,863,514	$ 6,194,636	$ 8,313,603	$ 6,913,697
Accumulated Deferred Income Taxes Other (283)	$ 9,974,690	$ 10,414,252	$ 13,624,301	$ 14,256,793	$ 17,743,668
Total Deferred Credits	**$ 31,809,413**	**$ 21,395,663**	**$ 23,768,621**	**$ 22,687,523**	**$ 24,774,388**
Total Liabilities and Stockholder Equity	**$ 204,902,817**	**$ 200,147,821**	**$ 221,955,582**	**$ 250,475,904**	**$ 328,891,720**

Audit calculated the annual percentage change to the balance sheet, with the following results:

2018	2019	2020	2021	2022
2%	-2%	11%	13%	31%

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	Test Year FERC Form 1 12/31/2022	% Change from prior year end
Utility Operating Revenues (400)	$ (102,972,734)	$(104,066,200)	$ (107,899,134)	$(141,928,329)	32%
Operation Expenses (401)	$ 71,874,815	$ 68,230,338	$ 69,445,550	$ 105,270,016	52%
Maintenance Expenses (402)	$ 3,573,702	$ 3,580,477	$ 5,265,408	$ 6,165,689	17%
Depreciation Expenses (403)	$ 7,266,549	$ 8,479,102	$ 9,916,818	$ 10,429,931	5%
Depreciation Expense for Asset Retirement Costs (403.1)	$ -	$ -	$ -	$ -	#DIV/0!
Amortization/Depletion of Utility Plant (404-405)	$ 2,377,447	$ 357,131	$ 167,550	$ 529,378	216%
Regulatory Debits (407.3)	$ 5,830	$ 138,410	$ 282,538	$ 144,128	-49%
Taxes Other than Income (408.1)	$ 5,519,673	$ 5,721,390	$ 6,423,995	$ 6,549,124	2%
Income Taxes-Federal (409.1)	$ -	$ -	$ 2,091,467	$ 2,238,709	7%
Income Taxes -Other (409.1)	$ 95,000	$ 121,623	$ 819,835	$ 873,455	7%
Provision for Deferred Income Taxes (410.1)	$ 1,243,021	$ 4,215,756	$ (346,351)	$ 1,250,385	461%
(Less) Provision for Deferred Income Taxes-credit (411.1)	$ -	$ -	$ -	$ -	#DIV/0!
Investment Tax Credit Adjustment net (411.4)	$ -	$ -	$ -	$ -	#DIV/0!
Total Utility Operating Expenses	$ 91,956,037	$ 90,844,227	$ 94,066,810	$ 133,450,815	42%
NET UTILITY OPERATING INCOME (LOSS)	**$ (11,016,697)**	**$ (13,221,973)**	**$ (13,832,324)**	**$ (8,477,514)**	-39%

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	Test Year FERC Form 1 12/31/2022	% Change from prior year end
(less) expenses of non-utility operations					
Interest and Dividend Income (419)	$ (467,804)	$ (262,376)	$ (482,430)	$ (281,962)	-42%
Allowance for Funds Used during Construction (419.1)	$ (109,324)	$ (207,168)	$ (278,305)	$ (130,600)	-53%
Miscellaneous Non-operating Income (421)	$ -	$ -	$ -	$ -	#DIV/0!
(Gain) or Loss on Disposition of Property (421.1)	$ -	$ -	$ (108,789)	$ -	-100%
Total Other Income	$ (577,128)	$ (469,544)	$ (869,524)	$ (412,562)	-53%
Donations (426.1)	$ 11,216	$ 11,240	$ 6,770	$ 18,841	178%
Life Insurance (426.2)	$ -	$ -	$ -	$ -	#DIV/0!
Penalties (426.3)	$ -	$ -	$ -	$ 1,500	#DIV/0!
Expenses for civic political & related activities (426.4)	$ 15,310	$ 9,173	$ 20,922	$ 21,690	4%
Other Deducations (426.5)	$ 4,162,570	$ (39,312)	$ 301,717	$ (201,344)	-167%
Total Other Income Deductions	$ 4,189,096	$ (18,899)	$ 329,409	$ (159,313)	-148%
Income Taxes-Federal (409.2)	$ -	$ -	$ -	$ -	#DIV/0!
Income Taxes-Other (409.2)	$ -	$ -	$ -	$ -	#DIV/0!
Provision for Deferred Income Taxes (410.2)	$ (98,010)	$ (131,940)	$ (196,020)	$ (196,020)	0%
Total Taxes on Other Income and Deductions	$ (98,010)	$ (131,940)	$ (196,020)	$ (196,020)	0%
Net Other (Income)/Loss and Deductions	**$ 3,513,958**	**$ (620,383)**	**$ (736,135)**	**$ (767,895)**	4%
Interest on Long-term Debt (427)	$ 1,130,500	$ 1,130,500	$ 1,130,500	$ 1,130,500	0%
Amortization of Debt Discount & Expense (428)	$ 2,619	$ 2,619	$ 2,619	$ 2,183	-17%
Interest on Debt to Associated Companies (430)	$ 777,839	$ 784,267	$ 777,839	$ (4,075,337)	-624%
Other Interest Expense (431)	$ 1,941,118	$ 410,972	$ 296,417	$ 518,502	75%
(Less) Allowance for Borrowed Funds Used during Cnstrctn Cr-(432)	$ (69,065)	$ (127,143)	$ (168,534)	$ (79,309)	-53%
NET Interest Charges	$ 3,783,011	$ 2,201,215	$ 2,038,841	$ (2,503,461)	-223%
NET INCOME	**$ (3,719,728)**	**$ (11,641,141)**	**$ (12,529,618)**	**$ (11,748,870)**	-6%
NET INCOME % change year to year	-20%	213%	8%	-6%	

Net Plant in Service $242,052,576

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Utility Plant	$ 263,916,439	$ 281,663,336	$ 307,083,593	$ 349,877,082
Construction Work in Progress	$ 6,022,727	$ 10,786,906	$ 17,065,613	$ 15,266,206
TOTAL Utility Plant	$ 269,939,166	$ 292,450,242	$ 324,149,206	$ 365,143,288
(Less) Accum Provision for Dep, Amort, Depl	$ (99,447,339)	$ (106,237,402)	$ (114,595,819)	$ (123,090,712)
Net Utility Plant	**$ 170,491,827**	**$ 186,212,840**	**$ 209,553,387**	**$ 242,052,576**

The filing schedule does not include the CWIP balance. Reported Plant in Service at 12/31/2022, per the FERC Form 1 was a net $365,143,288. The filing schedule RR-4 indicates the Accumulated Depreciation balance is $123,210,870. This is a $120,158 difference compared to the 2022 FERC Form 1. Audit requested clarification of the exclusion of accounts 15550010108100 Acc Dep-FC-Leg ($1,412.71) and 15550010108100, RWIP (Removal Work in Progress) $121570.85. The Company noted, "*The variance of $120,158 in the GL account 108 Accumulated Depreciation reported balance between FERC Form 1 and RR-4-1 is simply based on a difference in the preparation of the data for two filings.* Additional clarification was requested as to where specifically those two balances can be found within the filing. The Company stated that neither account balance was included in the revenue requirement schedules. The Company then indicated that the "*$121,571 in RWIP is Removal Work in Progress and therefore would not be included in the revenue requirement. The $1,413 in Legacy Costs represent two salvage cash payments. These amounts should have been included in the revenue requirement. They were inadvertently excluded because they were posted directly to the legacy account and therefore never settled properly through a WBS# in SAP to depreciation reports. The Company will consider this, along with any other changes identified during the discovery process, in its next update of the revenue requirement in this proceeding.*" **Audit Issue #2**

The filing schedule RR-4 reflects a total Net Utility Plant of $158,015,121. In 2022 the Company had a beginning balance of $1.5 million in the 105 Plant Held for Future Use account that during 2022 was used to develop the Rockingham Substation. The associated project is 301864, Rockingham SS Land.

On schedule RR-4 on line 14, there are $21 million in rate base offsets that are related to the DE 16-383 for regulatory reporting purposes only and in future rate cases the Company will make $21 million in ADIT adjustments to rate base in accordance with the DE 16-383 Settlement Agreement, Attachment 7 pages 13 and 47. The Company indicated the $21 million ratemaking adjustment did not have any relation to the GL.

The detailed plant in service FERC pages 204-207 sum to the $349,877,082. Page 200 reflects $340,029,912 and $9,847,170 Completed Construction not Classified. The two sum to the $349,877,082. The $21,466 Non-utility Property booked to the 121 account was not included on page 200. The balance sheet on page 110 reflects Utility Plant in Service of $242,052,576 which is the $349,877,082 plus CWIP of $15,266,206 net of accumulated depreciation $(123,090,712). The accumulated depreciation figure was noted on the FERC Form 1 page 200 as a credit on line 14.

FERC Account	2022 FERC Form 1	SAP Account	SAP GL Yr End	Variance
		1010 Plant in Service	$ 300,645,562	
		106 Com. Const Not Class	$ 49,231,519	
101-106, 114	$ 349,877,082		$ 349,877,082	
107	$ 15,266,206	107 CWIP	$ 15,258,393	$ 7,813
Total	$ 365,143,288		$ 365,135,475	

Audit reviewed the Company capital and expense policy most recently revised in July 2022. The Company expensing/capitalization procedures manual was first effective on December 31, 2013. The chart below summarizes the plant activity since the most recent rate case.

TOTAL PLANT ACTIVITY 2019 - 2022

	Beginning Bal	Additions	Retirements	Adjustments	Transfers	Ending Balance	FERC ending pg 207 ln 100
1/1/2019	$ 247,731,096	$ 17,227,348	$ (2,567,520)	$ 25,516	$ -	$ 262,416,440	$262,416,440
1/1/2020	$ 262,416,440	$ 17,534,798	$ (708,823)	$ 920,922	$ -	$ 280,163,337	$280,163,336
1/1/2021	$ 280,163,337	$ 25,979,248	$ (553,580)	$ (5,411)	$ -	$ 305,583,594	$305,583,593
1/1/2022	$ 305,583,595	$ 43,910,073	$ (1,117,090)	$ (504)	$1,501,010	$ 349,877,084	$349,877,082

Test of Additions Closed to Plant since the Prior Audit

Audit requested a listing of projects which were closed to plant in service accounts in 2019-2022. Audit reviewed a total of twelve project three for each year for 2019-2022.

Project #	Project Description	Year	Budgeted Amount	Actual Unitized Amount	Variance (Over)Under	% Variance
8830-1962	Lebanon Area Low Voltage Mitigation	2019	$ -	$ 62,902	$ (62,902)	100%
8830-1954	Install Mt. Support 16L2-16L5 Feeder Ti	2019	$ 200,000	$ 146,450	$ 53,550	-26.77%
8830-1956	Install 13L2-9L3 Feeder Tie	2019	$ 200,000	$ 246,037	$ (46,037)	23.02%
8830-2024	LED Street Light Conversion	2020	$ 200,000	$ 257,404	$ (57,404.00)	28.70%
8830-2025	IT Systems & Equipment Blanket	2020	$ 125,000	$ 47,398	$ 77,601.96	-62.08%
8830-2013	GSE-Dist-Asset Replace Blanket	2020	$ 400,000	$ 83,379	$ 316,620.94	-79.16%
8830-2127	IT Systems Allocations - Corporate	2021	$ 50,000	$ 146,636	$ (96,636.17)	193.27%
8830-2139	IE-NN URD Cable Replacement	2021	$ 500,000	$ 235,107	$ 264,893.00	-52.98%
8830-2119	IE-NN Dist Transformer upgrades	2021	$ 50,000	$ 38,828	$ 11,172.11	-22.34%
8830-2083	Inv. Mgmt Sys Imprvmnt - 10 yr	2022	$ -	$ 110,736	$ (110,736)	100.00%
8830-2241	Feeder Getaway Cable Replacement	2022	$ 250,000	$ 119,779	$ 130,221	-52.09%
8830-2210	GSE-Dist-St Light Blanket	2022	$ 125,000	$ 133,311	$ (8,311)	6.65%
		Total	$ 2,100,000	$ 1,627,968	$ 472,032	

Purchase Order and Invoice Authorization limits were requested and provided:

Level	Value
CEO	Over 7.5 Million
Executive VP	$ 7,500,000
Senior VP	$ 3,500,000
Regional President (LU)	$ 3,000,000
State President, GM & VP (LU)	$ 2,000,000
Vice President	$ 1,000,000
Senior Director	$ 500,000
Director	$ 300,000
Senior Manager	$ 200,000
Manager	$ 100,000
Supervisor	$ 10,000
Staff	TBD

Any commitment of funds in excess of $100,000 for growth, supported, unplanned, and discretionary projects noted within the Policies and Procedures for Capital Expenditures are requirements for the following documentation:

- Business Case detailing the need, justification, and overall cost estimate for the project;
- Capital Expenditure Summary outlining the project costs;
- Spending Schedule which tracks expenses as the project progresses;
- Over-spending Request form for any overspend in excess of 10% of initial cost.
- Project Closeout detailing the final project cost details and lessons learned from the project

<u>121 Non-Utility Property $21,466</u>

In 2021 the 8830-2-0000-10-1610-1210 Non-Utility Property-Land account had a $32,086 beginning balance. The Company in July 2021 sold a portion of the land that was in Salem. The July 2021 land sale was recorded as a retirement that debited the Gain on the Disposition of Property account 8830-2-0000-40-4400-4211 for $10,620 credited the 1210 Non-Utility Property-Land account for ($10,620) that resulted in a December 2021 $21,466 account ending balance. In 2022 there was no account activity in the SAP GL account 15001010121000 that ended with the $21,466 account balance.

<u>Overheads</u>

The Company provided the 2019-2022 capitalized overhead budget calculations for the year that were used to calculate the capitalized overhead rate. The Company provided a CWIP spreadsheet that indicates the capitalized overhead costs include rent, IT, software depreciation, legal, back office, payroll taxes, incentive awards, finance, executive, procurement, health and safety, operations, dispatch, and engineering. The overhead rate is determined by dividing the budgeted costs by the total budgeted payroll that excludes the incentive and back-office payroll.

Liberty stated there is no set rate for burden allocation. Depending on the eligible burden charges in a job, the total population to be allocated, and the amount to be allocated, will determine the amount of burden for each individual job. The burden process is based on actual charges and could fluctuate from month to month depending on the level of construction. Granite State Electric used to have 13 burden identifiers that were streamlined on October 1, 2016 to 4 burden identifiers. The reason for this was to streamline and simplify the burden calculation process for the Company. As part of the review of the plant section, Audit reviewed the Stores, Corporate, LAB, BRD.

The LU corporate overhead is a percentage of direct and indirect charges that are capitalized. The corporate overhead is the capitalization of Liberty Utilities Canada, APUC, and LABS costs based on the INDOH% that is set by corporate. The Regional, US LABS, and Liberty Corporate Services are capitalized for employees located in New Hampshire only, based on percentages set by their managers. The overhead figures are reviewed annually. The eligible cost elements for corporate overhead are labor, inventory, vouchers, and outside services.

The LAB overhead is operational expenses to capitalize the labor split, bonus accrual, payroll accrual, and field labor. This is a predetermined percentage of labor spent working on capital projects that is moved into the capital accounts monthly. The percentages are set on an employee basis determined by the manager that is reviewed annually. The charges in this burden are generally for charges that cannot be charged to other individual jobs. The eligible cost elements for corporate overhead are labor, inventory, vouchers, and outside services.

The BRD overhead consists of benefits charges that are allocated to capital jobs related to labor. This is specifically the operations expenses moved to capitalized labor that is a predetermined percentage. The BRD overhead also consists of benefits charged to direct capital labor and fleet. The fleet burden charges consist of maintenance and fuel charges that are spread proportionality based on labor dollars, and inclusion of the capitalized fleet overhead, discussed below.

The Stores overhead consists of inventory storeroom costs to be allocated with eligible materials costs during a month. The charges consist of bonus accruals and the clearing of the stores account 1380-1630. The purpose of the stores account is to reclassify capital costs that should have been expensed.

The Capitalized Fleet overhead represents a portion of the monthly fleet depreciation expense, capitalized and allocated on a pro-rata basis across open Construction Work in Process (CWIP) jobs. The capitalization is the monthly depreciation expense of grouped asset 8830-3920, multiplied by the quarterly fleet depreciation rate capitalized by CWIP job through the BRD discussed above. The Company has been capitalizing fleet overhead since 2018. The Company indicated they started this because of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 360. ASC 360 relates to Generally Accepted Accounting Principles (GAAP) for property, plant, equipment and related depreciation. The Company capitalizes a portion of depreciation on construction vehicles in account #392, Transportation Equipment, and equipment in account #396, Power Operated Equipment, to FERC account 107 CWIP. The calculated depreciation is posted to regulatory accounts 55056010403000 Capitalized Equipment and 55057010403000 Capitalized Fleet. A journal entry is then done each month to move a percentage of this depreciation expense to the 107 CWIP account where these amounts are allocated across capital projects. The FERC Uniform System of Accounts did not adopt ASC

360. Audit spoke with a FERC accountant who confirmed to Audit that capitalization of standard fleet depreciation does not comply with the FERC USoA. **Audit Issue #3**

Continuing Property Records

The Company provided documentation for each work order that details when the projects were unitized, placed into service, and taken out of Construction Work in Progress. From that documentation, Audit sampled specific transactions, and the Company provided the detailed journal entries. See the review of each project/ work order further in this report that discusses when the work orders were placed into service.

Energy Assistance Program

On June 1, 2023 the DE 21-133 Energy Assistance Program Final Audit Report was issued which identified $140,000 in EAP costs the Company was authorized to recover on June 1, 2021 per Order 26,485 through the EAP/SBC funding mechanism. The Audit issue (#1) further indicates that Liberty, in the updated March 15, 2023 EAP reconciliation filing, recovered the costs associated with the required EAP technical system upgrades that was verified by Audit in the conclusion of Audit issue #1. Because the $140,000 EAP billing system upgrade costs were recovered through SBC funds, the Company is not able to add the plant additions to rate base without at least entering the reimbursement costs as a Contribution in Aide of Construction (CIAC). Since the Company was reimbursed for the upgrade, as the costs were covered by the SBC, the Company should not have left the plant additions to plant in service without a direct CIAC offset. **Audit Issue #4**

Review of Project Additions

The charts below represent the (rounded) Budgeted vs Actual for the 2019-2022 projects reviewed.

2019 Projects	Budgeted	2019 Actual Spent	Difference
8830-1932	$0	$62,902	($62,902)
8830-1954	$200,000	$146,450	$53,550
8830-1956	$200,000	$246,037	($46,037)
Total	$400,000	$455,390	($55,390)

2020 Projects	Budgeted	2020 Actual Spent	Difference
8830-2024	$200,000	$257,404	($57,404)
8830-2025	$125,000	$47,398	$77,602
8830-2013	$400,000	$83,379	$316,621
Total	$725,000	$388,181	$336,819

2021 Projects	Budgeted	2021 Actual Spent	Difference
8830-2127	$50,000	$146,636	($96,636)
8830-2139	$500,000	$235,107	$264,893
8830-2119	$50,000	$38,828	$11,172
Total	$600,000	$420,571	$184,023

2022 Projects	Budgeted	2022 Actual Spent	Difference
8830-2083	$0	$110,736	($110,736)
8830-2241	$250,000	$119,779	$130,221
8830-2210	$125,000	$133,309	($8,311)
Total	$375,000	$363,826	$11,174

Audit performed a review of the Company budgeted/actual costs and noted numerous instances of the project/work order estimate not being very accurate. The Company when asked for a reason to explain the variances indicated to review the Project Closeout Report which on most of the reports reviewed due not give a specific reason for why a project was over or under the budget that is very descriptive. **Audit Issue #5**

Review of Staff Data Request 3-1 8830 Unallocated Burden Project

Project ID	Year	Project Description	Budget	Actual	Variance ($) (over)/under	% Variance (over)/under
8830-UNALLOC OH	2019	Finance Unalloc Burden	$ -	$ 309,595	$ (309,595)	
8830-UNALLOC OH	2020	Finance Unalloc Burden	$ 384,069	$ 843,160	$ (459,091)	-120%
8830-UNALLOC OH	2021	Finance Unalloc Burden	$ 193,063	$ 631,619	$ (438,556)	-227%
8830-UNALLOC OH	2022	Finance Unalloc Burden	$ 191,500	$ 2,730,627	$ (2,539,127)	-1326%
		Total	**$ 768,632**	**$ 4,515,002**	**$ (3,746,370)**	

The response to Staff Data Request 3-1 for 2019-2022 included a project ID 8830-Unallocated Overhead/Burden. The budgeted costs were $768,632 while the actual capital spending was $4,515,002. This is a ($3,746370) over budget. The Company clarified that this project represented capital spending not a project that was unitized to plant in service. The $4,515,002 capital spending is the cost remaining at the end of a given year. The Company clarified the unallocated finance burden is a vehicle to hold CWIP costs before being allocated to actual construction/purchasing jobs.

The overhead rates are determined by forecasting the overhead cost divided by the forecasted eligible capital amount spent. The eligible capital burdens include direct labor, materials, vouchers, and outside services that was in accordance with the most recently updated January 31, 2020 New Hampshire Capital Overhead Procedure Manual. The procedure manual explains how general accounting entries for overhead are done monthly by debiting the overhead/burden and crediting the individual job based on calculated rate and eligible spending. The Company on October 1, 2022 began using SAP and since that time, labor burdens follow labor charges directly to individual projects.

Projects Tested
2019 Projects

8830-1962 Lebanon Area Low Voltage Mitigation

Unitized in 2019 8830-1962 Lebanon Low Voltage 16L5 Feeder $62,903

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	0	
Cost Element 2-Stores and Materials	$	13,211	
Cost Element 4-Vouchers	$	4,999	
Cost Element 5-Outside Services	$	0	
Cost Element 6- Burden	$	44,693	
Cost Element 7-Cost of Removal	$	0	
Cost Element 9-AFUDC	$	0	
Total of all costs for the job:	$	62,903	
Cost Element 3-Reflects the 2019 Transfer to Plant	$	(62,903)	1/27/2020

Cost Element 3-reflects the 2018 Transfer to Plant	$	($114,037)	1/27/2020
Net Plant Asset Detail Total Project		($176,940)	

Audit reviewed solely the $62,903 2019 project costs associated with project 8830-1962 that was for Lebanon Mount Support 16L5 feeder project. All costs in 2019 are related to reallocation of costs associated with projects completed in prior years. Based on a review of the plant asset charge detail the project was charged to 8830-C36435 rather than 8830-1962. The project also consisted of 2018 costs of $114,037. The project was unitized and moved from the 107 CWIP account to the 106 Completed Construction Non-Classified plant in service account on January 27, 2020 for $176,940. Based on a review of Plant System data the project is 8830-C36435 rather than 8830-1962 as provided in a list of actual projects unitized to plant in service.

Review of payroll, invoices, materials, and overhead support

	2018	2019	Total
Contractors	$ 26,723	$ 4,999	$ 31,722
Labor	$ 38,863		$ 38,863
Materials	$ 1,520	$13,211	$ 14,731
Overheads	$ 46,931	$44,693	$ 91,624
Total	$ 114,037	$62,903	$ 176,940
Overheads	41.15%	71.05%	51.78%

Materials

The Company provided the journal entries of three transactions from February and March 2019 that were for utility poles, and electrical cable. The entry indicates the Company used thirteen 40-foot utility poles that were from February 24, 2019 that was for $4,387. The Company on March 29, 2019 that was for 4,454 of spacer cable that was for $4,050. The Company did not provide any actual invoices or historical inventory records such as materials tickets. **Audit Issue #5**

Overheads

The project has a 51.78% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Invoices

Audit reviewed a January 2019 invoice that was $760 and a $760 June 2019 Hunter North Associates invoices that summed to $1,520 that was for flagging/traffic control. Audit verified the hours worked and hourly rates charged on the invoices were calculated correctly.

Audit reviewed a $1,988 January 2019 JCR Construction Company invoice that was for the installation of rock bolts on poles and installation of anchors on utility poles. Audit verified the hourly rates and hours worked on the invoice were calculated correctly.

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for the $19,278. **Audit Issue #6**

Retirements

The Company provided the $5,114 Quarter 1, 2020 retirements that were done. The Company retired 390 assets in Enfield. The assets retired were noted from the following:

Account	Quantity	Amount
364	13	$2,321
365	3,172	$2,125
368.2	10	$668
Total	390	$5,114

Bids and Project Documentation

GSE indicated there is no 2019 project documentation for the Lebanon Area Low Voltage Mitigation project as it was a carryover project from prior years. All costs in 2019 are related to reallocation of costs associated with projects completed in prior years. Based on a review of the plant asset charge detail the project was charged to 8830-C36435 rather than 8830-1962.

<u>8830-1954 Install Mt. Support 16L-16L5 Feeder Tie</u>

<u>Unitized in 2019 8830-1954 Mt. Support Leb. 16L2-L5 Feeder $146,451</u>

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 45,540	
Cost Element 2-Stores and Materials	$ 21,210	
Cost Element 4-Vouchers	$ 15,107	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 64,053	
Cost Element 9-AFUDC	$ 541	
Total of all costs for the job:	$ 146,451	
Cost Element 3-Reflects the 2018-2019 Tran to Plnt	$ (146,451)	9/1/2019
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ ($13,244)	9/1/2019
Net PowerPlan Detail Total Project	($159,695)	

Audit reviewed project 8830-1954 that was to tie the Mt. Support feeder 16L2-L5 in Lebanon. The legacy WennSoft plant asset charge detail indicates the project is 8830-1854. Audit reviewed $146,451 in 2018 and 2019 project costs that were unitized on September 1, 2019 per the PowerPlan GL data to the 106-plant account and the 365 overhead conductor's account. The Company indicated in 2020 there were an additional $13,244 in 2020 plant costs. The 8830-1854 project was unitized to plant in service for $159,695. The Company in October 2022 began using the PowerPlan fixed asset system and the journal entry screenshot indicates the entire project was unitized to plant for $154,695 on September 1, 2019.

<u>Review of payroll, invoices, materials, and overhead support</u>

	2018	2019	2020	Total	Total Overhead
Contractors		$ 15,107	$ 873	$ 15,980	
Labor	$ 3,794	$ 41,746		$ 45,540	
Materials	$ -	$ 21,210	$ 445	$ 21,655	
Overheads	$ 6,807	$ 57,246	$11,926	$ 75,979	47.58%
AFUDC	$ 111	$ 430		$ 541	
	$10,712	$ 135,739	$13,244	**$ 159,695**	

<u>Materials</u>

The Company provided the journal entries for two December 6, 2019 entries that was for one load break switch that was for $3,807 and 9 50-foot wood poles that were for $4,592. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

<u>Invoices</u>

Audit reviewed an April 2019 Asplundh Tree Expert invoice that was for $2,387. The work consisted of tree clearing/removal. Audit verified the hours worked and hourly rates charged on the invoice was calculated correctly.

Audit reviewed a June 2019 $1,568 Hunter North Associates Invoice that was for flagging/traffic control personnel. Audit verified the hours worked and hourly rates charged on the invoice were calculated correctly.

Payroll

Audit reviewed a $3,037 bi-weekly payroll report from April/May 2019 that was for labor installation on the substation of spacer cable. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Overheads

The project has a 47.58% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Project Bids and Documentation

This project did not go out to bid as it was done using internal Company labor.

Audit reviewed the signed March 2019 Business Case that was for internal labor to install a Mt. Support 16L2-16L5 feeder tie in Lebanon. This was a discretionary project that was rationalized for Company spending as an improvement to resolve load planning criteria to reduce outages along Route 120 near Dartmouth College. The project installed 1,250 feet of 477 spacer cable along Lahaye Drive in Lebanon. The project was budgeted in 2019 at an estimated cost of $200,000 and to be completed in calendar year 2019. The Project Capital Expenditure Form was authorized for up to $200,000. The form was signed in March 2019 by the requisitioner, Senior Engineering Director with authorization authority up to $250,000, and the VP of Finance and Administration.

Audit reviewed the March 2020 project closeout documentation that was signed by the Electric Engineering Director, and VP of Engineering. The project indicates the project's budgeted costs were $200,000 and the actual costs were $135,738.72. This is $64,261 cost under run, and it is under the budgeted amount. The project per the review by Audit was unitized to plant in 2020 for $146,450 based on a review of the project detail provided by the Company. This is a $10,712 that is the result of 2018 project additions.

Cost of Removal

There were not any cost of removal charges for this project because the Company specified it was an install only.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog was noted to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

8830-1956 Install 13L2-9L3 Feeder Tie

Unitized in 2019 8830-1956 Install 13L2-9L3 $246,037

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 2,729	
Cost Element 2-Stores and Materials	$ 30,310	
Cost Element 4-Vouchers	$ 181,496	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 29,332	
Cost Element 9-AFUDC	$ 2,170	
Total of all costs for the job:	$ 246,037	
Cost Element 3-Reflects the 2018-2019 Tran to Plnt	$ (246,037)	11/1/2019
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ $61,633	11/1/2019
Net PowerPlan Detail Total Project	($184.404)	

Audit reviewed the project 8830-1956 that was to install a 13L-9L3 feeder tie in Londonderry. The WennSoft legacy plant asset charge detail indicates the project is 8830-1856. Audit reviewed $246,037 in 2018 and 2019 charges that were assets that were unitized on November 1, 2019. In 2020 the Company had a ($61,633) credit adjustment reducing the entire project to $184,404. The PowerPlan plant asset system indicates the entire project was unitized to plant in service account 106 completed construction for $184,404 on November 1, 2019. The 365 overhead conductors were booked for the same amount.

Review of payroll, invoices, materials, and overhead support

	2018	2019	2020	Total	Overhead
Contractors	$10,123	$ 171,373	$ (78,964)	$ 102,532	
Labor	$ 1,854	$ 875		$ 2,729	
Materials	$ -	$ 30,310	$ (621)	$ 29,689	
Overheads	$ 6,101	$ 23,231	$ 17,952	$ 47,284	25.64%
AFUDC	$ 296	$ 1,874		$ 2,170	
	$18,374	$ 227,663	$ (61,633)	**$ 184,404**	

Materials

The Company provided the December 2019 journal entries for the replacement of nine wooden poles and one switch. The total transaction was for $8,399. The Company did not provide the complete historical inventory tickets or invoice receipts. **Audit Issue #5**

Invoices

Audit reviewed an October 2019 JCR Construction Company invoices that was for $72,875 for work performed on the 9L3/3L2 Feeder tie project on Roulston Road in Windham. The work consisted of construction work and construction rental equipment. Audit verified the hours worked and hourly rate was calculated correctly.

Audit reviewed two Asplundh Tree Expert invoices that were from April and May 2022 that both summed to $7,233. The work consisted of tree trimming and clearing. Audit verified the hours work and hourly rates charged were calculated correctly on the invoices.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Cost of Removal

There were not any cost of removal charges for this project because the Company specified it was an install only.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

Project Bids and Documentation

This project did not go out to bid because it was done internally by the Company.

Audit reviewed the March 2019 Business Case that was for internal labor to install a 13L2-9L3 feeder tie in Windham. The discretionary project was a system improvement to extend 2,000 feet of three phase 1/0 AL tree wire from pole 26 on Rockingham Rd. to pole 22 on Roulston Rd in Windham. This was done for the purpose of creating a new feeder tie between the 9L3 feeder and to the Spicket River 13L2 feeder. The project was recommended to provide a backup supply for outages or issues along Sears/Rockingham Rd in Windham. The project provides a backup for an area experiencing load growth. The project was budgeted in 2019 at an estimated cost of $200,000 and to be completed in calendar year 2019. The Business Case Capital Expenditure was authorized for up to $200,000. The form was signed/approved by the requisitioner, Senior Engineering Director with authorization authority up to $250,000, and the VP of Finance and Administration.

The Company was not able to locate the Project Capital Expenditure Form. **Audit Issue # 5** Audit reviewed a signed March 2020 Change Order Request Form increasing the authorized amount from $200,000 to $227,671.64. This is a $27,671.64 increase. The Change Order Form justifies the basis for increasing the authorized the over spent amount as being driven by an accrual for $85,000 related to construction costs that were invoiced at the same time. The form indicates with a reversal of the accrual the total project costs will be below the budget. The

Change Order Request was signed by the Manager of Electrical Engineering and the Senior Director of Engineering.

Audit reviewed the signed March 2020 Project Closeout Form that indicates the project was ($27,671.64) over budgeted. The budgeted costs were $200,000 and the actual costs were $227,671.64. The cost over-run was the result of an $85,000 accrual at the end of 2019 which resulted in the project appearing to be overspent. The closeout notes the Project Manager will work with Finance to ensure the accrual has been reversed. The Closeout was signed by the Manager of Engineering and the Senior Director of Engineering. The Closeout indicates most of the charges were external rather than internal. The project was unitized to plant in service for $246,037 based on 2018 and 2019 project costs. This is a $18,365 increase compared to the project closeout. In 2020 there was a ($61,633) cost adjustment related to the accrual adjustment. This brought the total cost of the project to $184,404. The project was done externally perhaps the project should have gone out to bid. **Audit Issue #5**

2020 Projects

8830-2024 LED Street Light Conversion

Unitized in 2020 8830-2024 LED Streetlight Conversion $257,404

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 25,255	
Cost Element 2-Stores and Materials	$ 124,059	
Cost Element 4-Vouchers	$ 5,837	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 116,488	
Cost Element 8- CIAC	$ (27,180)	
Cost Element 9-AFUDC	$ 12,945	
Total of all costs for the job:	$ 257,404	
Cost Element 3-Reflects the 2019-2020 Tran to Plnt	$ (257,404)	8/1/2020
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ (41,816)	12/31/2021
Net PowerPlan Detail Total Project	($299,220)	

Audit reviewed the 2020 8830-2024 LED Streetlight conversion project. The WennSoft legacy plant detail indicates this was project 8830-1924. Audit reviewed $257,404 in 2019 and 2020 project costs that were unitized to plant in service on August 1, 2020. The total project included an additional $41,816 in 2021 plant additions to bring the entire project to $299,220. The PowerPlan plant system indicates the entire project was unitized to plant in service 101 and booked to the 373 Streetlights account for $299,220.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overhead
Contractors	$ 2,490	$ 3,347	$ 1,965	$ 7,802	
Labor	$ 23,837	$ 1,418	$ 3,957	$ 29,212	
Materials	$ 118,341	$ 5,718	$17,034	$ 141,093	
Overheads	$ 108,981	$ 7,507	$18,860	$ 135,348	45.23%
AFUDC	$ 2,161	$10,784		$ 12,945	
CIAC	$ (27,180)	$ -	$ -	$ (27,180)	
Total	$ 228,630	$28,774	$41,816	$ 299,220	

Materials

The Company provided the journal entries for 118 September-December 2020 that was for the installation of Luminaire LED 48W, 50W, and 130W Type II roadway streetlights. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Payroll

Audit reviewed a $875 bi-weekly payroll report from November 2019 that was for labor installation of municipal streetlights. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Overheads

The project has a 45.23% overhead rate. The Company just gave a generic answer that overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

CIAC

The Company provided the signed April 2019 Town of Salem $27,180 contract for LED conversion phase 2 for the replacement of old municipal streetlights. The signed agreement included the replacement of old halogen fixtures with LED streetlights along with any underappreciated value. The Company provided the cash journal entry from May 13, 2019. The Company debited the Cash account 8830-2-0000-10-102-1310 for $27,180 and credit the CWIP account 8830-2-0000-10-1618-1070 for the same amount.

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $17,978 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $57,907. **Audit Issue #6**

Retirements

The Company provided the Quarter 4, 2022 list of retirements that were done for streetlights that summed to $374,843 based on the retirement of 152 streetlights that were booked to the 10101000-plant account.

Project Bids and Documentation

This LED Street Light Conversion project was done using internal resources, so the project did not go out to bid.

There was not a Business Case for this project because the LU Capital Policy does not require one for this type of project. The March 2020 signed Capital Expenditure Form authorized $400,000 based on historical budgeted amounts from prior years. The Project Capital Expenditure Form was signed/approved by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and State President up to $500,000.

The Project Closeout Report was signed in March 2021 by the Manager of Electrical Engineering and VP of Electrical Engineering. The Closeout Report indicates the budgeted project costs were $200,000 while the actual project costs were $82,117.60. This is a $117,882 cost under run that was the result of CIAC charges offsetting accrual charges in 2020. The closeout indicates the remaining budget was reallocated to other 2020 capital projects. The project was closed out to plant in service for $257,404 for 2019 and 2020 project costs. This is a $175,286 difference compared to what was unitized to plant in service. **Audit Issue #5**

8830-2025 IT Systems and Equipment Blanket

Unitized in 2020 8830-2025 IT Systems and Allocations $47,398

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	(78)	
Cost Element 2-Stores and Materials	$	0	
Cost Element 4-Vouchers	$	106,689	
Cost Element 5-Outside Services	$	0	
Cost Element 6- Burden	$	49,835	
Cost Element 3- Transfer to 106	$	109,049)	
Cost Element 9-AFUDC	$	0	
Total of all costs for the job:	$	47,398	
Cost Element 3-Reflects the 2019-2020 Tran to Plnt	$	(47,398)	12/31/2020

Audit reviewed project 8830-2027 that was a blanket project for IT systems and allocations for the year. Audit reviewed a portion of the project that summed to $47,398 that was for a Quandra System upgrade. This blanket project is for the purchase of IT assets such as computers, servers, upgrades, and other technological needs of the Company each year. The legacy WennSoft charge detail indicates the costs reviewed are part of three projects 8830-1825, 8830-1925, and 8830-2025. The GL indicates the project was unitized to plant in service account

106 Completed Construction Not Classified. The project was also booked to the 303-software account.

Review of payroll, invoices, materials, and overhead support

	2019	2020	Total	Overheads
Contractors	$ 71,974	$ 34,715	$ 106,689	
Labor		$ (78)	$ (78)	
Materials			$ -	
Overheads	$ 1,470	$ 48,365	$ 49,835	105.14%
AFUDC			$ -	
Transfer to 106	$ (27,310)	$ (81,739)	$(109,049)	
Total	$ 46,134	$ 1,263	$ 47,398	

Overheads

The project has a 105.14% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Invoices

Audit reviewed a September 2019 Softchoice invoice that was for $7,600 that was for the purchase of five Dell Latitude Laptop computers. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed the December 31, 2019 $54,085 Liberty Utilities Canada Capital bill for Granite State Electrics share of the allocation that was 6.95%

Cost of Removal

There were not any cost of removal charges for this project provided by the Company. The Company indicated install only projects do not have any cost of removal charges associated with them. This project was for the installation of a Quandra Software Upgrade so there would not be a cost of removal charges.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue # 5**

Project Bids and Documentation

This project did not go out to bid because it was done using internal Company resources. Based on a review of the cost details most of the charges are for contractors rather than labor so the Company should have considered putting the project out to bid. **Audit Issue #5**

The Blanket Project Authorization Form was for the replenishment of IT purchases, software, equipment, and infrastructure. The project was authorized to spend up to $125,000 and signed/approved in April 2020 by the IT Manager authorized up to $25,000 and Director of IT authorized up to $250,000. The April 2020 Capital Expenditure Form authorized spending of up $125,000 for IT Equipment/Infrastructure. The form was signed/approved by the IT Manager and Director of IT.

The March 2021 Project Closeout was signed by the IT Manager and IT Director. The project indicates the budgeted amount was $125,000 and the actual amount spent was $183,976. This is a ($58,796) cost over-run that was the result of a $71,624.32 Quandra Upgrade allocated to project 8830-2027. Audit reviewed $47,398 of the $71,624 Quandra upgrade costs.

8830-2013 Distribution Asset Replacement

Unitized in 2020 8830-2013 Distribution Asset Replacement $83,378

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 28,874	
Cost Element 2-Stores and Materials	$ 12,492	
Cost Element 4-Vouchers	$ 1,640	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 40,372	
Cost Element 9-AFUDC	$ 0	
Total of all costs for the job:	$ 83,378	
Cost Element 3-Reflects the 2020 Tran to Plnt	$ (83,378)	12/1/2020
Cost Element 3-reflects 2021-2022 Assets Transfer to Plant	($102,548)	12/31/2022
Net PowerPlan Detail Total Project	($185,926)	

Audit reviewed project 8830-2013 that is a blanket project for the replacement of distribution assets. Audit reviewed solely $83,378 in 2020 project costs out of $185,926 in total project costs. The additional project costs contained 2021 and 2022 plant additions. The Distribution Asset Replacements were booked to the 106 completed construction account on December 1, 2020. The entire $185,926 that was closed to PowerPlan 101 in service with the conversion to SAP in October 2022 included 2021 and 2022 costs.

Review of payroll, invoices, materials, and overhead support

	2020	Overheads
Contractors	$ 1,640	
Labor	$28,874	
Materials	$12,492	
Overheads	$40,372	48.42%
AFUDC		
Transfer to 106		
Total	$83,378	

Materials

The Company provided the October 1, 2020 journal entry one box and utility splicer cable that was for $1,649. Audit reviewed a December 2020 entry for six fifty foot wood poles for $2,680. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Invoices

Audit reviewed two December 2020 Town of Salem invoices that was for $3,000 for police services related to work on the utility construction project.

Payroll

Audit reviewed a $4,388 bi-weekly payroll report from October and December 2020 that was for labor installation of conduit and other electrical distribution station assets. Audit was able to verify the hourly pay multiplied by the hours worked.

Overheads

The project has a 48.42% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $7,724 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $33,809. **Audit Issue #6**

Retirements

The Company provided the $2,211 December 2020 assets that were retired in Enfield. The Company retired 73 Poles, cables, cutouts, and switches.

Account	Asset	Quantity	Amount
364	Poles	10	$401
365	Cable/Switch	63	$1,810
Total		73	$2,211

Project Bids and Documentation

This project did not go out to bid because it was done using internal Company resources.

A Business Case was not required because per LU Capital Project this was a blanket annual project. The signed/approved February 2020 Project Capital Expenditure Form indicates the mandated annual blanket project was for the replacement of line or substation assets based upon the inspection of asset condition and data. The project was authorized to spend $400,000 based on historical past spending. The CAF was signed by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and the State President up to $500,000.

The Closeout was signed/approved by the Manager of Electrical Engineering and Senior Director of Engineering in March 2021. The closeout indicates the budgeted cost of the project was $400,000 while the actual cost of the project was $136,432. This is a $263,562 cost under run per the closeout report. The Company unitized $185,925 to plant in service for project 8830-2013 for the entire project. This is a $49,493 difference compared to what was unitized to plant in service. **Audit Issue #5**

2021 Projects

8830-2127 IT Systems Allocations-Corporate

Unitized in 2020 8830-2127 IT Systems and Allocations $146,637

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 0	
Cost Element 2-Stores and Materials	$ 0	
Cost Element 4-Vouchers	$ 146,757	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ (120)	
Cost Element 9-AFUDC	$ 0	
Total of all costs for the job:	$ 146,637	
Cost Element 3-Reflects the 2019-2021 Tran to Plnt	$ (146,637)	12/1/2021

Audit reviewed project 8830-2127 that was an IT project done at the corporate level for work related to a Customer Information System project upgrade. The project was booked to the plant in service 106 account completed construction on December 1, 2021 and was booked to the 303 Software account.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overheads
Contractors	$15,858	$ 4,281	$ 126,618	$ 146,757	
Labor				$ -	
Materials				$ -	
Overheads			$ (120)	$ (120)	-0.08%
AFUDC				$ -	
CIAC				$ -	
Total	$15,858	$ 4,281	$ 126,498	$ 146,637	

Invoices

Audit reviewed a $125,777 Liberty Utilities Canada Invoice that was from September 2021. The charges represent GSE IT capital allocation of 7.08% out of $890,501 in IT capital spending in 2021.

Cost of Removal

There were not any cost of removal charges for this project provided by the Company. The Company indicated install only projects do not have any cost of removal charges associated with them. This project however was a blanket for a variety of different IT project allocations such as purchasing computers, servers, and any other technological needs so the Company should have booked cost of removal charges. **Audit Issue #5**

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

Project Bids and Documentation

The Company provided the Oakville Corporate Business Case originally from November 2017 but amended in February 2019 for the Enterprise Customer and Communications Convergence Technology Infrastructure Upgrade. The Corporate project was for the upgrade of a new Customer Service Information System. The Company was unable to locate the Capital Expenditure Form. **Audit Issue #5**

This project was executed at the corporate level and not bid by the local NH Staff. The project was for a Call Center Customer Information System software upgrade. The backup provided was an allocation summary by division that is a summary of a IVR PHONSYS Enterprise Infrastructure C3 upgrade project. GSE was allocated $260,681 or 6.23% out of $6,163,243 of the total project. The Company received four qualified bids and based on a scoring rubric Altivion/Longview was the selected winning bidder. The project document was signed in June 2021 by the Corporate IT Director to close out the project division allocation. The project in 2021 was unitized to plant in service for $146,637.

8830-2139 IE URD Cable Replacement

Unitized in 2021 8830-2139 URD Cable Replacement $235,107

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 48,967	
Cost Element 2-Stores and Materials	$ 21,784	
Cost Element 4-Vouchers	$ 75,493	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 127,054	
Cost Element 8-CIAC	$ (40,000)	
Cost Element 9-AFUDC	$ 1,809	
Total of all costs for the job:	$ 235,107	
Cost Element 3-Reflects the 2019-2021 Tran to Plnt	$ (235,107)	6/1/2021
Cost Element 3-reflects the 2021-2022 Assets Trans. Plnt	($326,647)	12/31/2022
Net PowerPlan Detail Total Project	($561,754)	

Audit reviewed project 8830-2139 that was for an Underground Residential Distribution Cable (URD) in Pelham. Audit reviewed solely $235,107 in project costs unitized in 2021 that was part of a larger $561,754 project that included legacy WennSoft projects 8830-1939, 8830-2039, and 8830-1870. The $561,754 was unitized to plant in service when GSE transitioned to SAP in October 2022 and contained additional project costs that were from 2021 and 2022. The 2021 8830-2139 project was unitized to plant in service 106 Completed Construction Non-Classified and the 367 Underground Conductors and Devices.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overheads
Contractors	$60,417	$ 5,936	$ 9,140	$ 75,493	
Labor	$ 9,474	$ 36,703	$ 2,790	$ 48,967	
Materials	$ 2,085	$ 19,146	$ 553	$ 21,784	
Overheads	$14,275	$ 92,054	$ 20,725	$ 127,054	54.04%
AFUDC		$ 1,809		$ 1,809	
CIAC		$ (40,000)		$ (40,000)	
Total	$86,251	$ 115,648	$ 33,208	**$ 235,107**	

Invoices

Audit reviewed a July 2021 D.R. Key Corp. $5,280 invoice that was for construction work and materials associated with the cable replacement. The charges included materials used such as dump trucks, debris removal, excavation, trailers, and wheelbarrows. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed a $55,154 February 2020 Novinium invoice that was for labor associated with the installation of the new 15kV cable. Audit verified the hourly rate and hours worked were calculated correctly on the invoice.

Audit reviewed an August 2021 Parsons invoice that was for $2,739 that was for engineering, consulting, and mileage reimbursement associated with the 15kV cable installation project. Audit verified the hours worked and hourly rate charged on the invoice was calculated correctly.

CIAC

The Company provided the signed May 2020 Miscellaneous Construction agreement for $40,000 for the installation of a new electrical line and two new utility poles for an apartment building complex in West Lebanon. Audit reviewed the $40,00 cash check and the supporting cash journal entry. The journal entry debited the Cash account 8830-2-0000-10-1020-1310 for $40,000 and credited the CWIP account 8830-2-0000-10-1618-1070 for the same amount.

Overheads

The project has a 54.04% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation account #8830-2-0000-10-1655-1084 for $5,350 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $1,467. **Audit Issue #6**

Retirements

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

Project Bids and Documentation

The project did not go out to bid because it was done using internal Company resources.

Audit reviewed a URD cable replacement Business Case from January 2021 that was signed/approved by the Manager of Electrical Engineering and the Senior Director of Electrical Engineering. The Business Case was authorized to spend up to $500,000. The 8830-2139 URD Cable Replacement project was a discretionary project that aims to improve aims to provide resolution to improve reliability/address pocket problems in the URD/UCD. The injection of cable rejuvenation fluids can extend the operating life of poor performing cable. The cable replacement can also reduce poor performing cable disruptions.

Audit reviewed a signed/approved January 2021 Project Capital Authorization Form that authorized up to $500,000 for the URD Cable Replacement project. The January 2021 Capital Expenditure Form was signed/approved by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and State President up to $500,000.

Audit reviewed a signed/approved January 2022 Project Closeout report that indicated the project was budgeted for $500,000 but only actually spent $36,295. This is a $463,705 under budgeted amount because the project scope was reduced to engineering only and excluded construction. The project was unitized to plant in service for $235,107. This is a $198,812 difference compared to the Project Closeout. **Audit Issue #5**

8830-2119 IE-NN Transformer Upgrades

Unitized in 2021 8830-2119 Transformer Upgrade $38,828

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	12,146
Cost Element 2-Stores and Materials	$	3,225
Cost Element 4-Vouchers	$	868
Cost Element 5-Outside Services	$	0
Cost Element 6- Burden	$	22,544
Cost Element 9-AFUDC	$	44
Total of all costs for the job:	$	38,827
Cost Element 3-Reflects the 2020-2021 Tran to Plnt	$	(38,827) 12/1/2021

Cost Element 3-reflects the 2021-2022 Assets Trans. Plnt	($32,200)	12/31/2022
Net PowerPlan Detail Total Project	($71,027)	

Audit reviewed project 8830-2119 that was for a transformer upgrade in Salem that was part of a larger $71,027 project. Audit solely reviewed $38,827 of the project costs that were unitized to plant in 2021. The project also contained the legacy WennSoft projects 8830-2019 and 8830-1919. The project costs Audit reviewed was unitized to plant in service 106 Completed Construction Non-Classified on December 1, 2021 for $38,827. The entire project was unitized to plant in service 101 account for $71,027 in December 2022 that contained additional 2021 and 2022 project costs since the Company transition to SAP in October 2022.

Review of payroll, invoices, materials, and overhead support

	2020	2021	Total	Overheads
Contractors		$ 868	$ 868	
Labor	$ 1,578	$10,568	$12,146	
Materials	$ 1,708	$ 1,517	$ 3,225	
Overheads	$ 2,890	$19,654	$22,544	58.06%
AFUDC	$ 44		$ 44	
CIAC			$ -	
Total	$ 6,220	$32,607	**$38,827**	

Materials

The Company provided the journal entry for an August 14,2021 for two cross arms that were for $513. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue # 5**

Invoices

Audit reviewed an August 2021 $488 Town of Salem invoice that was for police services associated with a construction site for the transformer upgrade project. Audit verified the hours worked and hourly rate on the invoice were calculated correctly.

<u>Overheads</u>

The project has a 58.06% overhead rate and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

<u>Project Bids and Documentation</u>

This project did not go out to bid because it was done using internal Company resources.

There is no Business Case for this project because it was not required by the LU Capital Policy as it is a planned replenishment project. The project was authorized to spend $76,500. The distribution transformer upgrade program is a proactive load-based replacement program beyond what is already being performed during customer service upgrades and system improvement projects. The Capital Expenditure Form was signed in January 2021 by the Manager of Electrical Engineering up to $25,000 and the Senior Director of Electrical Engineering up to $250,000.

Audit reviewed the signed/approved February 2022 Project Closeout Report that indicated the project cost $33,293 and the budgeted amount indicates the project was for $50,000. The project was $16,707 under budget per the closeout report. The closeout report was signed/approved by the Project Supervisor, Electrical Engineering Manager, and the Senior Director of Electric Operations. Based on a review of the plant detail by audit the actual cost was $38,828. This is a $5,535 difference compared to the Project Closeout. **Audit Issue #5**

<u>Cost of Removal</u>

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation account #8830-2-0000-10-1655-1084 for $4,274.

<u>Retirements</u>

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

<u>2022 Projects</u>

<u>8830-2083 Ten Year Inventory System Improvements</u>

<u>Unitized in 2022 8830-2083 10 Year Inventory System Improvements $110,735</u>

Audit was provided with the Plant asset system summary of expenses:

Cost Element 4-Vouchers	$ 85,331
Cost Element 6- Burden	$ 25,404
Cost Element 9-AFUDC	$ 0
Total of all costs for the job:	$ 110,735
Cost Element 3-Reflects the 2020-2022 Tran to Plnt	$ (110,735) 8/1/2021

Audit reviewed project 8830-2083 that was for an inventory management solution as the prior Great Plains System was reported by Liberty to be a cumbersome manual process with many delays, data entry, and batch processing. The PowerPlan screenshot provided to Audit indicates the project was closed to the 106 Completed Construction on August 1, 2021, and booked to the 303-software account for $110,735 in August 2022. The inventory management solution system remains in place, and in conjunction with the SAP software change. The charges were booked over a multi-year period.

Review of payroll, invoices, materials, and overhead support

	2020	2021	2022	Total	Overheads
Contractors	$ 30,804	$54,527		$ 85,331	
Labor				$ -	
Materials				$ -	
Overheads	$ 10,090	$15,314		$ 25,404	22.94%
AFUDC				$ -	
Unitized				$ -	
Total	$ 40,894	$69,841	$ -	**$ 110,735**	

Invoices

Audit reviewed three Data System International (DSI) invoices from April and June 2020 that summed to $25,268 that was for the purchase of a 4.3” Zebra 53 STD Key Alphanumeric handheld data entry device to help with data optimization for materials data entry in the field. The other charges on the invoice were the Cloud internet charges and associated licenses. Other charges consisted of device battery packs, power supply and power cords. Audit verified the charges on the invoices were calculated correctly.

Audit reviewed a $54,527 Liberty Utilities Canada Invoice that was from August2021. The charges represent GSE IT capital allocation of 7.08% out of $890,501 in IT capital spending in 2021.

Project Bids and Documentation

The Company did not provide any backup if the project went out to bid other than specifying that the Company picked a contractor that met the needs of the Company. The Business Case indicates the Company selected DSI Cloud Group. This project should have gone out to bid to see if it was possible to get a better quote. **Audit Issue #5**

Audit reviewed a signed/approved 2020 Business Case for Project 8830-2083 that was for an inventory management solution as the prior Great Plains System was a cumbersome manual process with many delays, data entry, and batch processing. The delays cause inaccurate on hand balances in addition to inaccurate values posting to jobs. The Company selected DSI Cloud Inventory as the vendor for a cloud-based licensing solution that will also last with the implementation of SAP. The DSI Cloud product offers purchase order receipts, inventory put away, transfers, and cycle counting, shipping, pick, sales order slips, and numerous other advances. The Business Case indicates a 59-month license agreement that began on September 1, 2019 to July 31, 2024 for $111,805. The project was to take 1-3 years to complete. The total project was estimated to cost $136,110. The Business Case was signed/approved in January 2020 by the Project Manager up to $25,000, the Senior Director of Operations up to $250,000 and the VP of Operations up to $500,000.

Audit reviewed the January 2020 Project Capital Expenditure Form that was signed/approved by the Project Manager up to $25,000, the Senior Director of Operations up to $250,000 and the VP of Operations up to $500,000. The Company indicated they could not locate a project closeout form. The project was unitized to plant in service for $110,736. This is a $25,734 difference compared to the Project Capital Expenditure Form. **Audit Issue #5**

Retirements and Cost of Removal

There were no retirements or costs of removal for this IT project as it was a brand-new upgrade to make the inventory management function in Great Plains more useful so manual adjustments were not required.

8830-2241 Feeder Getaway Cable Replacement

Unitized in 2022 8830-2241 Feeder Getaway Cable $119,779

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 11,497
Cost Element 2-Stores and Materials	$ 2,495
Cost Element 4-Vouchers	$ 70,144
Cost Element 5-Outside Services	$ 0
Cost Element 6- Burden	$ 33,092
Cost Element 9-AFUDC	$ 1,853
Cost Element Other Direct Costs	$ 698
Total of all costs for the job:	$ 119,779
Cost Element 3-Reflects the 2020-2021 Tran to Plnt	$ (119,779) 12/1/2022

Audit reviewed the $119,779 Feeder Getaway Cable replacement installation on Spicket River Substation in Salem that was unitized to plant in service account 106 Completed Construction Non-Classified in PowerPlan on December 1, 2022.

Review of payroll, invoices, materials, and overhead support

	2022	Overheads
Contractors	$ 70,144	
Labor	$ 11,497	
Materials	$ 2,495	
Overheads	$ 33,092	27.63%
AFUDC	$ 1,853	
ODC	$ 698	
Total	**$ 119,081**	

Materials

The Company provided the journal entries from September 14, 2022 that was for six cable insulators, four splicer cable kits, and three arrestors. The transactions amounts for the thirteen items summed to $2,466. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Payroll

Audit reviewed a $43,302 bi-weekly payroll report from December 2022 that was for labor installation of the getaway cables and also any troubleshooting. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Bids and Documentation

The Company indicated they received four bids and selected the lowest priced bidder for the project.

Audit reviewed a $250,000 December 2021 Business Case that was signed/approved by the Project Lead up to $25,000, the Senior Electrical Engineering Manager up to $50,000, and the Senior Director of Electric Operations up to $250,000. The Business Case was for a Feeder Getaway Cable Replacement that was a discretionary project for the Spicket River Substation in Salem. The spending rationale for the project was this project vehicle provides faster feeder getaway cable replacements to improve and resolve reliability problems. The replacement of 300 feet of XLPE AL cables for the Spicket River 13L2 feeder getaway cable with new 1,000 Cu cables in a new underground conduit system.

Audit reviewed the December 2021 Project Capital Expenditure Form that authorized up to $250,000. The Capital Project Expenditure Form was signed/approved by the Project Lead up to $25,000, the Senior Electrical Engineering Manager up to $50,000, and the Senior Director of Electric Operations up to $250,000.

Audit reviewed an April 2023 project closeout for the 8830-2241 Feeder Getaway Replacement Project that indicates the project was budgeted for $250,000 while the project cost $122,213. This is $137,787 under budget but the close out does not give a reason for why the project is so under budget. The closeout report was signed/approved by the project leader and the Manager of Engineering Projects. The project was unitized to plant in service for $119,779 based on a review of the project by Audit. This is $2,234 difference compared to the Project Closeout actual amount spent. **Audit Issue #5**

Cost of Removal and Retirements

The Company did not provide any cost of removal or retirement entries for the getaway cable replacement projects. The Company indicated there is presently retirements backlog due to the SAP/PowerPlan system conversion in October 2022. **Audit Issue #5**

8830-2210 GSE Distributed Street Light

Unitized in 2022 8830-2210 Distributed Street Light $133,309

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 11,219
Cost Element 2-Stores and Materials	$ 39,527
Cost Element 4-Vouchers	$ 29,242
Cost Element 5-Outside Services	$ 0
Cost Element 6- Burden	$ 52,576
Cost Element 8-CIAC	$ (400)
Cost Element Other Direct Costs	$ 1,145
Total of all costs for the job:	$ 133,309
Cost Element 3-Reflects the 2022 Tran to Plnt	$ (106,555) 09/30/2022
PowerPlan Costs Unitized to Plant	$ (26,754) 12/31/2022
Total Unitized to Plant	$ (133,309)

Audit reviewed the blanket project 8830-2210 that was for the replacement of municipal streetlights. The Company began using SAP in October 2022 so as a result there were two separate journal entries for projects using the legacy WennSoft Fixed Asset System and Great Plains prior to September 30, 2022. The first entry summed to $106,555 and reflects all project costs prior to September 30, 2023. The PowerPlan entries done after summed to $26,754. The entire project with both entries summed to $133,309. The Company unitized the project to the 106 Completed Construction account and the 373 Streetlighting and Signal Systems account for $133,309.

Review of payroll, invoices, materials, and overhead support

	2020	2021	2022	Total	Overheads
Contractors	$ 3,725	$10,928	$ 14,589	$ 29,242	
Labor	$ 2,048	$ 1,839	$ 7,332	$ 11,219	
Materials		$ 6,447	$ 33,080	$ 39,527	
Overheads	$ 1,797	$ 9,552	$ 41,227	$ 52,576	39.44%
ODC			$ 1,145	$ 1,145	
CIAC			$ (400)	$ (400)	
Total	$ 7,570	$28,766	$ 96,973	**$ 133,309**	

Materials

The Company provided the August 2022 journal entry for the replacement of seven Luminaire 130W LED Street Lights. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Invoices

Audit reviewed two Granite State Cable Splicing and Testing LLC invoices. The first invoice from April 2021 was for $3,725 that was for the installation of a new foundation to new light poles, connection of the new PVC conduit, installation of mounting studs, and excavation. The June 2022 invoice was for $7,040 was for troubleshooting an outage and removing the cable feeder from the burned areas and install the new light connector. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed an April 2022 $2,391 Utility Service and Assistance, Inc. invoice that was for labor and construction equipment associated with the installation of streetlights/associated fixtures. Audit verified the hourly rates and hours worked were calculated correctly on the invoice.

Overheads

The project has a 39.44% overhead rate, and the Company provided a generic answer that overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Retirements

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $13,874 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $242. **Audit Issue #6**

Project Bids and Documentation

This project did not go out to bid because the Company used internal resources to complete the project.

There is no Business Case for this project as one is not required per the LU Capital Policy as this is a mandated blanket project. The blanket project was to provide funding for new/replacement of existing municipal lighting facilities which includes LED Conversion, install streetlight poles, replacement of streetlight bulbs, and replacement of flood lights. The Capital Project Expenditure Form authorized spending of up to $125,000. The Capital Project Expenditure Form was signed/approved by the Project Manager up to $25,000, Sr. Manager of Electrical Engineering up to $50,000, and the Sr. Director of Operations up to $250,000.

Audit reviewed the March 2023 project closeout that indicated the budgeted project cost was $125,000 while the actual project cost was $81,617. This is $43,383 under budget but the closeout report does not give a specific reason for why the project was under budgeted. The closeout was signed/approved in May 2023 by the Project Manager, the Manager of Engineering Projects, and the Sr. Director of Electric Operations. The plant in service per Audit review is $133,309. This is a $51,695 difference compared to the closeout. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal (COR) entries for the work orders tested earlier in this audit report. See the *Additions* section for review of specific COR entries. The Company debits the Accumulated Depreciation account #15030010108000 for cost of removal charges. Prior to 2020, the Company debited 8830-2-0000-20-2124-2420, Accrued Cost of Removal. Refer to **Audit Issue #6**.

The 2022 CPR records indicated the Cost of Removal charges are ($1,472,496) while the 2022 FERC Form 1 page 219 indicates ($1,563,731). This is a $91,235 difference. **Audit Issue #2**

DE 19-064 Step Adjustment Audit Reports

There were three Step Adjustment Audit reports issued since the DE 19-064 GSE rate case.

- The first step adjustment Audit Report was issued on June 30, 2020. There was one Audit issue identified in the report that indicated project 8830-1912 was overstated by $23,501 as the filing total was $1,184,186 and the GL total was $1,160,685.
- The second step adjustment Final Audit Report was issued on September 16, 2021 that identified four Audit issues related to charges that should have been booked to the 183 Preliminary Survey and Investigative Charges, Contribution in Aide of Construction (CIAC) charges that should have been removed from the final project cost, cost of removal costs that were included in the step adjustment, and pivot tables that were provided should have been more accurate. The recommended total adjustment was $647,848.
- The third and final step adjustment Audit report was issued on October 25, 2022 and there were two issues, one related to recommended project costs be removed from the filing and the second issue was related to a transformer that should not have been included because it was considered a growth project. Total recommended adjustment $1,076,831

Retirements

Audit verified the ($4,947,013) 2019-2022 retirements on page 219 of the FERC Form 1 in plant assets based on 2019-2022 $104,651,467 additions done over the same period. Audit verified the retirements to the CPR records. The Company in October 2022 unitized the SAP Enterprise Resource Planning System that allocated to GSE $13,541,670. The Company indicated they retired $6,613,191 in Legacy ERP software in February 2023. The Company indicated that the remaining $34,445 of the $6,613,191 had not been fully amortized. Audit reviewed the journal entry and calculations that were provided by GSE that included the retirements booked to the 101 account. The legacy software consisted of Cogsdale Billing System, Great Plains, WennSoft plant software, outage map enhancements, Cogsdale enhancements, and other legacy software enhancements.

Retirement Process

Retirements are processed in the PowerPlan system. The Company summarized how plant assets are retired within PowerPlan:

"*In PowerPlan, a retirement can be processed directly from the CPR (Continuing Property Records) by selecting the asset one would like to retire, associating it with a work order,* *and selecting the retirement button. This will create an entry to retire the asset from Plant in Service by crediting (101) and debiting accumulated depreciation (108). An asset can also be retired within the work order itself by creating a retirement line within the work orders as built. An as built contains a list of all items installed and removed. This results in the same entry of a credit to Plant in Service (101) and a debit to accumulated depreciation (108).*

Information is submitted by the owner of the project to the Plant Accounting department. The projects are placed in service as they are completed and the as built information outlining assets installed and removed is provided once a reconciliation of the project is complete. Retirement entries can be done in the same project in PowerPlan except for the converted 106 projects. Retirements for these projects are being done in a conversion work order as no new work order was created in PowerPlan for these."

Audit was provided the 2022 retirements that showed the retirements on the GL. The Company, in the retirement's PowerPlan PDF, books the retirement entries correctly by debiting account #108 Accumulated Depreciation and crediting the plant asset account. The Company retired ($1,116,506) in plant assets for 2022.

Accumulated Depreciation and Amortization #108, #110, #111, #115 $(123,090,712)

Audit verified the reported information seen on the FERC Form 1 to the following general ledger accounts:

15030010108000 Accrued Cost of Removal	$(8,010,584)
15501010108000 Acc Dep-Plnt in Serv	$(102,547,907)
15520010108000 Acc Dep-FC-Leg	$(1,413)
15551010108000 RWIP – Reclass	$0
15501010108100 Acc Dep-Plnt in Serv	$(188,068)
15550010108100 RWIP	$121,571
26150010108110 Long Term Cost of Removal	$(258,610)
15501010111000 Accumulated Depreciation-Plant in Service	$(12,205,701)
Total	$(123,090,712)

The account activity consisted of the monthly depreciation expenses and monthly reclassifications of expenses.

The filing schedules RR-4.1 line 2 and RR-4, line 2 reflect Accumulated Depreciation and Amortization to be ($123,210,870) while the FERC Form 1 has a 2022 ending balance of $(123,090,712). This is a ($120,158) variance that is the result of the filing schedule not including the ($1,413) booked to account 15520010108000 Acc Dep-FC-Leg and $121,571 booked to the Retirement Work In Process account 1555001010810. These were not included on the filing schedule reportedly due to a coding issue. The CPR records indicated the December 31, 2022 Accumulated Depreciation summed to $123,180,534 while the Accumulated Depreciation per the GL summed to $123,090,712. This is an $89,822 difference. **Audit Issue #2**

Depreciation and Amortization Expense

Depreciation Expense, Amortization of Intangibles, and Amortization of Regulatory Debits were combined within the filing on schedule RR-2.12 line 12 for a total of $10,720,302.

55051010403000 Depreciation Expense	$10,403,054	
55056010403000 Capitalized Depreciation- Equipment	($52,491)	
55057010403000 Capitalized Depreciation-Fleet	$79,367	
Total 403 Depreciation Expense 2022	$10,429,931	FERC F1 pg. 114 line 6
55051010404000 Amortization of Property Plant and Equip.	$435,976	
55001010405000 Amortization of Intangible Software	$93,402	
Total 404 and 405 accounts for 2022	$529,378	FERC F1 pg. 114 line 8
55021010407300 Amortization of Rate Base Offset	$144,128	FERC F1 pg. 114 ln 12
Total 403-407 Dep. And Amort. Expense accounts	$11,103,407	
40033010407300 Other Electric Revenue	($383,135)	**Audit Issue #1**
Total	$10,720,302	

Audit reviewed and tested individual plant in service depreciation transactions in the CPR to the most recent approved deprecation Study in DE 19-064. Audit was able to verify the 2022 Depreciation Expense totals on the CPR records to the GL and filing schedules that summed to $10,403,054. The CPR records indicated the December 31, 2022 Accumulated Depreciation summed to $123,180,534 while the Accumulated Depreciation while the GL summed to $123,090,712 and Filing Schedule RR-4.1 line 2 and RR-4, line 2 reflected 123,210,870.

The net $26,876 capitalized fleet/equipment overhead represents the capitalized monthly fleet, allocated on a pro-rata basis. **Audit Issue #3**

Both the $10,429,931 depreciation expense and the $529,378 Amortization of Intangible Software are offset to the Accumulated Provision for Depreciation of Electric Utility Plant account 155010108000. The Regulatory Debit Amortization was offset to the 10182300 Other Regulatory Asset Deferred Rate Case account. Audit verified the $529,378 in 2022 amortization of intangible software to the GL that were authorized for recovery as part of Commission Order 26,376 that approved the DE 19-084 GSE 2018 rate case settlement agreement. Audit reviewed and verified the $435,975 monthly deprecation calculations provided by the Company. Audit review and verified the $93,405 intangible plant software calculations that were provided by the Company. The 26,376 Order indicates the original 405 reserve balance was $1,950,390 to be amortized over a 6 year period or $325,065 per year.

The full $144,128 Amortization of Regulatory Debits is included on Filing Schedule RR-2.12. These are the amortized rate base associated with the 2018 rate case expenses that were approved for recovery in Commission Order 26,376 on June 30, 2020 that approved the DE 19-064 Settlement Agreement. The Company during 2022 amortized $24,021 monthly or $144,128 from January-June 2022. The monthly 407 entries were offset to the LTRA Rate Base Offset account 17120010182300 and the 17120010186000.

The ($383,135) Other Electric Revenue were miscoded to the GL account 10407300 related to revenue balances, that included certain charges billed to customers through the CIS system. There were also some manual adjustments for unbilled revenue as of December 31, 2022. Please see the *Revenue section* for more detailed information on this account. The amount was proformed out of the RR-2.12, but not into the revenue schedule. **Audit Issue #1**

Construction Work in Progress (CWIP) #107 $15,266,206

The filing revenue requirement schedules did not include the CWIP account. The FERC Form 1 balance for CWIP is $15,266,206 while the 15010010107000 SAP GL account summed to $15,258,393. This is a $7,813 difference the Company indicated was the result of adjustments that were identified during the preparation of the 2022 FERC Form 1. GSE indicated certain transactions were mis-mapped at conversion from Great Plains to SAP **Audit Issue #1**

Total 107 account balance per 2022 SAP GL	$15,258,393
Total 107 account balance per FERC Form 1	$15,266,206
Variance	$ (7,813)

GL Account	Amount	Notes
50211010921000	$14,040	Exclude from 921 Office Supplies Expense add to 107
50500010107000	($5,264)	Add to 920 Other Operating Expenses-Exclude from 107
70200010107000	($962)	Add to 920 acct-Exclude from the 107 account
Total	$7,813	Total Adjustments/variance **Audit Issue #1**

Allowance for Funds Used During Construction (AFUDC)

Audit verified the AFUDC to:

47040010419100 AFUDC Equity	$(130,600)	FERC pg. 117 line 38
56201010432000 AFUDC Borrowed	$(79,309)	FERC pg. 117 line 69

Activity within both accounts was offset to the Construction Work in Process account 15010010107000. See review of individual work order in the Plant selections above for review of individual AFUDC detail.

Materials and Supplies #154 $3,759,408

The total per the filing schedule RR-4 line 6 and RR-4.2 agrees with the three SAP general ledger regulatory account 1540 and the FERC Form 1 page 110 line 48.

Account #	Amount
12100010154000	$4,259,944.41
12100510154000	($501,826.54)
12101510154000	$1,290.56
Total	$3,759,408.43

The reported FERC Form 1 balance since the prior rate case (test year ended 12/2022) reflects:

2019	2020	2021	2022
$2,950,132	$2,538,074	$2,400,315	$3,759,408

The Company, in the response to DOE Staff Data Request 4-8, provided 2020-2022 Historical Stock Status Detailed Inventory Reports. The attachments DOE 4-8-1 and 4-8-2 indicate the December 2022 Historical Stock balance is $4,259,944 while the GL accounts summed to $3,759,408. This is a ($500,536). **Audit Issue #7**

Additional material details are discussed in the review of individual projects in the *plant* section of this report.

Audit verified that the Great Plains 9/30/2022 ending balance of account 8830-2-0000-10-1380-1540, $4,034,239.53 was rolled into the SAP account 12100010154000.

Stores Expense #163 $0

The Stores Expense Undistributed account on the 2022 FERC Form 1 balance sheet, line 54 is zero. Audit reviewed the 1630 SAP general ledger account, which is the sum of six accounts totaling $54,509. As previously noted, the Company stated that the Stores Expense accounts were mapped incorrectly to account 163, and are included within expense account 920, Administrative and General Salaries on the FERC Form 1. **Audit Issue #1**

GL	G/L Account2	Regulatory Acc	GL - REG		Dec-22
121070	Stores Exp Undstrb	1630	12107010163000	$	-
500000	Salaries and Wages	1630	50000010163000	$	2,388
500300	Outside Svs	1630	50030010163000	$	33
500500	Equip & Machin Rents	1630	50050010163000	$	12,039
505000	Other Operating Exp	1630	50500010163000	$	4,383
800000	Lbr Alloc	1630	80000010163000	$	35,666
				$	54,509

Prior DE 19-064 Audit Report

Within the prior audit report, Audit Issue #4 identified $5,265 in artwork that was included in Plant in Service, in account #398, Miscellaneous Equipment. Audit had recommended that the amount be excluded from Plant in Service since it is not necessary for the safe and reliable provision of electrical service. The Company disagreed. Audit reviewed the continuing property records, and noted that the asset remains within the account #398. A**udit Issue #27**

CURRENT and Other ASSETS

Cash - $43,270,870

Audit noted the year-end general ledger cash totals on the FERC Form 1, page 110-111, lines 35 and 36 respectively:

Cash account 131	$43,238,110
Special Deposits account 134	$ 32,759
	$43,270,870 rounded

Audit verified the September ending balance to the following GP accounts:

8830-2-0000-10-1020-1310 Cash-JP Morgan	$(289,661.64)
8830-2-0000-10-1060-1340 Other Special Deposits	$ 32,455.93
Cash per the GP General Ledger 9/30/22	$(257,205.71)

Audit then verified that the September balances were rolled into the SAP general ledger system. Schedule 1604.01(a)(1)(a)BS, Bates page I-006 reflects a total December 2022 cash figure of $43,238,109.80. The following SAP accounts mapped to Cash 1310 sum to $43,238,110.63 which is $0.83 higher than the filing. As noted, that is a mismatch of account 52001010131000, Elec Pur Power Misc. Also included in the total for both the filing and the FERC Form 1 is account 24080010131000, CRL Fuel&Commod Cost $(7,031.50) and account 52001010131000 $0.83 which is also a result of the mapping issue when Great Plains merged into SAP. **Audit Issue #1**

Company Code	GL	G/L Account2	Regulatory	GL-Reg	Sep Balance	Oct Balance	Nov Balance	Dec Balance
3071	100110	Bank 1-CIB Main	1310	10011010131000	$ (289,661.64)	$ -	$ -	$ -
3071	100114	Bank 1- Clrg-MAR	1310	10011410131000	$ -	$ (10,931.00)	$ (79,139.59)	$ (6,028.49)
3071	100115	Bank 1- Clrg-CIS	1310	10011510131000	$ -	$ (3,054.60)	$ (3,054.60)	$ (3,054.60)
3071	100117	Bank 1- Clrg-Sweep	1310	10011710131000	$ -	$ -	$ -	$ 816,314.55
3071	100118	Bank 1- Clrg-ICO/FT	1310	10011810131000	$ -	$ (902,969.92)	$ (203,318,602.22)	$ 42,440,286.50
3071	100119	Bank 1-Clrg-Other	1310	10011910131000	$ -	$ (289,661.64)	$ 402.77	$ (2,376.66)
3071	240800	CRL Fuel&Commod Cost	1310	24080010131000	$ -	$ (7,031.50)	$ (7,031.50)	$ (7,031.50)
3071	520010	Elec Pur Power Misc	1310	52001010131000	$ -	$ 0.83	$ 0.83	$ 0.83
					$ (289,661.64)	$ (1,213,647.83)	$ (203,407,424.31)	**$ 43,238,110.63**
3071	188010	Restricted Cash	1340	18801010134000	$ 32,455.93	$ 32,541.36	$ 32,637.41	**$ 32,759.31**
								$ 43,270,869.94

The BlackRock mutual fund is noted in the Other Special Deposits account above.

Audit attempted to verify the general ledger amounts to a cash reconciliation, however the reconciliations provided by Company did not reconcile with a noted ($210,283,306.62) discrepancy between the reconciliation listing of general ledger account balances and the actual 12/31/2022 general ledger. Regarding the large discrepancy, the Company stated: "*An additional entry was posted after the reconciliation was completed as part of our parking lot entry process. G/L account 100118 is used for intercompany cash transfers and accruals*". The discrepancies are noted below. **Audit Issue #8**

GL	G/L Account2	GL - REG	GL Balance 12/31/22	Cash Reconciliation	Difference
100110	Bank 1-CIB-Main	10011010131000	**$ -**	$ -	
100114	Bank 1-Clrg-MAR	10011410131000	**$ (6,028.49)**	$ (6,028.49)	$ -
100115	Bank 1-Clrg-CIS	10011510131000	**$ (3,054.60)**	$ (3,054.60)	$ -
100117	Bank 1-Clrg-Sweep	10011710131000	**$ 816,314.55**	$ 816,314.55	$ -
100118	Bank 1-Clrg-ICO/FT	10011810131000	**$ 42,440,286.50**	$ (167,843,019.29)	$ 210,283,305.79
100119	Bank 1-Clrg-Other	10011910131000	**$ (2,376.66)**	$ (2,376.66)	$ -
240800	CRL Fuel&Commod Cost	24080010131000	**$ (7,031.50)**	$ (7,031.50)	$ -
520010	Elec Pur Power Misc	52001010131000	**$ 0.83**	$ -	$ 0.83
			$ 43,238,110.63	$ (167,045,195.99)	$ 210,283,306.62

Audit reviewed the bank statement associated with the accounts below and notes that the difference between the bank statement and reconciliation is identified as "known":

December 2022 Cash Reconciliation							
Balance per General Ledger	$	(167,038,164.49)					
Balance per JP Morgan Chase Bank Statement	$	-					
variance	$	(167,038,164.49)					
				Actual			
Explanation of Known variance:				**SAP 12/31/2022**		**SAP vs. Recon**	
1. GL 100111: ACH Clearing	$	-	$	-	$	-	
2. GL 100112: Check Clearing	$	-	$	-	$	-	
3. GL 100113: Wire Clearing	$	-	$	-	$	-	
4. GL 100114: Misc AR Clearing	$	(6,028.49)	$	(6,028.49)	$	-	
5. GL 100115: CIS Clearing	$	(3,054.60)	$	(3,054.60)	$	-	
6. GL 100116: CIS Other Clearing	$	-	$	-	$	-	
7. GL 100117: Sweep Clearing	$	816,314.55	$	816,314.55	$	-	
8. GL 100118: Inter-Co Clearing	***$***	***(167,843,019.29)***	***$***	***42,440,286.50***	***$***	***210,283,305.79***	
9. GL 100119: Other Clearing	$	(2,376.66)	$	(2,376.66)	$	-	
Known variance	$	(167,038,164.49)	$	43,245,141.30	$	210,283,305.79	
Unreconciled variance	$	-					

Audit was also provided the bank statement related to account 24080010131000, CRL Fuel&Commod Cost $(7,031.50) which is part of a larger liability account and found no variances between the reconciliation and the bank statement.

A notation on the reconciliation indicates that the 1310 general ledger account is used primarily to record receivables from customers for Granite State Electric.

Per the Company, the BlackRock account complies with the ISO-NE financial assurance requirement in the Open Access Transmission Tariff. Audit reviewed the statement and reconciliation without exception. Both accurately reflect the general ledger balance noted above.

Interest earned on the BlackRock account is reinvested, and the debits were noted in the 1340 account and the credits posted to 8830-2-0000-40-4420-4190, Interest Income. The SAP account shows the debits to the 134 account (account #3071-10167-188010-10134000) and credits posted to 3071-10167-1016795000-470300-10419000 The reinvested income was noted on the December 31, 2022 BlackRock statement. The total for the year is $32,759.31.

Audit reviewed the current irrevocable standby letter of credit, in the amount of $7,000,000, which expires on 11/30/2023. The letter was issued by Canadian Imperial Bank of Commerce on behalf of Algonquin Power & Utilities Corp. on behalf of Liberty Utilities (Granite State Electric) Corp. in favor of ISO New England, Inc. The standby letter of credit is a contingent liability, thus not reflected on the general ledger of GSE.

The reported FERC Form 1 Cash and Other Special Deposit balances since the prior rate case reflect:

	2019	2020	2021	2022
Cash	$ 19,277.00	$ 61,625.00	$ (2,074.00)	$ 43,238,110.00
Black Rock	$ 26,962.00	$ 227,162.00	$ 5,227,213.00	$ 32,759.00

Accounts Receivable #142 $29,736,311.52

The FERC Form 1 and filing schedule 1604.01, Bates page I-006 reflect the above receivable figure. Audit verified the total to the following general ledger accounts, demonstrating the September 2022 ending balance of the Great Plains system, then the month end totals for October, November, and December 2022 per the SAP system:

G/L Account2	Regulatory	GL - REG	SEP Balance	OCT Balance	NOV Balance	DEC Balance
Customer AR-CIS-Ctrl	1420	11001010142000	$ 15,258,152.10	$ 14,950,774.81	$ 16,044,560.09	$ 19,227,997.79
Cst AR-Mnl	1420	11001210142000	$ (35,563.58)	$ 737,519.85	$ 678,919.48	$ 939,928.12
Cst AR-Mktr-NONPOR	1420	11001810142000	$ 1,123,066.39	$ 1,018,451.91	$ 1,334,651.71	$ 1,435,730.60
Cst AR (NonCIS)-Ctrl	1420	11002010142000	$ 1,725,743.42	$ 1,774,718.37	$ 1,728,632.97	$ 1,701,770.06
Cst AR (NonCIS)-Mnl	1420	11002110142000	$ -	$ -	$ -	$ (45,013.51)
AR-Legacy	1420	11003010142000	$ 3,297,343.22	$ 2,554,212.13	$ 2,511,255.15	$ (419,065.52)
CRA Fuel&Commod Cost	1420	13080010142000	$ 5,803,468.97	$ 2,627,374.31	$ 2,627,374.31	$ (1,048,436.69)
CRA Fuel&Commod Cost	1420	13080010142001	$ -	$ (3,093,089.25)	$ (423,018.59)	$ 7,943,400.67
CRA R8 Adj Mech	1420	13110010142000	$ -	$ -	$ -	$ -
			$ 27,172,210.52	$ 20,569,962.13	$ 24,502,375.12	**$ 29,736,311.52**
			Great Plains	SAP	SAP	SAP

Audit verified the September ending balance to the GP accounts:

8830-2-0000-10-1101-1420 Customer Accounts Receivable	$19,688,011.64
8830-2-0000-10-1101-1421 Customer AR-Misc Billing	$ 1,680,729.91
8830-2-0000-10-1101-1423 A/R Under Collect-Default/LR Sv	$ 2,127,657.97
8830-2-0000-10-1101-1429 A/R REC Obligation	$ 3,675,811.00
Account 142 as of 9/30/2022	$27,172,210.52

The aged accounts receivable listing as of 12/31/2022 includes 44,826 customers and sums to $21,567,622.35. The aging details demonstrate:

Age	# of customers	Total Receivable
Current	40,053	$13,650,488.48
Past due 1-30 days	10,417	$ 2,739,656.85
Past due 31-60 days	6,409	$ 1,698,694.95
Past due 61-90 days	3,872	$ 934,855.91
Past due 91-120 days	3,194	$ 1,317,646.29
Past due 121-150 days	2,624	$ 200,970.90
Past due 151-365 days	2,073	$ 591,219.46
Past due over 365 days	858	$ 466,146.87
	69,500	$21,599,679.71

Audit was unable to tie the aged accounts receivable listing to any account within the general ledger. When asked, Liberty noted that the "*aged trial balance report did not tie out exactly to the general ledger, but it was determined that the variance was immaterial. We have since developed additional reports to clarify differences (mostly due to timing), but these reports* *were not available in December 2022.*" Audit was then provided with a reconciliation without explanation.

AR Debit balances	$19,814,926.03
AR Credit balances (aka Unapplied Payments)	$ (609,186.12)
Total AR	$19,205,739.91

A different portion of the reconciliation reflected Total AR of $19,212,094.38 which was calculated to reflect a variance from the reported $19,205,739.91 of $6,354.47 or 0.03%. While Audit agrees that a percentage variance of 0.03% is immaterial, none of the components within the reconciliation could be verified to the general ledger provided to Audit. **Audit Issue #9**

Refer to the *Unapplied Payments* portion of this report, account 242.

Audit also noted four additional SAP Accounts Receivable accounts that were not included within the #142 figure above:

Salaries and Wages	1420	50000010142000	$ 2,472.80
Other Operating Exp	1420	50500010142000	$ -0-
BS LB Offset	1420	70200010142000	$(13,353.12)
WBS ST Lbr-Intrc	1420	85400010142000	$ 29,179.04
			$ 18,298.72

In response to clarification regarding these four accounts, the Company noted that at the set-up of the SAP, the accounts to which these specific accounts' transactions would "settle" were miscoded to the Accounts Receivable. Each was reported to have settled to FERC account 920. Refer to the *Operations and Maintenance* portion of this report. **Audit Issue #1**

Other Accounts Receivable #143 $699,313.90

Audit verified the 12/31/2022 balance on the FERC Form 1 to the following SAP accounts:

Other AR	1430	11303010143000	$ 872,782.97 no change 9/22 – 12/22
Ener Eff Loan Rec	1430	11303510143000	$ 841,012.93
Inc Tax Receivable	1430	14601010143000	$(1,014,482.00) Refer to *Tax* section
			$ 699,313.90

Accounts Receivable from Associated Companies $964,071,909

Filed schedule 1604.01(a)(1)(a) BS reported the above listed total. The following represents the general ledger account balances, as of 12/31/2022:

Interco AR	11101010146000	$ 391,133,658
Interco AR - Legacy	11102010146000	$ 572,938,250
Total (rounded)		$ 964,071,909

The filed total was verified to the FERC Form 1 in that the AR from Associated companies balance was netted with the AP to Associated Companies:

	FERC Form 1	SAP	Variance
Account #146	$ -0-	$ 964,071,908.63	$(964,071,908.63)
Account #234	$(75,125,573.00)	$(1,039,197,481.56)	$ 964,071,908.56
		$ (75,125,573.93)	

Audit noted that the filed schedule reflected an overall balance sheet that included a $(75,125,573.93) variance. For details regarding the variances between the FERC Form 1 balance sheet accounts, refer to **Audit Issue #1.**

The general ledger account balances included in the total filed amount of $964,071,909 were from the intercompany accounts used to record the daily intercompany receivable entries. These receivable entries, such as the cash from customers, are received at the Service Company level—which the Company explained is a separate entity in their accounting system. The AR balance is cleared through an intercompany entry between Granite State and the Service Company. Audit confirmed the that entries to record customer billings were offset to account 11001010142000, Customer AR CIS Ctrl. Refer to the *Accounts Payable to Associated Companies* section of the report for details regarding the GP account settlement of intercompany activity.

Prepayments Account #165 $1,384,677

The filing schedules RR-4.1 and RR-4.2 reflect the total prepayments figure of $1,915,251 as of 12/31/2022. The FERC Form 1 reflects $1,384,677.

Audit verified the September 2022 balances to two general ledger accounts:

8830-2-0000-10-1240-1650 Prepaids	$ 81,450.02
8830-2-0000-10-1240-1653 Prepaid Taxes-Mun-Property-Oper	$736,912.87
Balances as of 9/30/2022	$818,362.89

Each account balance was rolled into SAP accounts 14090010165000, Other Prepaids, and 14081010165000, Prepaid Property Tax. At year end, the balances were:

14090010165000, Other Prepaids	$ 107,887.91
14081010165000, Prepaid Property Tax	$1,276,788.72
Total Prepaids	$1,384,676.63

The 1604.01(a)(1)(a)BS, Bates page I-007 does accurately reflect the prepaid account 165 to be $1,384,676.63.

The variance of $530,574 between the FERC Form 1 and RR-4.1 and RR-4.2 was reported to be SAP accounts, originally mismapped to account 184, but reflected in account 165 on the filing

14023010184000 Billable Interco Clg	$129,595	
14024010184000 Billable Clg	$398,803	
14025010184000 P Card Clearing	$ 2,176	
	$530,574	**Audit Issue #1**

The FERC Form 1 shows a total Clearing Account balance in account #184 of $1,052,518, which is the sum of 7 specific SAP accounts. SAP reflected an additional 33 accounts that sum to $89,572.70, all of which were identified by the Company to have been excluded from account 184 on the FERC Form 1 and included within expense account 920, Administrative and General Salaries. **Audit Issue #1**

DOE Staff requested, in Data Request 4-7, for a list of prepayments and balances by month by major category. The following shows a high level summary from the Company's response to Date Request 4-7.

Total Software	$ 107,889.00
Taxes	$ 1,276,788.72
Clearing Account Entries	$ 530,573.99
Reconciling Items to RR-4.2	$ (1.09)
Total	$ 1,915,250.62

In their response to the Data Request, Liberty noted a minor difference of $1,255 between filing Schedule RR-4.2 and the detailed data. The Company noted they will consider this in their next update of the revenue requirement.

Unamortized Debt Expense Account #181 $14,655

The 2022 Unamortized Debt Expense totaled $14,655 on the FERC Form 1, as well as on the filed schedule 1604.01(a)(1)(a) BS. The amount was verified to the following general ledger account balances, as of 12/31/2022:

Account	Description	Balance
18922010181000	Interco Dfrd Fin	$ 11,447.72
18914010181000	Unamort Debt Exp	$ 3,207.75
	Total Unamortized Debt Exp	$ 14,655.47

The account 1892201081000 was mapped from GP account 8830-2-0000-10-1936-1000, Deferred Financing-Intercompany. Audit confirmed that the GP September balance of $12,592.52 rolled into SAP account 1892201081000. There were no journal entries recorded on the GP account between January – September 2022 and Audit verified that the $12,592.52 reflected the beginning balance forward. On the SAP account there were three monthly credit entries of $95.40 during October – December for the intercompany deferred financing, as well as one debit entry of $11,733.92. The debit was for the reclassification—from account 18922010186000, Misc Deferred Debits—for the monthly deferred financing from January – September 2022 that should have been booked to the deferred financing intercompany GP account. Refer to the ***Interest on Debt to Associated Companies*** section of the report for details regarding the intercompany deferred financing.

The account 18914010181000 was mapped from GP account 8830-2-0000-10-1931-1810, Unamortized Debt Expense. Audit confirmed that the GP September balance of $3,862.53 rolled into SAP account 18914010181000. There were monthly credit entries on the account that were associated with obtaining the First Colony Bonds. Offsetting debit entries were booked to GP account 8830-2-0000-80-8541-4280, Amortize Debt Discount and Expense, which was mapped to SAP account 56104010428000, Amrt Fn Cst-Debt Dis. Refer to the *Long Term Debt* and *Amortization of Debt Discount and Expense* sections for further details.

Other Regulatory Assets $4,557,561

The 2022 FERC Form 1 reflects total Other Regulatory Assets in account 182.3 as $4,557,561. The SAP 12/31/2022 1823 accounts sum to $5,813,867.39. Audit requested clarification of the variance of $(1,256,306.39) and was informed of the SAP set-up settlement issue described earlier. **Audit Issue #1**

3071 LU Granite State Electric OCOA/13010 130100	CRA-Pnsn&PostEmp Ber	1823	13010010182300	$ 2,056,720.25	
3071 LU Granite State Electric OCOA/13080 130800	CRA Fuel&Commod Cos	1823	13080010182300	$ (3,582,940.43)	
3071 LU Granite State Electric OCOA/13110 131100	CRA R8 Adj Mech	1823	13110010182300	$ 3,273,667.00	
3071 LU Granite State Electric OCOA/13160 131600	CRA Oth Reg Ast	1823	13160010182300	$ 110,538.53	
3071 LU Granite State Electric OCOA/13160 131600	CRA Oth Reg Ast	1823	13160010182302	$ 164,689.52	
3071 LU Granite State Electric OCOA/17010 170100	LTRA Pen&PostEmp Ber	1823	17010010182300	$ 1,669,609.39	
3071 LU Granite State Electric OCOA/17090 170900	LTRA Inc Tax	1823	17090010182300	$ 518,774.83	
3071 LU Granite State Electric OCOA/17110 171100	LTRA Adj Mech	1823	17110010182300	$ -	
3071 LU Granite State Electric OCOA/17120 171200	LTRA R8 Case Cost	1823	17120010182300	$ 22,127.50	
3071 LU Granite State Electric OCOA/17150 171500	LTRA Storm Cost	1823	17150010182300	$ -	
3071 LU Granite State Electric OCOA/17160 171600	LTRA Cost of Rem	1823	17160010182300	$ -	
3071 LU Granite State Electric OCOA/17170 171700	LTRA Oth Reg Ast	1823	17170010182300	$ 158,512.72	
3071 LU Granite State Electric OCOA/24080 240800	CRL Fuel&Commod Cos	1823	24080010182300	$ 833,043.45	exclude in full from 182.3, included with 254 on FERC Form 1
3071 LU Granite State Electric OCOA/50000 500000	Salaries and Wages	1823	50000010182300	$ 884,954.96	exclude ($1,081.00) from 182.3, include in 920
3071 LU Granite State Electric OCOA/50030 500300	Outside Svs	1823	50030010182300	$ 126,253.43	exclude ($1,411.98), $53,144.70, $37,141.25, and include in 920
3071 LU Granite State Electric OCOA/50123 501230	Fleet-Permit/Inspect	1823	50123010182300	$ 25,839.23	
3071 LU Granite State Electric OCOA/50500 505000	Other Operating Exp	1823	50500010182300	$ 174,587.70	exclude $2,380.00 from 182.3, include in 920
3071 LU Granite State Electric OCOA/70200 702000	BS Lbr Offset	1823	70200010182300	$ (886,035.96)	
3071 LU Granite State Electric OCOA/70203 702030	BS Services Offset	1823	70203010182300	$ (37,379.46)	
3071 LU Granite State Electric OCOA/70204 702040	BS Other Offset	1823	70204010182300	$ 326,743.96	
3071 LU Granite State Electric OCOA/70205 702050	BS Fleet Offset	1823	70205010182300	$ (25,839.23)	
				$ 5,813,867.39	
included in acct 254 on FERC			24080010182300	$ (833,043.45)	
included in acct 920 on FERC			50000010182300	$ 1,081.00	
included in acct 920 on FERC			50030010182300	$ 1,411.98	
included in acct 920 on FERC			50030010182300	$ (53,144.70)	
included in acct 920 on FERC			50030010182300	$ (37,141.25)	
			50500010182300	$ (2,380.00)	
Additional accounts to include in 182.3 balance:					
LTRA R8 Case Cost		**186**	**17120010186000**	$ 165,861.82	removed from account 186
Cost Alloc to Cap		**922**	**50510010922000**	$ (316,613.20)	removed from account 922
Cost Alloc to Cap		**922**	**50510010922000**	$ (182,338.46)	removed from account 922
		FERC pdf pg 26 line 72		**$ 4,557,561.13**	

Preliminary Survey and Investigative Charges Account #183 $310,019

Audit verified the $310,019.47 Preliminary Survey and Investigative balance on line 73 of the 2022 FERC Form 1 balance sheet to SAP regulatory general ledger accounts 10183000:

Account #	Account Name	Amount
15050010183000	Facility Costs	$ -0-
18980210183000	Prelim. Survey and Invest. Charges	$310,019
50030010183000	Outside Services	$ 37,500
70203010183000	BS Services Offset	$ (37,500)
	Total	$310,019

There were no Preliminary Survey and Investigative charges included on the revenue requirement filing schedules. The GP account 8830-2-0000-10-1615-1830 had a September 30, 2022 balance of $272,519 which was rolled into the SAP account 18980210183000. The GL activity consisted of investigation of new facility costs that rolled from the Great Plains system into the 18980210183000 SAP account. The 15050010183000 Facility Costs account did not have any activity.

The Company indicated there are two settlement accounts that always net to zero: the Outside Services account 50030010183000 go through a settlement and the Outside Services Offset account 70203010183000 creates a credit. The final posting of settlement accounts is then reflected in the 18980210183000 Preliminary Survey and Investigative Charges account. Audit sampled a $37,500 Burns and McDonnell Engineering Company September 30, 2022 invoice that was part of the settlement charges and finally moved to the 18980210183000 account on December 31, 2022. The charges on the invoice were for the contract award, construction analysis, buildout plan, and issuance of final report. The Company indicated that the project will be completed in 2023 construction year.

Accrued Revenues #173 $3,002,394

Audit verified the FERC Form 1 balance sheet Accrued Revenue figure to SAP account 11010010173000, Unbilled Revenue.

The roll forward of Great Plains account 8830-2-0000-10-1162-1730, Accrued Utility Revenue, $1,748,164.16 was noted in the SAP account above. Refer to the ***Revenue*** section of this report for additional information.

Deferred Assets-Storm #1825 $-0-

Great Plains general ledger account 8830-2-0000-10-1930-1825, Storm Costs at 9/30/2022 was $1,604,126.08. Audit verified that that figure was rolled into SAP account 17150010182300, which was zeroed by year-end. This account is part of an annual rate review and audit, and was not reviewed as part of this rate case audit. The 2022 Storm Cost audit report, in docket DE 23-035, was issued on August 17, 2023.

Equity $(147,811,392) and Liabilities $(32,000,000)

The following depicts filed schedule 1604.01 and the FERC Form 1 totals for the Capital:

Account Description		Per 1604.01		Per FERC Form 1
Common Stock	$	(99,024,903)	$	(6,040,000)
Other Paid-in Capital		-		(92,984,903)
Retained Earnings		(45,528,745)		(44,680,599)
Accumulated Other Comprehensive Income		(3,257,744)		(3,257,743)
Total Proprietary Capital	$	(147,811,392)	$	(146,963,245)

Audit noted a variance of $848,147 in the total proprietary capital, as reported on the filed schedule 1604.01 and the FERC Form 1. The variance resulted from the retained earnings filed of $(45,528,745) on schedule 1604.01 versus the retained earnings reported of $(44,680,599) on the FERC Form 1. The Company confirmed that, *"The capitalization per the 1604.01(a)(1)(b) BS includes the 2022 Net Income per the 1604.01(a)(1)(b) IS which was prepared prior to the adjustments to correct for incorrect regulatory accounts and unsettled WBS transactions."* Refer to the Retained Earnings $(45,528,745) section of the report for further details regarding the variance.

The capitalization was verified to the following general ledger accounts:

SAP GL Account	Account Description		12/31/22 Balance
31010010201000	Common Shares	$	(82,024,903)
33500010211000	Additional Paid-in Capital		(17,000,000)
34100010216000	Retained Earnings		(32,931,729)
Net activity all revenue and expense accounts 2022			(11,748,870)
		$	(143,705,501)
36201010219000	AOCI Pension Tax	$	(1,351,471)
36203010219000	AOCI-OPEB Tax		906,817
36204010219000	AOCI-Pension		4,260,428
36206010219000	OCI Pension FAS 158		(2,757,297)
36207010219000	AOCI OPEB		(2,613,808)
36208010219000	AOCI OPEB FAS 158		(3,347,404)
36209010219000	OCI Pension Tax		1,644,991
	Adjustment to Retained Earnings	$	(3,257,744)
	General Ledger Total Capitalization	$	(146,963,245)

Common Stock $(99,024,903)

The filing schedule 1604.01 reported the Common Stock total of $(99,024,903), as of December 31, 2022. The amount was verified to the FERC Form 1 for the total Common Stock Issued $(6,040,000) and Other Paid-in Capital $(92,984,903). Audit understands that—for presentation purposes on the FERC Form 1 only—the Company depicted a consolidated Other Paid-in Capital $(92,984,903), as represented by the following general ledger account balances, less the par value $6,040,000 of Common Stock: account 310100, Common Stock $(82,024,903) and account 335000, additional Paid-in Capital $(17,000,000). As at December 31, 2022, there were 60,400 common shares issued and outstanding. One hundred percent of the authorized issuance of common shares is owned by Liberty Energy Utilities (New Hampshire) Corp. with a par value of $100.00 per share. Audit verified that the reported common stock of $(6,040,000) and other paid-in capital of $(92,984,903) has not changed since the 2018 test-year audit, docketed as DE 19-064.

Other Paid-in Capital $0

There was no amount reported on the filed schedule 1604.01 for Other Paid-in Capital. The FERC Form 1, line 7, reported the figure as $(92,984,903). The 12/31/2022 balance on the general ledger for SAP account 335000-10211000, Additional Paid-in Capital, totaled $(17,000,000). Audit noted that the general ledger balance has not changed since the 2018 test-year audit, docketed as DE 19-064. Refer to the *Common Stock $(99,024,903)* section of the report for details regarding the filed balance for the paid-in capital versus the general ledger and FERC Form 1.

Retained Earnings $(45,528,745)

The filed schedule 1604.01 listed the total Retained Earnings as $(45,528,745). The FERC Form 1 reported a 12/31/2022 retained earnings balance of $(44,680,599). Audit noted the $848,146 variance between the retained earnings filed and the FERC Form 1. The Company explained that *"The variance of $848,146 in the retained earnings balance is due to the variance in the Net Income reported on the FERC Form 1, Page 117, line 78 and the filed 1604.01 (a)(1)(a) PL, page 2 of 2, which is carried forward to retained earnings. These differences are the result of corrections identified in the preparation of the FERC Form 1 after our parent company's annual report was issued. Through discussions with our external auditors, it was determined that the FERC Form 1 would remain consistent with the results included in the APUC annual report. The 1604.01 (a)(1)(a) PL was updated to reflect the correct results for those items identified."*

The Retained Earnings adjustment of $(3,257,744) was verified to the SAP general ledger accounts for the Accumulated Other Comprehensive Income (AOCI). Refer to the *Equity and Liabilities* section of the report for details.

Audit reviewed the activity in each of the AOCI accounts for the test year 2022. Adjustments were reported to be based on actuarial reports, amortization expenses for pension and OPEB, pension true up and tax entries—as well as entries for the GP balance reclass to SAP account 10219000. Additional information relating to pension and OPEB are included within the Payroll section of this report.

Long-Term Debt $(32,000,000)

The filed schedules RR-5.1 and 1604.01 each reported the total long-term debt balance of $(32,000,000), which was confirmed to the FERC Form 1. The following represents the FERC Form 1 balances for the Company's long-term debt obligation, as reported since the prior rate case for the test-year 2018:

Account	Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022
223	Advances from Associated Companies	$ (17,000,000)	$ (17,000,000)	$ (17,000,000)	$ (17,000,000)
224	Other Long-term Debt	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)
	Total Long-Term Debt	$ (32,000,000)	$ (32,000,000)	$ (32,000,000)	$ (32,000,000)

Advances from Associated Companies #223 $(17,000,000)

Filed schedule RR-5.1 detailed the Company's reported $17,000,000 of outstanding promissory notes payable to Liberty Utilities, as of 12/31/2022:

Date Issued	Maturity	Rate	Principal	Annual Interest
12/21/12	12/20/27	4.89%	$ 1,545,455	$ 75,573
12/21/12	12/20/27	4.89%	$ 4,121,212	$ 201,527
12/21/12	12/20/23	4.49%	$ 7,898,990	$ 354,665
12/20/17	12/20/32	4.22%	$ 3,434,343	$ 144,929
			$ 17,000,000	$ 776,694

The outstanding balance of $(17,000,000) was verified to SAP general ledger account 25100010223000, Notes P-Intrco Leg. Audit recalculated the interest rate for each of the four notes payable and verified the annual intercompany interest amount of $776,694 that was paid on long-term debt during the test-year 2022. Audit confirmed that the annual interest expense was debited as monthly journal entries of $64,724.49 on the GP interest expense account 8830-2-0000-80-8543-2603, Intercompany Interest Expense-LU Co., for the 1st – 3rd quarters of the test-year 2022—with the remaining 4th quarter entries booked to SAP account 10430000. The offsetting entries were booked as credits to GP general ledger account 8830-2-0000-20-2170-2603, Intercompany Interest Payable – LU Co., which is mapped to SAP account 10234000.

The annual interest amount for the $17M in promissory notes—which totaled $776,694—was verified to the FERC Form 1. The filed schedule 1604.01(a)(24) reported the 2022 annual intercompany interest of $711,969 and Audit noted the variance of $64,725 between the filed amount and the FERC Form 1. The Company explained that the variance *"[...] is due to the timing of when the interest payments are typically paid, which is in January and July. This results in a one-month variance between the accrual in the payable account compared to the expense account."* The reported intercompany interest payment for each note was verified to supporting information provided by the Company and Audit confirmed the calculation for the monthly intercompany interest on each of the notes.

Other Long-Term Debt #224 $(15,000,000)

Filed schedule RR-5.1 reported that, as of 12/31/2022, the Company had totaled $15,000,000 in unsecured long-term notes. The following depicts the details for each of the outstanding notes:

Date Issued	Maturity	Lender	Rate	Principal	Annual Interest
11/01/93	11/01/23	First Colony Life-1	7.37%	$ 5,000,000	$ 368,500
07/13/95	07/01/25	First Colony Life-2	7.94%	$ 5,000,000	$ 397,000
05/15/98	06/15/28	Paul Revere Life	7.30%	$ 5,000,000	$ 365,000
				$ **15,000,000**	$ 1,130,500

Audit verified the 12/31/2022 balance of $(15,000,000) to SAP general ledger account 10224000, Other Long Term Debt. Audit noted that the balance on the general ledger—mapped from GP account 8830-2-0000-20-2910-2240—has remained the same since the prior rate case for the test-year 2018. The interest paid on the long-term debt for the test-year 2022 totaled $1,130,500. Audit recalculated the annual interest rate for each note and confirmed that the $1,130,500 was booked to SAP account 10427000, Interest on Long-Term Debt, with the offsetting entry booked to SAP account 10237000, Interest Accrued Long-Term Debt. Refer to the *Interest on Long-Term Debt* section of the report for further details on the monthly interest expense.

Obligations Under Capital Leases – Non-Current #227 $0

The FERC Form 1 and filed schedule 1604.01 reported no balance for the Obligations Under Capital Leases – Non- Current. The account had previously represented the long-term portion of the lease agreement for printers located in the Londonderry, NH facility; however, Audit noted that there was no account listed on the 2022 GL for the long term lease liability and the Company confirmed that the lease had ended. Audit reviewed the 2021 general ledger for GP account 8830-2-0000-20-2960-2271, Lease Liability Long Term and verified that the final quarterly lease payment was made in March, in the amount of $583, and cleared the January beginning balance on the account. The offsetting entry was confirmed to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Consequently, there was no balance left on the account for 2021 and 2022. Audit also reviewed the 2019 and 2020 general ledgers for the long term lease liability and noted quarterly journal entries recorded lease payments for the printers in Londonderry. The short-term portion of the lease obligation posted to GP account 8830-2-0000-20-2750-2431, Lease Liability Short Term. Audit confirmed that the combined accounts were offset to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Refer to the *Obligations Under Capital Leased – Current* for details regarding the current obligation for the leased printers.

Current and Accrued Liabilities

Accounts Payable $(4,513,650)

The filing schedule RR-4 line 41 indicates the total accounts payable figure at $4,513,650. The total was verified to the FERC From 1 and the following SAP general ledger accounts:

20003510232000	AR-Unapplied Payments	$(1,453,915)
20301010232000	Interim Liability	$(3,059,737)
		$(4,513,652)

The review of the FERC 232 general ledger revealed that there was no activity in the account for January through September. Audi questioned why there was no activity and the Company noted that *"The converted balance for unapplied from January – September were loaded to regulatory account 242 instead of 232".* Audit notes that the AR-Unapplied Payments should be accounted for in FERC 242 and not FERC 232.

Documentation provided shows that the September balance that was erroneously loaded to account 242 was in the amount of $(854,868**). Audit Issue #1**

Two journal entries comprise the AR-Unapplied Payments balance of $(1,453,915). The Company noted that *"the first entry in the amount of $(609,186) represents the accrual for unapplied payments (credits on customer accounts, not yet applied to invoices) in December 2022. The second entry in the amount of $(844,729) represents the accrual for unapplied payments not yet processed on the customer accounts (cash received, but not yet applied) for December 2022."*

Accounts Payable to Associated Companies $(1,039,197,481.56)

The filed schedule 1604.01 reported the balance of $(1,039,197,481.56). The balance was verified to the SAP general ledger 10234000, as depicted by the following accounts:

Account	Description	Balance a/o 12/31/2022	
201010-10234000	Interco AP	$	(544,878,284.23)
201020-10234000	Interco AP - Legacy	$	(493,607,228.14)
211610-10234000	Interco Interst P-L	$	(711,969.19)
	Total A/P to Associated Companies	$	(1,039,197,481.56)

Audit understands that the GP general ledger—as used prior to October 2022—recorded the settlement of intercompany activity. This activity is represented by the following GP accounts, which are now settled to the appropriate SAP general ledger account 11102010146000, Intercompany Accounts Receivable and account 10234000, Intercompany Accounts Payable:

8830-2-0000-20-2810-2079 Due from Liberty Utilities Canada
8830-2-0000-20-2810-2596 Due to APUC
8830-2-0000-20-2810-2603 Due to LU Co.
8830-2-0000-20-2810-2606 Due to Liberty Energy New Hampshire
8830-2-0000-20-2810-2626 Due to Liberty Utilities America Co.
8830-2-0000-20-2810-2635 Due to COGSDALE
8830-2-0000-20-2810-2639 Due from Liberty Utilities (Central) Services Corp.

The Company confirmed that the aforementioned GP accounts are now the "Legacy" SAP general ledger accounts, as of October 2022. Audit reviewed the GP and SAP balances and confirmed that the GP account balances, as of 9/30/2022, rolled into the SAP balances for the Legacy accounts: 11102010146000, Intercompany Accounts Receivable and 20102010234000, Intercompany Accounts Payable.

The FERC Form 1 reported a balance of $(75,125,573) for the Accounts Payable to Associated Companies. The Company confirmed that the balance was the calculated net from the Accounts Receivable from Associated Companies balance and the Accounts Payable from Associated Companies balance. Refer to the *Accounts Receivable from Associated Companies* section of the report for details regarding the FERC Form 1 reporting and calculation.

Audit reviewed the general ledger for the Intercompany Accounts Payable and noted monthly entries for the allocation of professional fees, as well as for the money pool interest and payments to vendors. Supporting information for the APUC allocation percentage calculation that was applied to the types of indirect costs for the indirect billing was provided, along with the money pool interest calculation information. Audit confirmed that the Due to APUC entries for the allocated indirect costs flowed through the intercompany account and were offset to the Outside Services APUC HO Allocations account. The intercompany corresponding GP and SAP account numbers are referenced in the previous paragraphs of this section. Refer to the *Outside Services Employed* and *Algonquin Power & Utilities Corp (APUC)* sections for details regarding the allocation methodology of APUC indirect costs.

Audit recalculated a sample entry for the monthly money pool interest and verified that the Due to LU entries flowed through the intercompany account 201020-10234000, Due to LU and were offset to account 450400-10430000, Interest on Debt to Associated Companies. Refer to the *Affiliate Service Agreements* and *Interest on Debt to Associated Companies* sections for further details regarding the money pool agreement.

An invoice from Asplundh Tree was verified to the general ledger for vegetation work in the maintenance of overhead lines. Audit confirmed that the sampled vendor payments flowed through the Due to Liberty Energy New Hampshire account, with the offset to Maintenance of Overhead Lines-Trouble. Audit understands that prior to October 2022, vendor payments flowed through the appropriate "Due to" account—such as Due to Liberty New Hampshire—as they were processed by the service Company. Refer to the *Maintenance of Overhead Lines* section of the report for further details regarding vegetation management jobs. Refer to the *Cost Allocation Manual (CAM)* section of the report for details regarding the allocation of shared costs.

Customer Deposits $(1,333,411.59)

The filing schedule RR-4 , line 11 total for Customer Deposits was verified to the general ledger accounts below. The total also agrees with the FERC Form 1.

Cor	Company Code2	G/L Account	GL	G/L Account2	Regulatory	GL - REG	DEC Balance	
3071	LU Granite State Electric	OCOA/246400	246400	Curr Cst Dpst Hld	2350	24640010235000	$	(1,238,402.89)
3071	LU Granite State Electric	OCOA/290400	290400	LT Cst Dpst Hld-Ctrl	2350	29040010235000	$	(1,057,963.22)
3071	LU Granite State Electric	OCOA/290410	290410	LT Cst Dpst Hld-Leg	2350	29041010235000	$	962,954.52
							$	(1,333,411.59)

Audit noted that the balances relating to Customer Deposits, account 235, have been as follows, since the prior test year of 2018, docketed as DE 19-064 $(1,278,349):

2019 $(1,249,583) a decrease of 2% over the prior rate case test year balance
2020 $(1,175,621) a decrease of 6% over the 2019 year-end balance
2021 $(1,206,777) an increase of 3% over the 2020 year-end balance
2022 $(1,333,412) an increase of 10% over the 2021 year-end balance.

Within RR-4 is a proformed debit of $101,109, adjusting the proposed test year balance to $(1,232,303). The adjusted figure would represent an increase over the 2021 year-end balance of 2%. Audit requested:

1. the process Liberty follows in determining if a deposit is required,
2.what caused the fluctuation in the balances,
3. on what basis the proforma was calculated.

In reply, 1. The Company restated Puc 1203.03 regarding the circumstances under which a customer may be required to provide a deposit. The internal procedure was not communicated.

2. The fluctuation in the balance from 2021 to 2022 was reportedly due to the price of energy being significantly higher. 3.The proforma was reported to have been based on the test year 13-month average of customer deposits.

Activity within the GP account 8830-2-0000-20-2113-2350 Customer Deposits account included 4,242 journal entries, with a 9/30/2022 balance of $(1,238,402.89). That figure, as noted in the grid above, was rolled into the SAP account, and no further activity was noted.

Interest Accrued from Customer Deposits posted in the Great Plains ledger to account 8830-2-000020-2116-2370. The September 30, 2022 balance was zero. Activity in the account showed 1,067 journal entries of primarily less than $5. One entry in the amount of $259.59, on 9/27/2022, was identified and clarification of it was requested. Liberty noted that the figure represented monthly interest posting for 241 customers' deposits. The Company noted a miscoding between Granite State Electric and EnergyNorth, which was identified and corrected during the test year. Liberty also noted that they "*discovered a coding error for 57 of the 3,219 GSE accounts with security deposits, which has prevented these customers from receiving their interest. The Company will make the correction and post the missing interest to the customers' accounts. The total amount of security deposits held for these 57 accounts as of December 2022 is $10,530. The estimated deposit interest owed based on the 5.5% rate in effect for that period is $145*." **Audit Issue #10**

Deferred Assets-Pension/OPEB #228

$(7,293,207) per the filing 1604.01(a)(1)(a) BS was verified to the FERC Form 1 and to general ledger accounts:

Great Plains		SAP		Total	
8830-2-0000-20-2930-2283	OPEB/FAS 106 Benefit Reserve	28012010228300	PBO Opeb Pen/FAS106	$	(5,577,094)
8830-2-0000-20-2930-2285	Long Term Pension Obligation	28003010228300	LT Pension Ob	$	(1,716,113)
				$	(7,293,207)

Audit reviewed, in the *Payroll* section of this report the quarterly pension contributions booked to FERC account 228 without exception.

Additional entries in the accounts include accruals, payments to Benestar, Excellus retirement billings and other. No exceptions were noted.

Interest Accrued #237 $(325,292)

The 12/31/2022 balance for the accrued interest was reported as $(325,292) on the filed schedule 1604.01(a)(1)(a) BS, as well as the FERC Form 1. The amount was confirmed to the SAP general ledger account 211010-10237000, Accrued Interest. The corresponding GP account 8830-2-0000-20-2116-2371 was comprised of 21 journal entries that totaled $(425,416.57), as of 9/30/2022; Audit confirmed that the September 2022 GP account balance rolled into the SAP year-end account balance.

Since the prior rate case for the test-year 2018, the interest accrued balance was reported at $(142,792) for each year, excluding the years 2020 and 2022, when the year-end balance was $(325,292). The supporting documentation was reviewed and Audit confirmed that the reported increase of $(182,500) from the previous year-end balance of $(142,792)—for the years 2020 and

2022—was due to the semi-annual interest for the Paul Revere note that was typically recorded in December, being recorded in January of the following year. The 2021 general ledger was reviewed and Audit confirmed that the 2020 Paul Revere semi-annual interest payment of $182,500 was recorded the following month, on 1/22/2021.

Audit reviewed supporting detail and verified credit entries on the account, in the amount of $63,791.66 and $30,416.67, for the monthly interest accrual on the long term notes from First Colony and Paul Revere, respectively. The offsetting debits were confirmed to GP account 8830-2-0000-80-8546-4270, Fixed Rate Interest Cost, and the equivalent SAP account 56030010427000, Interest Expense-Fixed Rate. Audit verified the journal entry for the reversing debits, recorded semi-annually on 6/16/2022, for the First Colony and Paul Revere notes and on 10/31/2022 for First Colony, with Paul Revere to be recorded in January 2023. Refer to the *Interest on Long-Term Debt* section of the report for details regarding the verification of the interest expense.

Obligations Under Capital Leases–Current #243 $(101,750)

Filed schedule 1604.01(a)(1)(b) BS and the FERC Form 1 each reported the Obligations Under Capital Leases-Current with a balance of $(101,750). The following represents the general ledger account balances, as of 12/31/2022:

210300-10243000	Miscellaneous Accrued Liab	$ (101,750)
246610-10243000	Current Operating Lease Obligation	$ -
	Total Obligations Under Capital Leases-Current	$ (101,750)

The short-term lease obligations were originally charged to GP accounts 8830-2-0000-20-2141-2431, Battery Storage Offset, and 8830-2-0000-20-2750-2431, Lease Liability Short Term. Audit confirmed that the September 2022 balances for both GP accounts rolled into the SAP year-end total of $(101,750).

The prior rate case for the test-year 2018 reported a balance of $0 for the total Obligations Under Capital Leases-Current. Audit noted that the 12/31/2022 credit balance of $(101,750) related to the Battery Storage Pilot Program, which was approved on January 17, 2019 in docket DE 17-189, Order No. 26,209. Specifically, the Order approved "*the costs of the program to participating customers [...as] either an upfront payment of $4,866, or payments of $50 each month for 10 years.*" As of 9/30/2022, Audit confirmed that there were 16 credit entries of approximately $6,000 each on GP account 8830-2-0000-20-2141-2431, Battery Storage Offset and mapped to SAP account 210300-10243000. The entries were for the individual loan billing of customers participating in the Battery Storage Pilot Program and who chose the $50 per month payment option. The Company confirmed that as part of the program, *"[...]customers are charged either $50 per month for ten years, $6,000.00 in total, or they would have paid $4,866.00 upfront for utilization of the batteries in the pilot[...]In 2021 and 2022, the Company collected the upfront payments from customers who chose that option and created the 'loan' for those customers who chose to pay $50 per month over ten years. Those entries were completed periodically, depending on when the customer's final signed contract was received."* Audit verified that the offsetting debit entry was made to GP account 8830-2-0000-10-1160-1439, Other AR-Special Contracts Battery Storage. Audit reviewed the Cogsdale system information for a sample of one of the loans—including the principal amount of $6,000, the corresponding customer ID and loan ID, as well as the monthly customer payment of $50 with the total number of payments identified as 120.

The beginning balance of $(583.33) on account 246610-10243000 represented the current obligation for leased printers that are at the facility located in Londonderry, NH. The Company stated that the operating lease ended in March of 2022. The only transaction recorded on GP account 8830-2-0000-20-2750-2431, Lease Liability Short Term—corresponding SAP account 24661010243000, Current Operating Lease Obligation—cleared out the account for the final quarterly payment of $583.33, recorded on 3/31/2022. Audit confirmed the lease retirement of $583 was reported as offset to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Refer to the *Obligations Under Capital Leased–Non-Current* for details regarding the long-term portion of the obligation for the leased printers.

Interest Income $(281,962)

The filed schedule 1604.01(a)(1)(a) PL reflected an Interest Income balance of $(281,962). Interest Income is not included within the revenue requirement schedules, as it is a below the line account.

The amount was verified to the FERC Form 1 and the general ledger account balances, as of 12/31/2022:

Account	Description	Balance
47030010419000	Interest Income	$ (259,745.02)
47050010419000	Rental Income	$ (22,217.35)
	Total Interest Income	$ (281,962.37)

The Rental Income recorded on account 470500-10419000 was included in the total Interest Income balance of $(281,962.37). The Company explained that the Interest Income total "[…]*also includes income from two tower rental agreements which were recorded as interest income in error and should have been recorded as rental income.*" Audit confirmed the credit entries on SAP rental income account 470500-10419000, in the total amount of $(22,217.35), for the October – December 2022 monthly tower rentals on the AT&T and Sprint towers. Audit noted that the total $(22,217.35) in tower rental income was erroneously recorded to the interest income account. As a result, the Revenue Requirement schedule RR-2.3, account 10454000 is understated. **Audit Issue #11**

The interest income was originally charged to GP account 8830-2-0000-40-4420-4190, Interest Income. Audit confirmed that the September 2022 balance on the account settled into the SAP account 470300-10419000 year-end total of $(259,745.02). The following represents the FERC Form 1 balances for the Company's interest income, as reported since the prior rate case for the test-year 2018:

Account Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Interest and Dividend Income	$ (467,804)	$ (262,376)	$ (482,430)	$ (281,962)

The Company explained that *"Most of the interest income is manually calculated on regulatory deferral balances, using the monthly prime interest rate or the interest rate on customer deposits, and recorded to the general ledger."* As such, entries booked on the account included the interest on the deferral balance for the LRAM, stranded costs, and storm costs. Refer to the *Accrued Expenses* section of the report for further details.

Audit also noted credits on the account for the monthly interest on the two Blackrock mutual funds. The Company provided the supporting monthly BlackRock statements, as well as the monthly interest calculation, and clarified that Blackrock is an external investment account that earns interest. The interest is reinvested and recorded to account 470300-10419000, Interest Income and offset to account 188010-10134000, Restricted Cash. Audit verified the monthly journal entries on the general ledger Interest Income account and confirmed the interest calculation to the monthly ending balance for the two funds—as used in the interest calculation—to the bank statements. Refer to the *Cash* section of the report for further details regarding the BlackRock investment.

A 10/1/2022 debit entry of $1,105,060 posted on the Interest Income account and was described as "GSE Parking Lot Entry" for the 4th quarter. The Company clarified that the entry was for the transfer of Q1-Q4 Money Pool interest and provided the calculation, based on the daily interest (earned)/charged. Audit sampled the Q1 pool interest and confirmed the calculation to the general ledger, with the offset entry to 450400-10430000, IC Interest Rev. Refer to the *Interest on Debt to Associated Companies* section of the report for details regarding how the money pool interest is booked.

Interest Expense $(2,503,459)

The 2022 total Interest Expense of $(2,503,459) was reported on the filed schedule 1604.01(a)(1)(1) PL and verified to the FERC Form 1. The following general ledger accounts represent the total Interest Expense for the test-year 2022:

SAP Account	Description		Balance a/o 12/31/2022
10427000	Interest on Long-Term Debt	$	1,130,500
10428000	Amortization of Debt Discount and Expense		2,183
10237000	Interest on Debt to Associated Companies		(4,075,337)
10431000	Other Interest Expense		518,505
10432000	AFUDC-Borrowed Funds (see *Utility Plant* section)		(79,309)
	Total Interest Expense (rounded)	$	(2,503,458)

Interest on Long-Term Debt #427 $1,130,500

The 12/31/2022 balance for the interest on long-term debt was reported as $1,130,500 on the filed schedule 1604.01, as well as the FERC Form 1. Audit noted that the balance has remained the same since the prior rate case for the test-year 2018. As of 9/30/2022, the balance on GP account 8830-2-0000-80-8546-4270, Fixed Rate Interest Cost totaled $847,874.97. Audit verified that the September balance on the former GP account rolled into SAP account 560300-10427000, Interest on Long-Term Debt.

The Company provided copies of the statements from JPMorgan Chase Bank for the debt service, detailing the interest payments for the First Colony and Paul Revere issues, which totaled $15,000,000. The following represents details for the monthly interest calculation applied to the long-term debt:

Date Issued	Maturity	Lender	Rate	Principal	Annual Interest	Monthly Interest
11/01/93	11/01/23	First Colony Life-1	7.37%	$ 5,000,000	$ 368,500	$ 30,708.33
07/13/95	07/01/25	First Colony Life-2	7.94%	$ 5,000,000	$ 397,000	$ 33,083.33
						63,791.66
05/15/98	06/15/28	Paul Revere Life	7.30%	$ 5,000,000	$ 365,000	$ 30,416.67
		Total		**$ 15,000,000**	$ 1,130,500	$ 94,208.33

Audit confirmed the interest amounts on the Chase bank statements to monthly debits on the account. The interest expense was booked monthly in the aggregate amount of $63,791.66 for both of the First Colony issues and in the amount of $30,416.67 associated with the Paul Revere issue. The offsetting credit entries were confirmed to GP account 8830-2-0000-20-2116-2371, Interest Accrued-LTD and mapped to SAP account 211010-10237000. Audit verified the bi-annual payment accrual debit entries made on 6/1/2022 and 10/31/2022; no true-ups or adjustments were recorded. Refer to the *Other Long-Term Debt* section of the report for further details regarding the monthly interest expense accrual.

Amortization of Debt Discount and Expense #428 $2,183

The filed schedule 1604.01(a)(1)(a) PL reflected an Amortization of Debt Discount Expense that totaled $2,183 for the test-year 2022. The amount was verified to the FERC Form 1 and the SAP general ledger account 561040-10428000, Amortization of Debt Discount and Expense. The prior rate case balance of $2,619 had remained unchanged until 2022, where there was a decrease of $436 in the $2,183 balance reported. The test year 2022 total expense of $2,183 was confirmed to ten debit entries for the monthly amortization expense of $218.26 each, during the months of January through October. Offsetting credit entries were verified as booked to account 189140-10181000, Unamortized Debt Expense. Audit inquired as to why there were no monthly amortization entries for November and December. The Company explained that *"The November and December 2022 entries to record the monthly amortization expense of $218.26 were charged to SAP[...]regulatory account 10920000 in error, instead of 10428000. As a result, $436.52 was reported in the incorrect regulatory account."* Audit noted the November and December amortization expense entries on SAP account 561040-10920000, Amrt Fn Cst-Debt Discount, totaled $436.52 for the two months; thus, the decrease in the expense balance that was reported from 2021 to 2022.

As of 9/30/2022, the balance on GP account 8830-2-0000-80-8541-4280, Amortize Debt Discount and Expense, totaled $1,964.34 and consisted of nine debit entries for the monthly amortization of the debt expense. Audit verified that the September balance on the former GP account rolled into SAP account 561040-10428000.

Audit confirmed the debit transactions on the general ledger to the debt expense amortization information that was provided by the Company. The straight-line method used in the calculation of the amortization was based on the unamortized debt discount balance of $30,694.43 from the Granite State Electric Acquisition Date of July, 2012. Refer to the *Long-Term Debt* section of the report for details regarding the debt.

Interest on Debt to Associated Companies #430 $(4,075,337)

Filed schedule 1604.01(a)(1)(a) PL and the FERC Form 1 each reported a balance of $(4,075,337) for the Interest on Debt to Associated Companies. The following represents the net of four SAP general ledger account balances that comprise the total, as of 12/31/2022:

Account	Description	Balance
50500010440000	Other Operating Exp	$ (1,077,479.83)
45040010430000	IC Interest Rev	$ (3,775,696.14)
56051010430000	Int Exp-IC Leg	$ 713,018.79
56052010430000	Int Exp-IC	$ 64,819.89
	Total Interest on Debt to Associated Companies	$ (4,075,337.29)

Corresponding to the SAP accounts, the GP account 8830-2-0000-80-8543-2603 Intercompany Interest Expense LU Co. and GP account 8830-2-0400-40-4434-2603 Intercompany Interest Income had a 9/30/2022 balance of $583,379.01 and $(1,077,479.83) respectively. The two intercompany interest GP accounts are currently settled to the aforementioned SAP accounts 10430000, Interest on Debt to Associated Companies, as of 10/01/2022. Audit confirmed that the September 2022 GP ending balances were rolled into the SAP year-end account balance of $(4,075,337.29).

Entries on the accounts included interest for the money pool and intercompany debt. The Company described the booking of the money pool interest by stating that, "*Corporate Treasury calculates the Money Pool interest daily, applying the prevailing commercial paper issuance and LIBOR rates, and posts the journal entries on a monthly basis.*" Audit sampled entries on each of the accounts and confirmed that the monthly pool interest on account 450400-10430000 IC Interest Rev., was offset to account 201020-10234000, Interco AP Legacy. Audit noted that the only entry on account 505000-1044000, Other Operating Exp, was in the amount of $(1,077,479.83) for a 12/31/2022 credit—offset to account 450400-10430000, IC Interest Rev—as a reclass entry "to correct Reg Acct" for the August and September 2022 money pool interest. Refer to the *Affiliate Service Agreements* section of the report for details regarding the money pool.

Monthly entries on account 560510-10430000, Int Exp-IC Leg, were for the interest paid on the $17,000,000 in long-term debt. Offsetting entries were confirmed to account 211610-10234000, Interco Interest P-L. An additional $1,145 in interest—posted monthly as $95.40—was booked for the intercompany deferred financing. Audit confirmed the offsetting entries as credits to GP account 8830-2-0000-10-1936-1000, Deferred Financing-Intercompany, which mapped to SAP account 10181000. Refer to the *Advances from Associated Companies* for further details regarding the interest rate for each note of the long-term debt.

Other Interest Expense Account #431 $518,505

The 2022 Other Interest Expense was listed as $518,505 (rounded), per filed schedule 1604.01(a)(1)(1) PL. The FERC Form 1 reported a balance of $518,502 for the account; Audit noted the three dollar variance and deemed it immaterial. The filed amount of $518,505 was confirmed to the SAP general ledger balance on account 56300010431000, Other Interest Expense, as of 12/31/2022. The corresponding GP account 8830-2-0000-80-8550-4310 totaled

$297,319.75, as of 9/30/2022 and Audit confirmed that the September 2022 GP account balance rolled into the SAP year-end account balance.

Transactions on the account included the interest expense that is associated with customer deposits, fees for letter of credit, and the carrying costs calculated on the regulatory deferral balances—such as the storm fund, the RGGI refund, Energy Efficiency, and default energy service. Audit sampled monthly interest expense entries on the regulatory deferral balances and confirmed the offset for the interest to the appropriate current regulatory liabilities account. Refer to the respective program audits—reviewed annually—for further details regarding the interest expenses related to the storm fund, RGGI refund, default service, and energy efficiency program.

Allowance for Funds Used During Construction (AFUDC) $(79,309)

The 2022 AFUDC was listed as $(79,309) per the filed schedule 1604.01(a)(1)(1) PL, as well as the FERC Form 1. Audit verified the total reported to SAP general ledger account 56201010432000, AFUDC Borrowed. The corresponding GP account 8830-2-0000-80-8550-4320 was comprised of 45 journal entries that totaled $(54,633.12), as of 9/30/2022; Audit confirmed that the September 2022 GP account balance had been rolled into the SAP year-end account balance. The AFUDC Equity component was booked to GP general ledger account 8830-2-0000-40-4700-4191, Allowance for Other Funds Used During Construction and mapped to SAP account 47040010419100 AFUDC Equity $(130,600). The general ledger balance for the AFUDC equity was tied to the filed schedule 1604.01(a)(1)(b) PL, as well as to the FERC Form 1. The GP account balance totaled $(90,238.05) as of 9/30/2022 and Audit confirmed that the amount had been rolled into the SAP account balance for the year-end.

The filed schedule RR-5 reported the weighted cost at the annual rate of 4.73% for the Equity component and at the annual rate of 2.87% for the Borrowed component. Audit reviewed information provided by the Company, including the AFUDC calculation and confirmed the weighted cost for the test year 2022. Sampled journal entries for the borrowed and equity portions were tied to the AFUDC calculation. Audit verified that monthly credit transactions posted on each account and were offset to the CWIP 10107000. Refer to the *Plant* section of the report for details regarding the AFUDC detail per work order.

REVENUE $(141,545,195)

The filing schedule RR-2 reflects the test-year revenue as:

Residential Sales	$ (77,521,597)
Commercial and Industrial Sales	$ (61,123,082)
Public Street and Highway Lighting Sales	$ (1,168,888)
Sales for Resale	$ (169,677)
Other Sales	$ 1,018,212
Total Revenue to Ultimate Customers	$(138,965,031) rounded
Miscellaneous Service Revenue	$ (536,454)
Electricity Revenue Rate Increment	$ -0-
Rent from Electric Property	$ (361,375)
Other Electric Revenues	$ (1,682,335)
Decoupling Revenue	$ -0-
Total Other Revenue	$ (2,580,163)
TOTAL REVENUE	**$(141,545,195)**

Audit verified the filing reported test-year ended 12/31/2022 Operating Revenue figure of **$(141,928,329),** to the 2022 FERC Form 1 as follows:

FERC Account per FORM 1	**12/31/2021 FERC Form 1**	**12/31/2022 FERC Form 1**	**% change 2022 v 2021**	**12/31/2022 SAP Yr End**	**FERC vs SAP variance**
440	$ (55,533,670)	$ (77,521,597)	**40%**	$ (77,521,596.72)	$ (0.28)
442 small	$ (42,425,000)	$ (54,543,141)	**29%**	$ (54,543,141.33)	$ 0.33
442 lg / ind	$ (7,515,140)	$ (6,579,941)	**-12%**	$ (6,579,941.13)	$ 0.13
444	$ (1,098,244)	$ (1,168,888)	**6%**	$ (1,168,887.52)	$ (0.48)
subtotal	$ (106,572,054)	$ (139,813,567)	**31%**	$ (139,813,566.70)	$ (0)
447	$ (155,523)	$ (169,677)	**9%**	$ (169,677.17)	$ 0.17
449.1	$ 708,219	$ 1,018,212	**44%**	$ 1,018,212.45	$ (0.45)
451	$ (505,695)	$ (536,454)	**6%**	$ (536,453.64)	$ (0.36)
454	$ (341,515)	$ (361,375)	**6%**	$ (361,374.93)	$ (0.07)
456	$ (1,032,561)	$ 355,575	**-134%**	$ 355,574.56	$ 0.44
456.1	$ -	$ (2,421,044)	**#DIV/0!**	$ (2,421,043.73)	$ (0.27)
TOTAL REV	**$ (107,899,129)**	**$ (141,928,330)**	**32%**	**$ (141,928,329)**	**$ (1)**

Audit verified the ending September 2022 Great Plains account balances were rolled into the SAP system accounts (identified below). Those balances were then verified to the FERC Form 1, and to the Revenue Requirement schedules noted.

Great Plains account number, name, balance as of 9/30/2022			SAP verification of 9/30 rollforward		SAP 12/31/2022	FERC Form 1	Filing
8830-2-0000-40-4290-4401	Residential Sales - Fixed Portion	$ (5,038,577.00)	40001010440000	Elec Rev Fx Mtr Res	$ (6,867,775.36)		RR-2.2
8830-2-0000-40-4290-4402	Residential Sales - Variable Portion	$ (23,299,564.76)	40010010440000	Elec Rev Us Mtr Res	$ (29,611,814.51)		RR-2.2
8830-2-0000-40-4290-4403	Residential Sales - Energy Cost	$ (28,384,763.45)	40020010440000	Elec Rev Pt Mtr Res	$ (41,042,006.85)	$ (77,521,596.72)	RR-2.2
8830-2-0000-40-4290-4423	Commercial Sales - Fixed Portion	$ (1,958,442.46)	40002010442000	Elec Rev Fx Mtr ComL	$ (2,680,242.39)		RR-2.2
8830-2-0000-40-4290-4424	Commercial Sales - Variable Portion	$ (23,317,596.94)	40011010442000	Elec Rev Us Mtr Com	$ (30,729,089.74)		RR-2.2
8830-2-0000-40-4290-4425	Commercial Sales - Energy Cost	$ (15,027,548.45)	40021010442000	Elec Rev Pt Mtr Com	$ (21,133,809.20)	$ (54,543,141.33)	RR-2.2
8830-2-0000-40-4290-4426	Industrial Sales - Fixed Portion	$ (181,267.40)	40005010442000	Elec Rev Fx Mtr Ind	$ (191,266.31)		RR-2.2
8830-2-0000-40-4290-4427	Industrial Sales - Variable Portion	$ (4,978,427.18)	40012010442000	Elec Rev Us Mtr Ind	$ (5,390,375.49)		RR-2.2
8830-2-0000-40-4290-4428	Industrial Sales - Energy Cost	$ (920,212.09)	40022010442000	Elec Rev Pt Mtr Ind	$ (998,299.33)	$ (6,579,941.13)	RR-2.2
8830-2-0000-40-4290-4441	Public Street&Highway Lighting - Fixed	$ (643,254.65)	40006010444000	Elec Rev Fx Mtr Pub	$ (806,159.04)		RR-2.2
8830-2-0000-40-4290-4442	Public Street&Highway Lighting-Variable	$ (137,164.82)	40013010444000	Elec Rev Us Mtr Pub	$ (177,278.13)		RR-2.2
8830-2-0000-40-4290-4443	Public Street&Highway Lighting - Energy	$ (130,279.15)	40023010444000	Elec Rev Pt Mtr Pub	$ (185,450.35)	$ (1,168,887.52)	RR-2.2
8830-2-0000-40-4290-4473	Sale for Resale - Fixed Portion	$ (285.52)		Elec Rev for Resale			
8830-2-0000-40-4290-4474	Sale for Resale - Variable Portion	$ (71,895.35)	40032010447000	all 3 accounts rolled to			
8830-2-0000-40-4290-4475	Sale for Resale - Energy Cost	$ (97,496.30)		1 SAP $(169,677.17)	$ (169,677.00)	$ (169,677.00)	RR-2.2
8830-2-0000-40-4290-4491	Prov for rate refunds	$ 2,358,017.56	40033010449100	Elec Rev Other	$ 1,018,212.45	$ 1,018,212.45	RR-2.2
8830-2-0000-40-4210-4510	Misc Service Revenues	$ (189,977.64)	40033010451000	Elec Rev Other	$ (478,838.64)		RR-2.3
8830-2-0000-40-4210-4511	Misc Ser Rev-Open Access DSM	$ (288,841.00)		combined into SAP	$ (57,615.00)	$ (536,453.64)	RR-2.3
8830-2-0000-40-4210-4561	Other Electric Revenue - Decoupling	$ (1,760,924.00)	400300104561000	Elec Rev Dis Cap Ch	$ (2,420,829.00)		RR-2.3
8830-2-0000-40-4460-4951	Decoupling Revenue	$ -					
			40039010456100	Ener Rev Other Res	$ (214.73)	$ (2,421,043.73)	RR-2.3
			40033010407300	Elec Rev Other	$ (383,134.66)	**Audit Issue**	**RR-2.13**
8830-2-0000-40-4210-4563	Other Elec Rev-Open Access Rev-Dstrbtn	$ 348,364.96	40030010456000	Elec Rev Dis Cap Ch	$ 653,316.84		RR-2.3
			40033010456001	Elec Rev Other	$ (228,257.62)		
8830-2-0000-40-4210-4520	Electricity Rev - Rate Increment	$ 319,010.00	40033010456000	Elec Rev Other to SAP	$ 313,650.00		RR-2.3
8830-2-0000-40-4210-4560	Other Electric Revenue	$ (5,360.00)		$313,650.00		$ 355,574.56	
8830-2-0000-40-4210-4540	Rental Income	$ (285,213.40)	40033010454000	Elec Rev Other	$ (361,374.93)	$ (361,374.93)	RR-2.3
						$ (141,928,328.99)	

Based on a review of the FERC Form 1, and the general ledger accounts that support that figure, the revenue in the filing is understated by $(383,135). Audit noted account OCOA/400330 Electric Revenue-Other, 10407300 $(383,135) on the Depreciation and Amortization Revenue Requirement schedule RR-2.12, line 8. The Company did proform it out of the Depreciation and Amortization schedule, but did <u>not</u> proform it into RR-2, RR-2.2, or RR-2.3. **Audit Issue #12**

<u>Account 440</u> on the FERC Form 1, Residential Sales was verified to SAP year-end balances in:
40001010440000 $ (6,867,775.36) Fixed Portion
40010010440000 $(29,611,814.51) Variable Portion
40020010440000 <u>$(41,042,006.85)</u> Energy Cost
Residential $(77,521,596.72) represents a 40% increase in sales over the 2021 year-end balance.

<u>Account 442</u> on the FERC Form 1, Small Commercial Sales was verified to SAP year-end balances in:
40002010442000 $ (2,680,242.39) Fixed Portion
40011010442000 $(30,729,089.74) Variable Portion
40021010442000 <u>$(21,133,809.20)</u> Energy Cost
Small Commercial $(54,543,141.33) represents a 29% increase in sales over the 2021 year-end balance.

Account 442 on the FERC Form 1, Large Commercial and Industrial Sales was verified to SAP year-end balances in:

40012010442000	$ (5,390,375.49)	Fixed Portion
40005010442000	$ (191,266.31)	Variable Portion
40022010442000	$ (998,299.33)	Energy Cost
Small Commercial	$ (6,579,941.13)	represents a 12% decrease in sales over the 2021 year-end balance.

Account 444 on the FERC Form 1, Public Street and Highway Lighting Sales was verified to SAP year-end balances in:

40006010444000	$ (806,159.04)	Fixed Portion
40013010444000	$ (177,278.13)	Variable Portion
40023010444000	$ (185,450.35)	Energy Cost
Small Commercial	$ (1,168,887.52)	represents a 6% increase over the 2021 year-end balance.

Account 447 on the FERC Form 1, Sales for Resale $(169,677) was verified to one SAP account, 40032010447000, Elec Rev for Resale.

Account 449.1, Provision for Rate Refunds, $1,018,212.45 on the filing RR-2 as Other Sales, was verified to the SAP account 40033010449100.

Audit verified each of the reported Other Revenue amounts on the supporting schedule RR-2.3, and subsequently to the referenced regulatory SAP general ledger accounts included on that schedule.

Within the FERC Form 1 was the identification of Border Sales in the amount of 970 megawatt hours. The DoE, via data request 5-21, asked "… *Please provide a detailed explanation of the information contained in this schedule regarding energy sales "Massachusetts Electric – Border Sales including how sale costs for this energy are established.*" The Company responded "…*The energy sales identified as "Massachusetts Electric – Border Sales" represent borderline sales, or Sales for Resale, to certain residential and commercial customers of National Grid located in Massachusetts who receive electric service from Liberty due to their proximity to Liberty's service area. The customers are billed monthly in accordance with a FERC Electric Tariff based on the Retail Delivery Service tariffs that the Company would apply to the retail locations served under the tariff if those retail locations were within the Company's service territory.*"

Audit had requested clarification of how the Cogsdale and SAP billing systems differentiate the Border Sales customers, how many customers are included in the Border Sales, and what rate classes. The Company indicated that in Great Plains there are approximately 170 customers in rate 41-ERD05NG. The customers are included in D05 in SAP, reported as one Sales for Resale-Residential. There are 10 commercial accounts billed as rate G3, reported as on Sales for Resale-Commercial. FERC Form 1, page 311 indicates the total Massachusetts Electric border sales was $169,677. That figure agrees with the Electric Operating Revenues schedule account 447, Sales for Resale.

Other Revenues

The Miscellaneous Service Revenue $(536,454) per the FERC Form 1 and the filing schedule RR-2.3 was tied to two SAP line items:

40033010451000	$(478,838.64)	8830-2-0000-40-4210-4510 Misc Service Rev
40033010451002	$ (57,615.00)	not in mapping in Puc 1604 section of the filing
	$(536,453.64)	

Audit reviewed the Great Plains January through September activity, over 6,000 entries of primarily $20 service charges in account 8830-2-0000-40-4210-4510, Miscellaneous Service Revenues. For that period, revenue recorded summed to $(189,977.64). Audit also reviewed 8830-2-0000-40-4210-4511, Miscellaneous Service Revenue-Open Access DSM, which for the January through September period summed to $(288,841.00). That account represents the Energy Efficiency Incentive calculated. Combined, these two accounts sum to $(478,828.64).

Within the SAP 40033010451000, Misc Serv Revs-Sls of Electy-FERCE, are monthly entries from January through October, which agree with the sum of both accounts' Great Plains activity, $(478,818.64). One journal entry in October, in the amount of $(20.00) reflects the full revenue of $(478,838.64). Activity was then noted in October, November, and December in account 40033010451002, Energy Efficiency Incentive. Three equal entries of $(19,205) each summed to $(57,615). From January through September, estimates of the incentive were posted to Misc Ser Rev-Open Access DSM 8830-2-0000-40-4210-4511.

Rent $(361,374.93) per the FERC Form 1 was verified to SAP account 40033010454000. The figure was included within the Revenue Requirement filing schedule RR-2.3. The January through September Great Plains account was 8830-2-0000-40-4210-4540, Rental Income. Audit verified that the monthly entries from January through September 2022 were converted into SAP for those months. The October through December entries were also reviewed.

The rental income represents utility pole and/or cable attachments, total for the reported t27 specific rental agreements. Audit requested and was provided with each agreement, originally excluding the number and type of attachments. Subsequent agreements did reflect the actual attachment details. Refer to **Audit Issue #11** which discusses an error with posting $(22,217.35) of rental income from AT&T and Sprint to Interest Income SAP account 47050010419000.

Other Electric Revenues $(1,682,334.51) per the filing RR-2.3 was verified to five SAP accounts:

40030010456000 Elec Rev Dis Cap Chg	$ 653,316.84	RR-2.3
40033010456000 Elec Rev Other	$ 313,650.00	RR-2.3
40033010456001 Elect Rev Other SOE Rate Increment	$ (228,257.62)	RR-2.3
40030010456100 Revs fm Tnmsn of Elec of Others	$(2,420,829.00)	RR-2.3
40039010456100 Revs fm Tnmsn of Elec of Others	$ (214.73)	RR-2.3
	$(1,682,334.51)	

$653,316.84 was reviewed in both the Great Plains account 8830-2-0000-40-4210-4563, Other Elec Rev-Open Access Rev-Distribution and the SAP accounts noted above. The activity reclassified revenues out of account 456x, and into Great Plains 8830-2-0000-20-2141-2422, Current and Accrued REP/VMP Provision and 8830-2-0000-10-1168-1821, Current Regulatory Asset-Special Audit. Those -1821 entries related specifically to the Property Tax Adjustment Mechanism (PTAM).

Schedule RR-2, line 15, Decoupling Revenue shows zero for the test year relating to FERC account 495. As part of the RDAF audit conducted by the Department of Energy Enforcement division (DE 22-052), Audit noted that from July 2021 through March 2022, decoupling entries were booked to 8830-2-0000-10-1169-1828, Deferred Decoupling Asset, and offset to 8830-2-0000-40-4460-4951, Decoupling Revenue. Beginning in March 2022, the revenue account -4460-4951 was cleared to 8830-2-0000-40-4210-4561, and all subsequent monthly revenue entries posted to that account. Per Order 26,619 in docket DE 22-018, the revenue decoupling adjustment clause was to be included in the transmission charge annual rate filing for reconciliation. It appears that the account number change is the result of Liberty interpreting the Order in that way.

Audit specifically verified the $(2,420,829) revenue on line 9 of RR-2.3, Revs fm Tnmsn of Electy of Othrs-Sls of Electy represents the revenue side of monthly revenue decoupling entries calculated to account for the difference between "actual revenue per customer" vs. "target revenue per customer". The offsetting entry posts to balance sheet account 131100 CRA R8 Adj Mech 10**182**300. $(1,760,924) of the total represents the net decoupling revenue January through September 2022, which agreed with Great Plains as of 9/30/2023. The remaining $(659,905) revenue represents net decoupling revenue October through December 2022 per SAP.

$(214.73) was verified to SAP account 4003901045610 as well, with the journal entry type listed as "CS", which within SAP stands for FICA CIS Posting. The amount is the sum of four entries, posted 11/3/2022, 11/14/2022, 12/14/2022, and 12/15/2022. The entries and total overall are immaterial, and additional testing was not conducted.

Tariff Test

Docket DE 22-035, Liberty's request for a Third Step Adjustment, for rates effective August 1, 2022, was approved, based on capital investments made in 2021 (exclusive of growth related projects at Tuscan Village South, investment at Golden Rock Feeder 19L2, and LED Street Light Conversion); a rate decrease to reflect cessations of recovery of DE 19-064 rate case expenses and the recoupment of the difference between temporary and permanent rates in DE 19-064. See Order 26,661 issued July 29, 2022. A compliance filing of the revised tariff pages was submitted on 8/5/2022. A lengthy PUC and DoE review of ongoing tariff filings occurred throughout 2022 and 2023.

Order 26,780 issued March 1, 2023 in docket DE 22-035 approved a downward adjustment of $(575,083) in the Company's distribution revenue requirement, and Order 26,781 issued March 3, 2023 approved Liberty's proposed credit to distribution rates associated with investments placed in service in 2021 with said refund to be reflected as a credit to distribution rates from March 1, 2023 through July 31, 2023.

Order 26,836, also in docket DE 22-035, issued 5/31/2023 approved an increase to distribution rates resulting from an error uncovered by the Company and brought to the attention of the PUC. A technical statement from the Company was filed on 4/6/2023 demonstrating an incorrect method was used to reduce the revenue requirement relating to the cessation of collection of the rate case expense portion approved in Order 26,661. (See Exhibit 9 in DE 22-035.) As a result of the error, the revenues during the test year were understated by a revenue requirement amount of $1,294,385. The Order explicitly noted that the amount was to be recovered over the course of one year, terminating May 31, 2024, while acknowledging the current DE 23-039 rate case.

As a result of the various tariff filings, Audit requested and was provided with the tariffs in place during the test year.

1. Effective January 1, 2022, the Eighth Revised Page 126 and Ninth Revised Page 127 were authorized in docket DE 20-092 by Order 26,553 issued November 12, 2021.

2. The Summary of Rates, Ninth Revised Page 126 and Tenth Revised Page 127 were authorized in docket DE 21-087, Order 26,559 issued on December 27, 2021 effective February 1, 2022.

3. The Tenth Revised Page 126 and Eleventh Revised Page 127, effective March 1, 2022, were approved in docket DE 20-092 by Order 26,579 issued February 10, 2022.

4. The Eleventh Revised Page 126 and Twelfth Revised Page 127, effective May 1, 2022, were approved in dockets DE 22-018, DE 22-014, and DE 20-092 by Orders (respectively) 26,619 and 26,620 issued April 28, 2022 and Order 26,621 issued April 29, 2022.

5. The Twelfth Revised Page 126 and Thirteenth Revised Page 127 were approved by Order 26,643 in docket DE 22-024, issued June 20, 2022 with rates effective August 1, 2022.

6. The Thirteenth Revised Page 126 and Fourteenth Revised Page 127 were approved by Order 26,651 in docket DE 22-035, issued July 29, 2022 with rates effective August 1, 2022.

7. Lastly, changes to rates effective November 1, 2022 were noted on the Fifteenth Revised Page 127, the Second Revised Page 128 (Rate EV-L, Commercial Plug in Electric Vehicle Charging Station), and the Second Revised Page 133 (Rate EV-M, Commercial Plug in Electric Vehicle Charging Station). The revision to page 127 was approved by Order 26,376 in docket DE 19-064, issued June 30, 2020 and Order 26,604 in docket DE 20-170 issued April 7, 2022. The EV tariff pages were approved by Order 26,604.

However, the identification of the calculation error described above occurred after the test year. As a result, the tariff in place through 2022, while based on assumptions that were calculated incorrectly, were the approved rates in place. Audit randomly sampled a selection of year-end invoices, using the aged accounts receivable listing. The Residential rate class D was verified to the 13th revised page 126, for effect August 1, 2022. The rates for rate class D did not change thereafter. Rates for the G1-TOU customers were verified to the 14th revised page 127 and the 15th revised page 127. The M/LED-1/LED-2 rates were verified to the 15th revised page 127. Rates for the G2 customers were verified to the 13th revised page 126.

	D	G1 TOU Sep - Oct	G1 TOU Oct - Nov	G1 TOU Nov - Dec	M/LED-1/LED-2	G2-General Long Hour
Customer Charge	$ 14.74	$ 435.18	$ 435.18	$ 435.18	$ -	$ 72.52
Distribution Charge	$ 0.05857	n/a	n/a	n/a	0.04064	0.00234
Distribution Charge-Off peak	n/a	$ 0.00175	$ 0.00175	$ 0.00175	n/a	n/a
Distribution Charge-On peak	n/a	$ 0.00591	$ 0.00591	$ 0.00591	n/a	n/a
Stranded Cost Charge	$ (0.00051)	$ (0.00051)	$ (0.00051)	$ (0.00051)	$ (0.00052)	$ (0.00051)
System Benefits Charge	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792
Transmission Charge	$ 0.03635	$ 0.02492	$ 0.02492	$ 0.02492	$ 0.01928	$ 0.02529
Energy Service Charge	$ 0.22228	n/a	n/a	n/a	$ 0.22228	$ 0.19864
Energy Service Charge-Off peak	n/a	$ 0.15134	$ 0.15134	$ 0.19864	n/a	n/a
Energy Service Charge-Off peak	n/a	n/a	n/a	$ 0.34354	n/a	n/a
Energy Service Charge-On peak	n/a	n/a	n/a	$ 0.19864	n/a	n/a
Energy Service Charge-On peak	n/a	$ 0.15134	$ 0.19864	$ 0.34354	n/a	$ 0.34354
Demand Charge	n/a	$ 9.22000	$ 9.22000	$ 9.22000	n/a	$ 9.27000
Miscellaneous Charge or Credit	various	various	various	various	various	various
High Voltage Metering	n/a	1%	1%	1%	n/a	n/a
High Voltage Delivery Credit	n/a	calculated	calculated	calculated	n/a	n/a

Audit verified December billings for customers in rate classes above. One of the G1 customers received an invoice that covered the periods 9/20/2022 through 10/19/2022, 10/20/2022 through 11/17/2022, and 11/18/2022 through 12/16/2022. It is unclear why this customer was invoiced for three months, although the Department of Energy Consumer Services division was informed by Liberty that at conversion to SAP, a significant number of both electric and gas customers had not received invoices. A quantification of the impact was requested through multiple meetings with the Company as well as through data requests in this docket, but specific quantification of customers and related revenues cannot be determined.

Overall, the tariff test determined each invoice reflected the appropriate charges for: Customer Charge, Distribution Charge, Distribution Charge-Off peak, Distribution Charge-On peak, Stranded Cost Charge, System Benefits Charge, Transmission Charge, Energy Service Charge, Energy Service Charge-Off peak, Energy Service Charge-On peak, Demand Charge, High Voltage Metering, calculated High Voltage Delivery Credit, customer reconnection fee, and a credit figure resulting from a group net metering host.

Unapplied Payments

Audit requested specific clarification regarding all unapplied payments as of the end of the test year. Monthly journal entries posted to Great Plains account 8830-2-0000-20-2111-2420 through September 2022, summing to $(854,868.49). Audit verified that that activity was rolled into SAP account 20003510242000. At year-end, the summary general ledger reflected a total of $(21,728.60). Audit was unable to verify the reported year-end figure to the detailed SAP activity, which at year-end, reflected a total of $(814,327.46. Audit communicated with Liberty several times attempting to understand what seemed to be a disconnect between the summary ledger and the detail, however, was inconclusive. The Unapplied Payments account was one of forty two #242 Miscellaneous Current and Accrued Liability accounts, that sum to $(35,849,681.42). FERC Form 1 shows a total for account 242 as $(32,120,029), a difference of $3,729,652. See A**udit Issue #1**

The difference between the SAP general ledger and the FERC Form 1 for all of account **242** was clarified by the Company to be accounts mapped incorrectly:

80111210408000 OH Payroll Tax	$ 4,620.26	exclude from #408, add to 242
24672010593000 Curr REC Obl Non-reg	$3,675,811.00	exclude from #593, add to 242
80117010921000 OH A&G n-Labor	$ 12,444.13	exclude from #921, add to 242
80111410924000 OH Property Insurance	$ 5,337.34	exclude from #924, add to 242
80111810925000 OH Injuries and Damages	$ 8,263.31	exclude from #925, add to 242
80111010926000 OH Benefits	$ 17,353.50	exclude from #926, add to 242
80111310926000 OH Pension/OPEB	$ 5,823.05	exclude from #926, add to 242
	$3,729,652.59	**Audit Issue #1**

Also noted on RR-2.2 was a flowthrough of $1,018,212 for the Provision for Refunds account 449, which Audit verified to the general ledger 40033010449100.

Liberty provided the monthly general ledger and Cogsdale then SAP revenue reconciliations, which were reviewed by Audit.

During the audit work related to DE 19-064, Audit questioned the reflection on the FERC Form 1 of the Forfeited Discounts 450 as Miscellaneous Service Revenues and another figure as Forfeited Discounts. In response, the Company provided details of how the GL data for both accounts was calculated because the figures were within the same general ledger account. The reflection within the 2022 FERC Form 1 correctly reflected Miscellaneous Service Revenue on the line for account 450 only.

Accrued Utility/Unbilled Revenue

Audit reviewed the general ledger activity and noted that the monthly unbilled credits auto-reverse on the first of the following month.

Audit requested the unbilled revenue calculations for December 2021, January 2022, December 2022 and January 2023, to review for significant changes between December year-end calculations and January monthly calculations:

12/2021 Unbilled Revenue Recognition		Debit	Credit	01/2022	
88302-0000-10-1162	Accrued Utility Revenue	$ 2,248,595.81		$ 2,356,516.99	
8830-2-0000-40-429	Residential Sales-Fixed		$ (257,027.47)		$ (258,840.44)
8830-2-0000-40-429	Residential Sales-Variable		$ (914,155.55)		$ (1,032,591.29)
8830-2-0000-40-429	Commercial Sales-Fixed		$ (100,387.08)		$ (98,972.94)
8830-2-0000-40-429	Commercial Sales-Variable		$ (757,378.48)		$ (765,112.26)
8830-2-0000-40-429	Industrial Sales-Fixed		$ (9,717.63)		$ (9,341.75)
8830-2-0000-40-429	Industrial sales-Variable		$ (177,476.99)		$ (156,383.29)
8830-2-0000-40-429	Street Lighting Fixed		$ (32,452.61)		$ (35,275.03)
		$ 2,248,595.81	$ (2,248,595.81)	$ 2,356,516.99	$ (2,356,517.00)

12/2021 Unbilled Commodity Cost					
8830-2-0000-10-110	A/R Under Collected	$ 2,139,308.62		$ 2,424,919.50	
8830-2-0000-40-429	Provision for Rate Refunds		$ (2,139,308.62)		$ (2,424,919.50)
		$ 2,139,308.62	$ (2,139,308.62)	$ 2,424,919.50	$ (2,424,919.50)

12/2022 Unbilled Revenue Recognition		Debit	Credit	01/2023	
110100-10173000	Accrued Utility Revenue	$ 2,818,874.71		$ 2,729,645.00	
400010-10440000	Residential Sales-Fixed		$ (312,834.54)		$ (310,662.59)
400100-10440000	Residential Sales-Variable		$ (977,677.21)		$ (1,107,475.31)
400020-10442000	Commercial Sales-Fixed		$ (126,857.10)		$ (130,944.24)
400110-10442000	Commercial Sales-Variable		$ (1,277,916.44)		$ (1,072,981.84)
400050-10442000	Industrial Sales-Fixed		$ (3,513.17)		$ (3,511.17)
400120-10442000	Industrial sales-Variable		$ (74,034.12)		$ (66,679.17)
400060-10444000	Street Lighting Fixed		$ (38,244.70)		$ (31,193.57)
400130-10444000	Street Lighting-Variable		$ (7,797.43)		$ (6,197.11)
		$ 2,818,874.71	$ (2,818,874.71)	$ 2,729,645.00	$ (2,729,645.00)

12/2022 Unbilled Commodity Cost					
130800-10142000	A/R Under Collected	$ 4,586,344.00		$ 4,541,895.24	
400330-10449100	Provision for Rate Refunds		$ (4,586,344.00)		$ (4,541,894.24)
		$ 4,586,344.00	$ (4,586,344.00)	$ 4,541,895.24	$ (4,541,894.24)

Supporting calculations were provided for each month. However, the details relating to the Base Energy Service Rate portion were redacted within the 12/2021 and 1/2022 unbilled calculation details, and simply eliminated in the 12/2022 and 1/2023 calculations. Audit requested the complete unredacted versions of the calculation, and was provided with the confidential pages in the DE 21-087 Energy Service Reconciliation Schedule HMT/AMH-1 Rates Page 1 of 1 and HMT/AMH-2 Rates Page 1 of 1, and DE 22-024 Attachment HMT/AMH-1 Page 1 of 1 and Attachment HMT/AMH-2, Page 1 of 1, rather

<u>Payroll</u>

During test year 2022, all GSE employees were employed by Liberty Utilities Service Corp.

Payroll is completed on a weekly and bi-weekly basis. Union employees, such as linemen, are paid on a weekly basis whereas non-union employees are paid bi-weekly.

The final 2022 pay period for weekly paid employees ended December 24, 2022 and was paid December 30, 2022. The final pay period for bi-weekly paid employees ended December 17, 2022 and paid December 23, 2022. Audit reviewed both detailed payroll registers for the final pay periods.

Audit requested the payroll journal entry for Liberty NH, 3070, final weekly and bi-weekly pay period of the year. GSE provided the payroll journal entry signoff, for both weekly and bi-weekly, which shows information such as the account and amount.

Audit additionally requested the journal entry booking the payroll from 3070 to GSE 3071 and ENG 3072. Liberty noted "*this is no longer done as a manual journal entry hence there is no actual document, instead it is an automated process in SAP. The payroll team received a "Success Report" from SAP when the entry goes through"*. Liberty provided am example of the "Success Report" which states "Document Posted Successfully:" with a numerical and alphabetical code.

Audit requested an explanation as to how the payroll is reconciled to the general ledger now that a previously used report is no longer available in SAP. Liberty's response was as follows:

"The process used to reconcile payroll is first to run a Timesheet report to gather all labor hours entered for a particular month. Then the total amount of labor per weekly/bi-weekly timesheet is compared to the Payroll Register report dollar amounts. Minor variances are expected due to the timing of transactions posting in the Timesheet system (WFS) vs Payroll Processing System (SAP)."

Liberty provided the reconciliation for the payroll paid in the month of December 2022. The timesheet report shows a total of $1,096,705 for bi-weekly while the payroll register shows $1,086,078, resulting in a variance of $10,627. For weekly payroll, the timesheet report shows $2,178,999 and the payroll register shows $2,180,340, resulting in a variance of ($1,341.04). Audit notes that the reconciliation provided did not include any general ledger detail as requested. Audit is unable to determine if the general ledger accurately reflects the payroll expense for 2022. **Audit Issue #13**

<u>Payroll Test</u>

Audit requested and received a listing of all Liberty employees in which a portion of their full payroll expense is charged to GSE. Audit randomly selected and seven weekly employees and eight bi-weekly employees for a review of timesheets, paystubs and W2s.

Bi-weekly timesheets for the period of December 4, 2022 through December 17, 2022 were reviewed in detail. Audit was able to tie seven of the eight bi-weekly paid employees' timesheets to the payroll register detail and W2s. The final timesheet reviewed was a four factor allocation and was therefore not on the payroll register. Four factor allocation is further discussed on page 4 of the report. Types of pay included regular hours, vacation pay, and jury duty pay.

Audit noted that when rest time is noted on the actual timesheet, it is when banked rest hours are being used. If the rest hours are earned during the pay period, it will show in the result tab of the payroll system as it is entered by the supervisors not the actual employee. Audit verified the rest hours that were paid and earned during the pay period were done without exception.

Audit reviewed the seven weekly paid employees' timesheets for the period of December 18, 2022 through December 24, 2022 in detail. Six of the electric employee's hourly rate, based on job title, was verified to the Union Contract without exception. The seventh employee's pay rate was higher than the hourly rate noted for their job title in the union handbook. Further review of the employee's timesheet noted they were acting in the roll of "troubleshooter" and was therefore paid the troubleshooter hourly rate. No exception was noted.

The types of pay employees received during the final pay period included regular, overtime, call back, storm duty, mutual aid storm duty and others.

All hours recorded on eight weekly employees' timesheets were verified to the payroll register detail without exception. All premium rates, such as overtime, storm duty and mutual aid, paid to the employees were verified to the union contract without issue. The premium rate paid for storm duty versus mutual aid storm duty is at different rates. Audit questioned how the rates are differentiated on the timesheet and it was noted that the WBS element - job code will be different for storm duty and mutual aid storm duty.

Schedule RR-3.4 in the filing stated the total O&M payroll for 2022 was $5,038,152 as shown below:

FERC Account	2022 Test Year Salaries and Wages OCOA/500000	2022 Test Year Vacation & Other TO OCOA/500100
563	148	-
580	995,037	6,173
581	129,067	2,331
582	137,514	-
583	705,708	3,649
584	(272)	-
585	30,738	-
586	302,977	(12,832)
587	45,670	-
588	290,215	3,589
590	13,469	175
591	105,704	41
592	131,559	-
593	568,816	7,374
594	22,178	-
595	3,701	-
596	27,115	31
597	26,823	-
598	29,806	-
901	36,259	-
902	260,785	-
903	503,920	(399)
905	16,000	-
909	24,257	-
912	12,609	3,370
916	167,170	-
920	725,045	(135,238)
922	(283,886)	-
923	8,440	-
935	1,579	-
Total in Test Year	**5,038,152**	**(121,737)**
Total Salaries and Wages in Test Year	**4,916,416**	

GSE provided a trial balance for the payroll, which summed to $6,071,380. The trial balance provided showed the total labor per month per FERC account. Of the thirty FERC accounts noted in the Schedule RR-3.4, nine of them did not tie to the payroll trial balance provided by GSE.

Audit compared the trial balance totals to the detailed general ledgers. For the months of January through September, while GP was in use, the O&M payroll trial balance matched the detailed general ledger.

During this comparison of the trial balance to the GL, Audit determined that the payroll trial balance for October through December, in SAP, included other labor expenses and not just salaries and wages. Audit reviewed the detail SAP GL and calculated only the salaries and wages to tie to Schedule RR-3.4.

No exception was noted with the comparison of Schedule RR-3.4 and the 2022 detail general ledger.

Audit notes that filing Schedule RR-2.1 shows total O&M payroll as $5,682,718. This figure includes Salaries & Wages, Vacation & Other TO and overtime paid. The $4,916,416 test year total in Schedule RR-3.4 only includes Salaries & Wages and Vacation & Other TO.

The Dayforce Payroll Register Reports, weekly and bi-weekly combined, shows a total payroll of $36,182,458 for the year. The payroll register reflects all payroll for NH, which includes GSE and ENG. Due to this, Audit was not able to directly tie the Schedule RR-3.4 to the Dayforce report. GSE previously noted during the rate case audit in Docket DE16-383 that the Dayforce report will not tie directly to Schedule RR-3.4 as Dayforce is only NH employees where Schedule RR-3.4 represents all payroll charged to NH.

GSE's payroll is processed through Ceridian. Audit reviewed the Ceridian contract in detail, which noted the contract terms and fees charged.

Union contracts and Payroll Policies and Procedures that were in place during the test year were obtained and reviewed.

Liberty Utilities and Algonquin Payroll

Audit requested and received the November 2022 direct and indirect LUC, LUSC, and LABS billings. Audit reviewed the detail in the billings for payroll and payroll taxes. Please refer to the *Allocation* section of this report for a detailed review.

Temporary Employees

Audit requested the total paid to temp agencies and to which general ledger the expenses were booked. In response, GSE provided documentation that totaled $456,528.50 paid to Balance Professionals. The response also noted the *"expenses were charged to GL account 500300"*, which is noted to be Outside Services.

Audit reviewed the Excel document sent in response to the request and attempted to verify it to the detail general ledger. Audit began with the GP detail for January through September which showed a total of $404,502 in expenses for Balance Professional. The response provided showed the vendor name, document date, document number, and document amounts. Additional information was also provided but no general ledger account was included. Audit attempted to verify the response to the GL based on the document date, document number and/or amount as noted in the response. Audit notes that the GP GL shows a total of $111,032.77 being expensed to GSE for Balance Professionals to the following accounts:

8830-2-0000-10-1618-1070	$ 81,815.40
8830-2-0000-10-1655-1084	$ 320.32
8830-2-9800-69-5200-9230	$ 436.80
8830-2-9815-69-5200-9230	$ 56.03
8830-2-9820-69-5130-9210	$ 8,419.32
8830-2-9820-69-5200-9230	$ 6,639.36
8830-2-9825-51-5435-5880	$ 733.92
8830-2-9825-69-5130-9210	$ 8,151.66
8830-2-9825-69-5200-9230	$ 4,133.98
8830-2-9851-51-5430-5870	$ 219.64
8830-2-9851-51-5435-5800	$ 106.34
	$ 111,032.77

Audit then attempted to verify the SAP October through December audit response to the detail general ledger. The audit request shows a total of $52,027 being booked to the general ledger for Balance Professional during the last three months of the year. The detail GL shows $30,393 as being booked to SAP account 50030010920000 in 2022.

Audit was unable to verify any of the information provided to the detail GP and SAP general ledger. **Audit Issue #14**

End of Year Accruals

Audit received the payroll accruals booked for weekly and bi-weekly payroll for the days worked in December 2022 but not paid until January 2023. As the final pay in 2022 for bi-weekly employees was for the period ending 12/17/22, the payroll accrual was for the period of 12/18/22 through 12/31/22. The final pay period for weekly employees ended 12/24/23, therefore accruals were for the period of 12/25/23 through 12/31/23.

Audit requested supporting documentation for the end of year payroll and vacation accruals. The documentation provided, shows it is for company code 3070, Liberty NH. Audit requested supporting documentation for the accrual calculations and only received the journal entries booking the accrual. Due to not receiving the payroll support, Audit was unable to verify the payroll accruals to the GSE general ledger. **Audit Issue #15**

Employee Benefits

Audit requested a listing of all payments made for employee benefits such as health, dental, retirement and others for the month of December. GSE provided a listing of all group benefits journal entries. Because all employees are employed by Liberty Utilities Service Group, the full amount of the benefits is expensed to company 8810/3070. A 30/70 allocation is done and 30% of the charges are allocated to 8830/3071.

Audit reviewed the Liberty Utilities, 3070, general ledger employee benefits entries from December 2022. Audit recalculated 30% of each entry and tied the amount to the following GSE general ledger account entries:

FERC Account	SAP GL Code	Natural Account	NAME	Amount
926	0L_3071_10167_1016725100_500170_10926000	500170	Group Benefits	119,079.55
408	0L_3071_10167_1016725100_500120_10408000	500120	Federal Unemployment taxes/Tx Oth Inc Tx-St Unempl Tax	142.51
926	0L_3071_10167_1016725100_500160_10926000	500160	401k Plan Expenses/Pension Plan Expenses/401K Match	99,897.10
926	0L_3071_10167_1016725100_500170_10926000	500170	Group Benefits	(159,261.80)

No exception was noted with the allocation of the employee benefits to GSE's general ledger. There was an exception with the account the Federal Unemployment taxes were booked to as noted in the *Payroll Taxes* section.

Per the IBEW union contract, pages 39 and 40, employees who do not meet a certain criteria (age plus years of service) were to be moved from the Liberty Energy Utilities Corp Retirement Plan for Union Employees to the Liberty Utilities Cash Balance Pension Plan. This was effective January 1, 2016. Employees who are under the age of 55 as of December 31, 2015 and were moved to the new pension plan were to have the Company make annual deposits to their 401K plan at the end of each calendar year for a total of 10 years. For employees who were over 55 and converted, the Company is to make annual deposits until the employee reached the age of 65.

Per the USW (United Steel Workers) union contract, pages 48 and 49, employees who do not meet that same criteria are also being moved from the Retirement Plan to the Pension Plan effective January 1, 2017. Annual deposits for the USW employees were to begin at the end of 2017.

Audit requested, from the Company, the total paid in transition deposits for 2022. Liberty noted that $38,183 was booked for IBEW and $194,891.10 was booked for USW to SAP account 500160. Audit reviewed the SAP GL detail for account 50016010926000 and was unable to verify the payment amounts.

Additional information was provided to Audit noting that the previously provided transition total of $233,074.10 was the NH total and not GSE. Support showed the $233,074.10 amount being allocated 70/30 with $99,987.10 being booked to GSE. Audit recalculated the amount without exception.

Audit verified the amount booked to the GSE (3071) GL to the following accounts on 12/31/2022:

Debit 50016010<u>926</u>000	$99,987.10	
Credit 11101010<u>146</u>000		$99,987.10

<u>Retirement Plan</u>

Audit requested a listing of payments that were made in 2022 to fund the retirement plan. GSE provided a summary of pension contributions, which shows by quarter, contribution amount for Pension Plan and Defined Benefit Pension Plan. The summary shows the GSE Pension contribution for Quarter One being $197,750 and the Quarter Two – Quarter Four contributions were $200,670 each. The total Pension contributions for the year were $799,760.

The summary of Defined Benefit Pension Plan contributions shows quarterly amounts for GSE as $100,000 for the first quarter and $99,000 for the second through fourth quarters totaling $397,000.

Audit reviewed in detail the general ledger account 8830-2-0000-20-2930-2285, Long Term Pension Obligations. Audit was able to verify the Quarter One, Quarter Two and Quarter Three, Pension Plan and Defined Pension Plan, contributions to the GP GL without exception. Audit verified the Fourth Quarter contribution booked to SAP account 28003010228300 without exception.

The quarterly contribution amounts were booked to the general ledger, for both the Pension Plan and Defined Benefit Pension Plan on the following dates; 4/12/2022; 7/12/2022; 7/14/2022 and 12/16/2022. On 10/31/2022 the amounts of $200,670 and $99,000 were credited to the account. The journal entry did not note the reason for the credit.

<u>Incentive Plan</u>

In the filing requirements, beginning on Bates page I-139, are the details of all officer and executive incentive plans. Additional incentive plan information was provided in response to DOE Data Request 4-25. Included in this information was the costs of each incentive program for 2022.

A total of $600,09.85 was expensed in 2022 for short term incentive bonuses. The data request response noted it was booked to FERC account 920. Audit verified the total for the year to SAP general ledger account 50022010920000 without exception.

A total of $48,550.53 was booked to FERC account 920 for the long term incentive plan. Audit was able to verify that amount to the detail SAP GL account 50021010920000 without exception.

The data request response also noted that $20,423.82 was booked to FERC 926 for employee stock purchase plan (ESPP). The response also notes that *"in preparing this response, the Company identified that $5,472.44 ($18,241.46 * 30%) of the ESPP was not allocated from LUNH (Company 3070) to Granite State Electric (Company 3071) in the test year. The Company will correct that amount in its next cost of service update in this proceeding."*

Audit was able to verify the $20,423.82 for ESPP to the general ledger detail without exception.

Severance Pay

Liberty provided a response to Department of Energy Data Request 4-38 noting $118,806.65 was paid for severance during 2022. The response to DOE 4-38 also noted that $36,424.81 was paid in 2021 and $15,775.91 paid in 2020 for severance. The amount of severance paid in 2022 was 226% higher than 2021 and 653 % higher than 2020.

Audit requested documentation showing the GL accounts to which the $118,806.65 in severance was booked. In GSE's response to the audit provided the following breakdown of the severance paid:

Pay Date	Year	GL Account	Amount
10/28/2022	2022	3070-500000-1016625300	$ 4,657.46
11/10/2022	2022	3070-500000-1016625300	$ 4,657.46
11/25/2022	2022	3070-500000-1016625300	$ 4,657.46
12/9/2022	2022	3070-500000-1016625300	$ 4,657.46
12/23/2022	2022	3070-500000-1016625300	$ 4,657.46
1/9/2023	2022	3070-500000-1016625300	$ 4,657.46
			$ 27,944.76
5/13/2022	2022	3060-500000-1014910100	**$ 83,278.84**
12/23/2022	2022	3070-500000-1016648100	**$ 7,583.04**
Total			**$ 118,806.64**

Audit was unable to verify the amounts to the GL detail as the severance is paid through payroll and not as a separate line item.

The bi-weekly payroll register for 2022 shows a total of $7,583.04 being paid through the NH payroll. The weekly payroll register does not show any severance being paid in 2022 to NH employees.

Payroll Taxes

The payroll taxes, as stated on Filing Schedule RR-2.11, were verified to the general ledger and FERC Form 1, account 408.

Great Plains Accounts		SAP Accounts		Year End Balance
8830-2-9810-69-5040-4080	Social Security Taxes	50011010408000	SS/CPP/Emp Pension	$ 457,572.75
8830-2-9810-69-5041-4080	Federal Unemployment Taxes	50012010408000	Unemp/Emp Insurance	$ 4,266.97
8830-2-9810-69-5041-4082	State Umemployment Taxes	50012010408200	Unemp/Emp Insurance	$ 26,441.45
8830-2-9810-69-5042-4080	Medicare	50015010408000	Medicare/Healthcare	$ 125,785.88
		50013010408000	FICA Taxes	$ 236.79
		85311210408000	As Prl Tx-Intrc	$ 28,631.62
				$ 642,935.46

Audit reviewed the payroll tax general ledger detail in both GP and SAP. Audit notes that there was no activity in the SAP Social Security Tax, Federal Unemployment Tax, State Unemployment Tax, and Medicare general ledger accounts in October, November or December 2022. Audit was unable to verify any of the payroll tax general ledger accounts to supporting documentation received during the audit process.

Audit requested clarification was to what the new SAP account 85311210408000 with an ending balance of $28,631.62 was used for. GSE responded with the following:

"As Prl Tx-Intrc, account 853112-10408000, records the settlement of the assess payroll tax component of overhead costs associated with <u>*intercompany*</u> (underlined for emphasis) *labor costs recorded to 10408000. There were no costs recorded prior to October due to following a different overhead process in GP in which overhead costs were recorded in total, not by component, and charged directly to the respective GL account."*

The SAP general ledger included a FERC 408 account that was not included on filing Schedule RR-2.11. This was account number 80111210408000, OH Payroll Tax, totaling $4,620.26. Audit also requested additional information on the use of this account and received the following from GSE:

"OH Payroll Tax, account 801112-10408000, records the settlement of the payroll tax component of overhead costs associated with labor costs recorded to 10408000. There were no costs recorded prior to October due to following a different overhead process in GP in which overhead costs were recorded in total, not by component, and charged directly to the respective GL account."

For the months of January through September, for each pay period the payroll taxes and benefits are booked to 8810 and cleared at the end of the month. The monthly 8810 tax amounts were then allocated to 8830 and 8840 using the 70/30 split. Following the conversion to SAP, the taxes and benefits are booked to Company 3070 and allocated to 3071 and 3072 using the 70/30 split.

Following the conversion to SAP, no tax entries were booked for the months of October, November and December to the 408 accounts. Audit requested a copy of the payroll tax clearing journal entry for December 31, 2022. There was only one amount, $142.51, for payroll taxes. Audit recalculated the payroll tax amount to be 30% of the amount booked to 3070 without exception. The journal entry shows the unemployment taxes were booked to FERC account 920.
Audit Issue #16

Audit requested a payroll tax account reconciliation for the year of 2022. GSE provided an Excel spreadsheet showing the total State Unemployment, Federal Unemployment, Social Security and Medicare taxes. The Excel spreadsheet detailed the tax amount per pay period for both weekly and bi-weekly pay. GSE noted in their response to the request that the tax detail provided was for all LUSC employees and not specific to NH. Due to this, Audit was unable to tie the payroll tax amounts from the reconciliation back to the NH year end payroll registers.

Audit was able to tie the detail for all LUSC employees to their tax filing Form 940, Employer's Annual Federal Unemployment (FUTA) Tax Return, and to the New Hampshire Unemployment Summary of Deposits and Filings. Audit was unable to verify the Form 941, Employer's Quarterly Federal Tax Return to the payroll tax reconciliation provided of Social Security and Medicare expenses.

Operations and Maintenance Expenses $111,435,705

Great Plains general ledger software Account string information, reflects:

Company GSE	US Dollar	Site/Dept	Class	Natural Account	Sub-account
8830-	2-	XXXX-	XX-	XXXX-	XXXX

The first three digits of the final sub-account represent the FERC Uniform System of Accounts account number. Effective October 1, 2022, the Company converted from Great Plains to the SAP software system. The account string information relating to that new system (generally) is:

3071 is Granite State Electric
XXXXXX 6 Digit number is the corporate general ledger account number
XXXX 4 digit code is the regulatory identification number
XXXXXXXXXXXXX is a combination of the 6 digit corporate general ledger account number and the four digit regulatory identification, with 3 place holders for subaccounts.

The reported Operations and Maintenance expense total on the filing schedule RR 2.1 was $110,587,557. The FERC Form 1 was $111,435,705 and the 12/31/2022 SAP was $110,727,635 indicating the following variances:

Filing Schedule 2.1	FERC Form 1	SAP General Ledger as of 12/31/2022	VARIANCES Schedule 2.1 vs. FERC Form 1	VARIANCES FERC Form 1 vs. SAP GL as of 12/31/22
$ 110,587,557.00	$111,435,705.00	$ 110,727,635.00	**$848,148.00**	**$ 708,070.00**

The variances are addressed throughout this report in various Audit issues. For the test year, overall operations and maintenance expenses **increased by 49%** over the 2021 ending balances.

Below is the roll-forward of the Operations and Maintenance Expense accounts per the FERC Form 1, since the prior 2018 test year: Refer to **Audit Issue #1**

		12/31/2019	12/31/2020	12/31/2021	12/31/2022	% change 22 vs. 21
555	Purchased Power	$ 40,022,127	$ 32,977,041	$ 32,423,121	$ 72,139,166	122%
	Total Power Production Expense	$ 40,022,127	$ 32,977,041	$ 32,423,121	$ 72,139,166	122%
561.4	Scheduling, System Control and Dispatch Services	$ 533,940	$ 561,142	$ 617,507	$ 427,346	-31%
563	Overhead Line Expenses	$ 1,316	$ 3,012	$ 2,388	$ 4,498	88%
565	Transmission of Electricity by Others	$ 21,586,953	$ 24,841,129	$ 26,260,820	$ 19,502,455	-26%
570	Maintenance of Station Equipment	$ -	$ -	$ -	$ -	#DIV/0!
	Total Transmission Expenses	$ 22,122,209	$ 25,405,283	$ 26,880,715	$ 19,934,299	-26%
580	Operation Supervision and Engineering	$ 1,342,483	$ 1,427,462	$ 1,503,612	$ 1,224,031	-19%
581	Load Dispatching	$ 280,622	$ 247,677	$ 180,680	$ 126,630	-30%
582	Station Expenses	$ 141,228	$ 181,075	$ 264,595	$ 152,948	-42%
583	Overhead Line Expenses	$ 744,316	$ 588,943	$ 894,444	$ 1,170,626	31%
584	Underground Line Expenses	$ 56,320	$ 1,255	$ 3,397	$ 14,326	322%
585	Street Lighting and Signal System Expenses	$ 14,761	$ 28,326	$ 26,248	$ 39,132	49%
586	Meter Expenses	$ (73,724)	$ 7,337	$ 193,471	$ 315,949	63%
587	Customer Installation Expenses	$ 70,898	$ 58,172	$ 54,261	$ 48,988	-10%
588	Miscellaneous Expenses	$ 1,309,496	$ 1,063,451	$ 1,233,172	$ 1,613,700	31%
	Total Distribution Operation Expenses	$ 3,886,400	$ 3,603,698	$ 4,353,880	$ 4,706,330	8%
590	Maintenance Supervision and Engineering	$ 19,071	$ 16,490	$ 14,742	$ 13,943	-5%
591	Maintenance of Structures	$ 128,959	$ 107,071	$ 137,304	$ 129,865	-5%
592	Maintenance of Station Equipment	$ 117,218	$ 217,753	$ 298,547	$ 238,334	-20%
593	Maintenance of Overhead Lines	$ 3,023,162	$ 2,948,878	$ 4,619,392	$ 5,452,702	18%
594	Maintenance of Underground Lines	$ 44,932	$ 26,023	$ 21,887	$ 167,310	664%
595	Maintenance of Line Transformers	$ 16,596	$ 54,153	$ 38,087	$ 3,701	-90%
596	Maintenance of Street Lighting and Signal Systems	$ 100,966	$ 67,293	$ 42,695	$ 39,278	-8%
597	Maintenance of Meters	$ 62,838	$ 58,366	$ 45,165	$ 53,762	19%
598	Maintenance of Miscellaneous Distribution Plant	$ 59,960	$ 84,450	$ 47,590	$ 59,472	25%
	Total Distribution Maintenance Expenses	$ 3,573,702	$ 3,580,477	$ 5,265,409	$ 6,158,367	17%
	Total Distribution Expenses	$ 7,460,102	$ 7,184,175	$ 9,619,289	$ 10,864,697	13%
901	Supervision	$ 105,818	$ 59,119	$ 48,490	$ 45,592	-6%
902	Meter Reading Expenses	$ 356,325	$ 326,375	$ 345,953	$ 353,272	2%
903	Customer Records and Collection Expenses	$ 1,322,332	$ 1,067,091	$ 1,129,379	$ 1,049,339	-7%
904	Uncollectible Accounts	$ 152,841	$ 233,314	$ 281,647	$ 272,932	-3%
905	Miscellaneous Customer Accounts Expenses	$ 29,592	$ 36,479	$ 29,720	$ 20,000	-33%
	Total Customer Accounts Expenses	$ 1,966,908	$ 1,722,378	$ 1,835,189	$ 1,741,135	-5%
907	Supervision	$ -	$ -	$ -	$ -	#DIV/0!
909	Informational and Instructional Expenses	$ 50,723	$ 100,090	$ 72,065	$ 97,960	36%
910	Misc. Customer Service and Informational Expenses	$ 6,956	$ -	$ 1,482	$ -	-100%
	Total Customer Service and Informational Expenses	$ 57,679	$ 100,090	$ 73,547	$ 97,960	33%
912	Demonstrating and Selling Expenses	$ 10	$ -	$ 150	$ (10,827)	-7318%
913	Advertising Expense	$ 206	$ -	$ 252	$ -	-100%
916	Miscellaneous Sales Expenses	$ 171,261	$ 192,485	$ 208,419	$ 170,411	-18%
	Total Sales Expenses	$ 171,477	$ 192,485	$ 208,821	$ 159,584	-24%
920	Administrative and General Salaries	$ 2,759,425	$ 2,906,055	$ 2,883,082	$ 2,877,428	0%
921	Office Supplies and Expenses	$ 922,168	$ 1,226,518	$ 1,425,717	$ 2,287,231	60%
922	Administrative Expenses Transferred-Credit	$ (10,430,407)	$ (10,563,333)	$ (11,574,397)	$ (8,002,460)	-31%
923	Outside Services Employes	$ 3,374,761	$ 3,410,426	$ 3,048,900	$ 2,381,415	-22%
924	Property Insurance	$ 1,550,463	$ 1,500,862	$ 1,572,228	$ 1,589,317	1%
925	Injuries and Damages	$ 554,459	$ 589,428	$ 800,546	$ 927,599	16%
926	Employee Pensions and Benefits	$ 4,239,168	$ 4,251,696	$ 4,713,113	$ 3,697,502	-22%
928	Regulatory Commission Expenses	$ 521,240	$ 519,161	$ 547,366	$ 643,455	18%
930.2	Miscellaneous General Expenses	$ 2,639	$ 220,171	$ 61,330	$ (115,412)	-288%
931	Rents	$ 154,099	$ 168,379	$ 192,391	$ 205,469	7%
	Total Administrative and General Operation Expenses	$ 3,648,015	$ 4,229,363	$ 3,670,276	$ 6,491,544	77%
935	Maintenance of General Plant	$ -	$ -	$ -	$ 7,320	#DIV/0!
	Total Administrative and General Maintenance Expenses	$ -	$ -	$ -	$ 7,320	#DIV/0!
	Total Administrative and General Expenses	$ 3,648,015	$ 4,229,363	$ 3,670,276	$ 6,498,864	77%
	TOTAL Operation and Maintenance Expenses	**$ 75,448,517**	**$ 71,810,815**	**$ 74,710,958**	**$111,435,705**	49%

FERC Form 1 reflects the following relating to Power Production and Transmission expenses:

555 Purchased Power	$72,139,166
561.4 Scheduling, System Control and Dispatch Services	$ 427,346
563 Overhead Line Expenses	$ 4,498
565 Transmission of Electricity by Others	$19,502,455
	$92,073,465

Audit notes that all 4 accounts were proformed out per revenue requirement schedule RR-2.1. Audit verified the reported **flow-through expense accounts on the filing RR-2-1** to the 2022 detailed general ledger. Specifically:

Purchased Power – Account 555 $72,139,166

Audit verified that the Great Plains activity from January 2022 through September 2022 was incorporated into the SAP year-end balances:

8830-2-0000-52-5455-5551 Purchased Power-Variable	$ -0-
8830-2-0000-52-5455-5552 Purchased Power-Fixed & SO	$44,453,339.60
8830-2-0000-52-5455-5553 PP-NEP-Access Charge-Elim	$ (452,573.97)
Great Plains as of 9/30/2022	$44,000,765.63

The FERC Form 1 balance of $72,139,166 was verified to the SAP general ledger year-end balance. The Great Plains activity was rolled into the following SAP accounts:

52001010555000	Elec Pur Power Misc	$ 61,368,862.82
52001010555001	Elec Pur Power Misc	$ 10,860,546.00
52001010555002	Elec Pur Power Misc	$ (90,243.14)
		$ 72,139,165.68

The overall power production expenses increased by 122% over the 2021 ending balances. Entries among the 3 accounts included CTC, Stranded Cost Revenue, monthly purchase power accruals, and ISO remittances. Because the accounts above were identified as flow through items, Audit reviewed the account activity, but did not perform further test work. The accounts and balances were verified to the filing schedule RR-2.4.

Transmission Expenses – Accounts 561.4, 563 and 565

The FERC Form 1 balance of $427,346 balance for account 561.4, Scheduling, System Control and Dispatch Services was verified to both the GP account, formerly account 8830-2-0000-51-5440-5614 and SAP account 52001010561400. The net GP activity was rolled into SAP through September 30, 2022 with no other transactions past this date. Overall expenses decreased 31% from 2021 and included 9 entries for ISO-NE invoices that were all posted mid-month. Audit did not perform further test work since the account is a flow though account and was proformed out on schedule RR-2.1 and RR-2.5.

Account 563, Overhead Line Expenses in 2021 consisted of 3 GP accounts which were the following:

8830-2-0000-51-5010-5630	Overhead Lines-Labor
8830-2-0000-51-5410-5630	Overhead Lines
8830-2-9851-51-5010-5630	Overhead Lines

The GP accounts were combined into one account in 2022 in account 8830-2-9851-51-5010-5630 which had an ending balance of $148.05 as of September 30, 2022. The GP account was rolled forward into the following 4 SAP accounts with the ending balance of $4,498 verified to FERC Form 1 and to filing schedules RR-2.1 and RR-2.5

50000010563000	Salaries and Wages	$ 148.05
50030010563000	Outside Svs	$ 2,474.86
50500010563000	Other Operating Exp	$ -0-
80000010563000	Lbr Alloc	$ 1,875.20
		$ 4,498.11

The overall expense were 88% more than the 2021 and consisted of 1 payroll entry totaling $148.05 for services from 1/9/2022 to 1/15/2022 and was offset to account 8830-2-0000-20-2810-2606, Due to Liberty Energy New Hampshire. The other entries in SAP were minimal debit and credit reversals summing to $4,350.06.

The FERC Form 1 Account 565, Transmission by Others amount of $19,502,455 was verified to the SAP general ledger account 52001010565000. Audit confirmed the GP activity from January through September 2022 former GP account 8830-2-0000-51-5441-5650, was rolled for to the one SAP account. The SAP ending balance amount was consistent with the filing amount listed on schedule RR-2-1. The 2022 expenses were 26% less than 2021. Expenses consisted of monthly payments to ISO New England, Inc (ISO). and New England Power, Co. (NEP). Both the ISO and NEP charges are for local and regional transmission service. Audit reviewed the activity however no further test work was completed, as previously mentioned, the account was proformed out on schedule RR-2.1 and RR-2.5.

Account #580, Operation Supervision and Engineering $1,224,031was verified from the following 22 SAP accounts, included in the filing schedule RR-2.6 to the FERC Form 1:

50000010580000	Salaries and Wages	$	995,037.23
50001010580000	Overtime	$	1,716.61
50005010580000	AllocCorp Lbr Leg	$	(97,201.36)
50010010580000	Vacation & Other TO	$	6,173.16
50121010580000	Fleet-Fuel	$	(13,458.82)
50500010580000	Other Operating Exp	$	250,933.86
50501010580000	Current Exchng Fees	$	5.33
50530010580000	Clr CIAC CWIP P&L	$	-0-
80000010580000	Lbr Alloc	$	5,954.64
80300010580000	Assess Lbr	$	(28,690.43)
80302010580000	Assess Material	$	155.00
80304010580000	Assess Other	$	819.10
80305010580000	Assess Fleet - Asses	$	15.32
80308010580000	Assess Meals	$	2,411.56
80308510580000	Assess Travel	$	2,860.81
80311010580000	Assess OH Benefit	$	97.46
85300010580000	Assess Lbr-Intrc	$	90,044.96
85304010580000	Assess Other-Intrc	$	1,720.70
85305010580000	As Fleet - Intrc	$	161.57
85308010580000	Assess Meals -Intrc	$	4,616.01
85308510580000	Assess Travel-Intrc	$	2,650.70
85311010580000	As OH BenIntrc	$	(1,992.58)
		$	1,224,030.83

Audit verified the Great Plains 9/30/2022 balances in eight individual accounts to the SAP 9/30/2022 starting balance. The overall expense total for 2022 represents a 19% decrease from the 2021 expense total.

The January through September 2022 GP entries in Account, 8830-2-9854-51-5435-5800 -Operation – Engineering included monthly fleet allocation with 1 reversal and 1 recalculated fleet charge occurring in February, there was also 1 reclassification entry in April 2022. The January through September 2022 net activity in the former GP account 9854-51-5435-5800 was rolled into SAP account 50500010580000. Audit could not trace any transactions past September in this account or any other 580 account related to the monthly fleet allocations. **Audit Issue #17**

Audit also reviewed a large credit entry/job dated 9/12/22 and totaled ($16,830). The entry was offset to GP account 8830-2-0000-10-1020-1310 (Cash) and was payment from Kearsarge Solar, LLC related to an impact study. The Company clarified it was a "*customer payment for a solar project application*"

Account #581, Load Dispatching. The FERC Form 1 amount of $126,630 was verified to the following GP Accounts January through September 2022:

8830-2-9851-51-5010-5810	Load Dispatching	$ 1,189.24
8830-2-9851-51-5400-5810	Load Dispatching	$ 99,359.13
8830-2-9853-51-5010-5810	Load Dispatching	$ 8,014.13
		$108,562.50

The 3 GP amounts were rolled into the following 10 SAP accounts:

50000010581000	Salaries and Wages	$ 129,066.73
50001010581000	Overtime	$ (592.31)
50005010581000	AllocCorp Lbr Leg	$ 1,149.05
50010010581000	Vacation & Other TO	$ 2,331.11
50500010581000	Other Operating Exp	$ (8,201.83)
50510010581000	Cost Alloc to Cap	$ (9,891.41)
70200010581000	BS Lbr Offset	$ 5,113.65
80300010581000	Assess Lbr	$ 8,597.41
80311010581000	Assess OH Benefit	$ 206.97
85300010581000	Assess Lbr-Intrc	$ (1,149.05)
		$ 126,630.32

Audit verified that the starting September balance in SAP agrees with the GP ending September balance.

The total overall SAP amount of $126,630 agrees with FERC Form 1 and filing schedule RR-2.1 and RR-2.6. This account reflected a 30% decrease from calendar year 2021.

All the net activity from January 2022 to September 2022 in the former GP accounts 9851-51-5010-581 and 9853-51-5010-5810 were rolled into SAP account 50000010581000. The 2 former GP accounts reflected 9 weeks of payroll and 3 bonus accruals and 2 accrual reversals from 1/1/22 to 9/30/22. Audit notes that the net activity former GP account 9851-51-5400-5810 was also rolled into SAP account 50000010581000 and included amortization of prepaid expenses and 1 P-Card expense totaling $45.34.

The SAP account 50000010581000 reflected maintenance costs, an interest charge with an interest corrective entry, and 2 charges for Schneider Electric totaling $7,164.89 and $3,615.95. The Company advised the transactions were amortization expenses both noted to be amortized from "1/2022 – 12/2022". The Company further clarified they were "monthly amortization of maintenance agreement". SAP account 80300010581000 (Assess Lbr) had 1 November payroll entry for an unknown specified time period and in December there were 3 payroll entries and payroll reversals for unknown time periods. There were also 7 allocation burden entries, each entry totaling $5,113.65 with an accompanying reversal entry. Audit reviewed 2 credit entries entitled "GSE Missed A&G Assessment Correction 12.2022". The Company advised the credits were part of settlement agreement and was part of a larger year end journal entry. The Company noted that "*these entries do not relate to any settlement agreements or dockets approving missed assessments…The use of the term "settlement" by the Company in this context relates to the settlements process within SAP. That is consistent with the description of the process contained in the "Customer Information System and General Ledger" section of the audit report. In SAP, "settlement" is the process in which costs accumulated on one cost object is moved or "settled" to its settlement cost object. The most common example is WBS settlements. A WBS is configured with a settlement rule that determines where the costs initially incurred on the WBS settles after the settlement process is run. For an OpEx WBS, the settlement rule is usually the cost center where those costs would be budgeted. For a CapEx WBS, the settlement rule is the CWIP balance sheet GL account.*

Assessment is the process in which costs accumulated on one cost object (usually a cost center) are allocated to multiple cost objects (usually capital WBSs) based on the pre-configured rules. It's a process to spread indirect overhead charges to specific projects. The key components of an assessment cycle include: the sending cost object (usually a cost center), the receiving cost objects (usually capital WBS's) and a base (usually labor or total projects) that is used to determine what percentage of OH costs each receiving cost object would be allocated. An example of this is the A&G assessments process which allocates a portion of indirect labor costs associated with back office A&G employees to capital projects."

Account #582, Station Expenses $152,948 per FERC Form 1. The filing schedule RR-2.6 reflected the same accounts and total:

50000010582000	Salaries and Wages	$ 137,514.41
50030010582000	Outside Svs	$ 1,986.48
50500010582000	Other Operating Exp	$ 815.82
80000010582000	Lbr Alloc	$ 12,631.19
		$ 152,947.90

Audit notes that the former GP account 8830-2-9851-51-5010-5820 included all payroll transactions and reconciliation entries while GP account 8830-2-9851-51-5405-5820 included monthly fleet spread charges and payments to outside vendors. As with many GP accounts the net activity was initially rolled into 1 SAP account 50000010582000 with corrective entries made in December 2022.

In GP 8830-2-9851-51-5405-5820 Audit reviewed the activity and noted the following:

4 invoices for Chippers	$ 16,105.00
2 invoices for Asplundh Tree Expert Co.	$ 3,045.15
6 invoices for Avedisian Landscape & Irrigation	$ 3,575.00
6 invoices for Joe Gauci Landscaping LLLC	$ 4,615.00
3 invoices for JP Pest Services	$ 817.00
3 invoices for Kevin Dube - Dube Property Maintenance	$ 2,250.00
3 invoices Landmark Property Maintenance	$ 2,165.00
1 invoice for United Power Group, Inc.	$ 900.00
P-Card Expenses	$ 177.43
Fleet Spread	$ 631.14
Net accruals and reversals	$ 0.03
TOTAL EXPENSES THROUGH 9/30/22	**$ 34,280.75**

Overall, account 582 reflects a 42% decrease in expenses for year-end 2022 compared to year-end 2021.

Account #583, Overhead Line Expenses $ 1,170,626 per the FERC Form 1 and the filing schedule RR-2.6 was verified to the following SAP accounts:

50000010583000	Salaries and Wages	$	705,708.23
50001010583000	Overtime	$	5,964.61
50005010583000	AllocCorp Lbr Leg	$	(14,727.09)
50010010583000	Vacation & Other TO	$	3,648.98
50030010583000	Outside Svs	$	135,551.62
50500010583000	Other Operating Exp	$	137,355.32
50530010583000	Clr CIAC CWIP P&L	$	-0-
80000010583000	Lbr Alloc	$	189,247.00
80300010583000	Assess Lbr	$	(6,849.70)
85300010583000	Assess Lbr-Intrc	$	14,727.09
		$	1,170,626.06

Total Account #583 agrees with the filing schedule RR-2.1 and RR-2.6. Overall, account 583 reflects a 31% increase in expenses for year-end 2022 compared to year-end 2021.

Audit requested supporting documentation for the following four clearing entries in Account 583, which was provided by the Company on 9/16/23. All offset entries were made to Stores Expense Undistributed #8830-2-0000-10-1380-1630 and CWIP 8830-2-0000-10-1618-1070:

1. Clearing Entry: 8830 Clear GL#1380-1630 SEP22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ 304,886.97	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ -	$ (194,365.44)
8830-2-0000-10-1618-	Construction Work In Progress	$ -	$ (64,788.48)
8830-2-9851-51-5410-	Overhead Line Expenses	$ -	$ (45,733.05)
		$ 304,886.97	$ (304,886.97)

2. Clearing Entry: 8830 CLear GL#1380-1630 AUG22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (114,620.83)
8830-2-0000-10-1618-	Construction Work In Progress	$ 73,070.78	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 24,356.93	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 17,193.12	$ -
		$ 114,620.83	$ (114,620.83)

3. Clearing Entry: 8830 CLear GL# 1380-1630 MAR22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (69,906.28)
8830-2-0000-10-1618-	Construction Work In Progress	$ 44,565.25	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 14,855.09	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 10,485.94	$ -
		$ 69,906.28	$ (69,906.28)

4. Clearing Entry: 8830 Clear GL# 1380-1630 FEB22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (67,793.29)
8830-2-0000-10-1618-	Construction Work In Progress	$ 43,218.22	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 14,406.08	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 10,168.99	$ -
		$ 67,793.29	$ (67,793.29)

Audit also reviewed the following 9 invoices:

	VENDOR	DATE	AMOUNT
1	Richard Paradie	9/20/2022	$ 12,134.72
2	Town Of Salem NH/Orig. Doc. #15866	9/21/2022	$ 11,411.50
3	Stella-Jones Corporation/Orig. Doc. #Rct00061596	6/29/2022	$ 11,297.00
4	Stella-Jones Corporation/Orig. Doc. #Rct00061427	6/14/2022	$ 11,839.24
5	JCR Construction Co. Inc.	6/7/2022	$ 11,648.06
6	Stuart C. Irby Co./Orig. Doc. #Rct00061055	5/16/2022	$ 21,138.90
7	Northeast Public Power Association/Orig. Doc. #70660	3/31/2022	$ 10,095.00
8	Arthur J. Hurley Co., Inc./Orig. Doc. #Rct00060522	3/29/2022	$ 10,470.00
9	Itron Inc/Orig. Doc. #609119	2/25/2022	$ 17,353.92

Invoices consisted of employee reimbursement for conference attendance, Town charges for police details, utility poles, construction charges for foreman and linemen, material charges such as clamps and arm bolts, Apprentice Line Work Program charges for 3 employees, 750 foot reels, and single contact connectors.

Account #584 Underground Lines $14,326 per Schedules RR-2 was verified to the following SAP general ledger accounts and to the total shown on line 138, page 320-323 of the FERC Form

50000010584000	Salaries and Wages	$ (271.66)
50001010584000	Overtime	$ 378.42
50030010584000	Outside Svs	$ 13,763.66
50500010584000	Other Operating Exp	$ -0-
80000010584000	Lbr Alloc	$ 455.46
		$ 14,325.88

Audit tested the largest invoice totaling $10,912.50 in the SAP GL. The invoice was provided on 9/23/23 and was from USIC Locating Services, LLC. Charges were a flat fee for location services, after hours charges, additional footage charges, and 272 "footage site visits". 2 GP GL accounts reflected 3 weeks of payroll for 6/26/22 – 7/9/22 along with 1 payroll accrual entry and one job/work order entry.

Total Account #584 reflects a <u>322% increase in expenses</u> for year-end 2022 compared to year-end 2021.

Account #585 Street Lighting and Signal Expenses $39,132 per the FERC Form 1 and the filing schedules RR-2 and RR-2.6 was verified to the following accounts:

GP account as of 9/30/22:

8830-2-9851-51-5010-5850	Street Lighting & Signal Systems	$32,066.53

SAP accounts through 12/31/22:

50000010585000	Salaries and Wages	$ 30,738.43
50500010585000	Other Operating Exp	$ -
80000010585000	Lbr Alloc	$ 8,393.32
		$ 39,131.75

Account 585 had a total overall <u>increase of 49%</u> in 2022 expenses compared to 2021. Audit reviewed the account activity and noted weekly payroll, bonus accruals, and 2 reclassification entries. No further testing was performed.

Account #586 Meter Expenses $ 315,949 per the FERC Form 1 and the filing schedules RR-2 and RR-2.6 was verified to the following GP accounts through 9/30/22:

8830-2-9851-51-5010-5860	Meter Expenses	$ 180,873.97	Labor
8830-2-9851-51-5425-5860	Meter Expenses	$ 60,641.38	Expenses
		$ 241,515.35	

The GP activity through 9/30/2022 was rolled into the following SAP accounts, with year-end balances of::

50000010586000	Salaries and Wages	$ 302,977.30
50001010586000	Overtime	$ 84,758.44
50005010586000	AllocCorp Lbr Leg	$ (124,878.77)
50010010586000	Vacation & Other TO	$ (12,832.41)
50050010586000	Equip & Machin Rents	$ 1,034.13
50330010586000	Misc Other Deduction	$ 2,214.01
50500010586000	Other Operating Exp	$ -
80000010586000	Lbr Alloc	$ 22,156.38
80300010586000	Assess Lbr	$ (96,504.81)
80302010586000	Assess Material	$ 2,315.04
80304010586000	Assess Other	$ 363.22
80305010586000	Assess Fleet - Asses	$ 118.32
80308010586000	Assess Meals	$ 3,987.09
80308510586000	Assess Travel	$ 4,846.25
80311010586000	Assess OH Benefit	$ 516.09
85300010586000	Assess Lbr-Intrc	$ 145,344.55
85308010586000	Assess Meals -Intrc	$ 636.96
85308510586000	Assess Travel-Intrc	$ 5,773.62
85311010586000	As OH BenIntrc	$ (26,876.36)
		$ 315,949.05

Account 586 overall had a 63% increase in expenses in 2022 over calendar year 2021.

Expenses consisted of weekly payroll entries, reimbursements to employees, payments for p-card purchases, payments to vendors, fleet spreads, reclassifications, and accruals and reversals. Audit requested the detailed journal entry information regarding the following 4 general ledger transactions in the SAP GL 50500010586000 that were all dated 12/31/22. 3 entries part of the same year-end journal entry (Entry #100085265):

1. Journal Entry #100086917

Account Number	Account Description	Debit Amount	Credit Amount
50500010920000	Maint. of Station Equip - Other Operating Exp.	$ 622,881.48	
UNKNOWN	**UNKNOWN**	**$ 626,192.38**	
50500010586000	Meter Expenses - Other Operating Exp		$ (1,249,073.86)
		$ 1,249,073.86	$ (1,249,073.86)

2. Journal Entry #100085265

Account Number	Account Description	Debit Amount	Credit Amount
50500010586000	Meter Expenses - Other Operating Exp	$ 646,148.89	
50500010586000	Meter Expenses - Other Operating Exp	$ 385,721.64	
50500010586000	Meter Expenses - Other Operating Exp	$ 195,852.29	
50500010999999	Default - Other Operating Exp	$ 1,069,835.09	
UNKNOWN	**UNKNOWN**		**$ (2,297,557.91)**
		$ 2,297,557.91	$ (2,297,557.91)

The Company originally did not provide detailed information, just highlighted transactions to where the partial amounts were offset. In journal entry #10085265 the Company responded that all 3 debit transactions in account 586 were offset to account 999 or a “Default” account, however the transaction they provided was another debit entry and an offsetting credit entry could not be identified. Liberty subsequently provided the complete journal entry #100086917 which included 39 specific line items and the complete journal entry #100085265, which included 170 specific line items. Audit verified that the journal entries include some combination of offsetting accounts. However, due to the number of line items of each of the entries, the specific offsets to these portions of the entries listed as UNKNOWN could not be determined. Audit does confirm that the entries include the $622,881.48 and $(1,249,073.86) individually, as well as the four debits listed for journal entry #100085265.

Journal Entry #100086917 included:

66 debit entries to numerous accounts summing to	$5,315,910.38	
104 credit entries to numerous accounts summing to		$(5,315,910.38)

Journal Entry #100085265 included:

32 debit entries to numerous accounts summing to	$3,052,076.63	
7 credit entries to numerous accounts summing to		$(3,052,076.63)

Audit also reviewed the following 2 vendor invoices from the GP GL that showed charges for transformers and terminals.

- GEC Durham Industries, Inc. 4/13/2022 $12,583.20
- GEC Durham Industries, Inc. 2/14/2022 $13,049.40

Audit found 2 entries in the GP GL with a description of “Precap Meter Installation” totaling $125,747.35. These entries were credited to the meter expense account and debited to account 8830-2-0000-10-1618-1070. Audit could not trace any similar entries in the SAP GL. Refer to the Plant section of this report regarding the pre-capitalization policy.

Account #587 Customer Installations Expenses $48,988 per the FERC Form 1 agrees with the filing schedule RR-2.1, RR-2.6 and the following SAP general ledger accounts:

50000010587000	Salaries and Wages	$ 45,670.48
50030010587000	Outside Svs	$ 1,050.00
50093010587000	Util Exp-Cust Instal	$ 219.64
50500010587000	Other Operating Exp	$ -0-
80000010587000	Lbr Alloc	$ 2,047.40
		$ 48,987.52

Customer Installation Expense $48,897.52 represents a 10% decrease from the 2021 year-end balance.

Account #588 Miscellaneous Expenses $1,613,700 per the FERC Form 1 agrees with the filing schedule RR-2.1 and RR-2.6 which reflected the following SAP general ledger accounts:

50000010588000	Salaries and Wages	$	290,214.80
50001010588000	Overtime	$	8,732.64
50005010588000	AllocCorp Lbr Leg	$	(27,089.68)
50010010588000	Vacation & Other TO	$	3,589.08
50030010588000	Outside Svs	$	91,348.32
50070010588000	Land&Property Rents	$	4,353.62
50121010588000	Fleet-Fuel	$	(28,298.54)
50230010588000	Facility Costs	$	93,201.47
50231010588000	Facility Costs-Maint	$	1,128.16
50232010588000	Facility Costs-Secur	$	90.00
50500010588000	Other Operating Exp	$	1,038,432.46
50510010588000	Cost Alloc to Cap	$	(3,314.56)
70200010588000	BS Lbr Offset	$	(5,092.63)
80000010588000	Lbr Alloc	$	111,641.00
80300010588000	Assess Lbr	$	264.70
80302010588000	Assess Material	$	2,630.46
80304010588000	Assess Other	$	865.28
80305010588000	Assess Fleet - Asses	$	63.12
80308010588000	Assess Meals	$	828.02
80308510588000	Assess Travel	$	3,022.44
85300010588000	Assess Lbr-Intrc	$	20,946.09
85303010588000	As Serv-Intrc	$	7,960.00
85311010588000	As OH BenIntrc	$	(1,816.41)
		$	1,613,699.84

Account 588 overall had a 31% increase in expenses in 2022 over calendar year 2021.

Audit reviewed the following 4 invoices:

	VENDOR	DATE		AMOUNT
1	Leighton A. White Complete Sitework Services	12/21/22	$	87,460.00
2	Wright Tree Service	12/27/22	$	11,793.80
3	USIC Locating Services LLC	7/31/2022	$	13,117.78
4	USIC Locating Services LLC	7/11/2022	$	12,746.24

The Leighton A. White Complete Sitework Service invoice showed that $87,460 worth of work out of a total contract of $252,460 was completed. The invoice specified what the project was for "West Lebanon future facility clean up" and that 12/14/2022 "work was completed App #2". The remaining invoices were for tree removal, flat fees for utility location and prevention services.

Audit reviewed 2 vegetation management accruals totaling $98,645.97. The vegetation management accruals are for vegetation management estimates based on previous invoices from 7 different vegetation management companies' and expenses incurred but not yet paid.

Account #590 Maintenance Supervision and Engineering $13,943 per the FERC Form 1, was verified to the general ledger account 8830-2-9854-56-5010-5990 from January 2022 through September 2022. That activity was rolled into SAP accounts, reflected on the filing schedule RR-2.6 as:

50000010590000	Salaries and Wages	$13,469
50010010590000	Vacation and Other TO	$ 175
50500010590000	Other Operating Exp	$ -0-
80000010590000	Lbr Alloc	$ 299
		$13,943

The account reflects a decrease of 5% over the year ending 12/31/2021.

In the Great Plains ledger, there were 65 entries reflecting weekly payroll entries, accruals and reversals. In the SAP general ledger there were 9 carry forward charges accurately reflecting the GP ending balance as of 9/30/23. There was also 2 payroll entries and 3 reclassification entries.

Account #591 Maintenance of Structures $129,865 per the FERC Form 1 represents a 5% decrease from 2022year end. The figure was verified to the filing schedule RR-2, and to the following general ledger accounts:

50000010591000	Salaries and Wages	$105,704.19
50010010591000	Vacation & Other TO	$ 41.18
50030010591000	Outside Svs	$ 790.00
50500010591000	Other Operating Exp	$ 20,630.32
80000010591000	Lbr Alloc	$ 2,698.90
		$129,864.59

The first account's activity reflected weekly payroll entries, accrual reversals, P-card entries and 2 vendor invoices.

Account #592 Maintenance of Station Equipment $238,334 per the FERC Form 1, was verified to the filing schedule RR-2 and to the following general ledger accounts:

50000010592000	Salaries and Wages	$ 131,558.74
50001010592000	Overtime	$ 1,410.85
50500010592000	Other Operating Exp	$ 77,510.98
80000010592000	Lbr Alloc	$ 27,853.81
		$ 238,334.38

Overall, the account decreased by 20% from the 2021 year-end balance. The SAP GL did not reflect any vendor invoices. In the former GP account 8830-2-0000-56-5210-5920 audit notes only 1 invoice for $731 was expensed. GP account 8830-2-9851-56-5010-5920 showed weekly payroll entries, accruals and reversals. Audit reviewed the activity in GP account 8830-2-9851-56-5210-5920 and noted the following:

Net accruals and reversals	$ 13,072.94
P-Card Expenses	$ 9,003.47
1 invoice AECOM Inc.	$ 7,900.00
1 invoice ARTHUR J. HURLEY CO., INC.	$ 582.50
1 invoice AVO MULTIAMP CORPORATION D/B/A MEGGER	$ 1,492.00
1 invoice COOPER POWER SYSTEMS	$ 1,132.44
1 invoice DENRON PLUMBING & HVAC DBA DENRON HALL	$ 595.00
2 invoices FIRST LINE ASSOCIATES INC	$ 1,110.51
3 invoices WW GRAINGER INC	$ 1,376.20
1 invoice GRANITE STATE PLUMBING & HEATING	$ 660.00
3 invoices HASTINGS FIBER GLASS PRODUCTS	$ 1,889.52
1 invoice KRISTEN LEHMAN	$ 80.00
1 invoice RAM PRINTING INC	$ 497.26
5 invoices TOWN OF SALEM NH	$ 7,433.50
7 invoices STAPLES BUSINESS ADVANTAGE	$ 5,805.78
16 invoices UNITED POWER GROUP, INC.	$ 34,855.00
4 invoices UNITED SITE SERVICES NORTHEAST INC	$ 1,561.86
2 invoices WEIDMANN ELECTRICAL TECHNOLOGY INC	$ 712.00
TOTAL EXPENSES THROUGH 9/30/22	**$ 89,759.98**

Account #593 Maintenance of Overhead Lines $5,452,702 per the FERC Form 1 represents an increase over the 2021 year-end balance of 18%. The 2022 was verified to filing schedule RR-2.6 associated with the following general ledger accounts. Audit verified the ending GP general ledger and the starting SAP balance.

24672010593000	Curr REC Obg Non-Reg	$ 3,675,811.00
50000010593000	Salaries and Wages	$ 568,816.34
50001010593000	Overtime	$ 4,281.72

50010010593000	Vacation & Other TO	$ 7,373.84
50030010593000	Outside Svs	$ 604,997.94
50123010593000	Fleet-Permit/Inspect	$ -0-
50330010593000	Misc Other Deduction	$ 2,423.97
50500010593000	Other Operating Exp	$ 3,510,153.97
80000010593000	Lbr Alloc	$ 754,654.22
		$ 9,128,513.00

As noted in **Audit Issue #1** and via response from the Company, $3,675,811.00 (shown above in GL REG account 24672010593000) should have been excluded from FERC account 593 and added to account 242. When this account is excluded, the remaining accounts shown in SAP account 593 match the filing amount of $ $5,452,702.00.

SAP account 50030010593000 included 585 charges and reversals or corrective entries for foresters/laborers, 4x4 vehicles, "laptops with software" and iPads. The 585 entries net total was $60,599.34. It is unclear why portions of these charges were reversed. There were also 145 various vendor invoices totaling $580,358.67.

Audit also found 3 credit entries related to storm costs entitled "Trans chrgs booked to Storm 2108 in error s/b 2208" and "Trans Stm 2209 Outside Services from exp to defer" that totaled ($37,379.46).

Furthermore, Audit found 2 debit entries in SAP Account 50030010593000 relating to disallowed storm costs. The first entry entitled "Per PUC Audit - Stm 2113 Costs Disallow – Transfer" totaled $1,200. Per the Audit Report issued on September 9, 2022 relating to Docket DE 22-019, the costs were related to 2 disallowed charges from Winter Storm Orlena in 2021, refer to Audit Issue #3. The second debit entry totaled $211.98 and was entitled "Per PUC Audit - Stm 2102 Costs Disallow – Transfer" was also related to Winter Storm Orlena, refer to Audit Issue #1 for further information on the disallowance of costs. Audit also found in GP general ledger account 8830-2-9851-56-5210-5932 an additional entry entitled "Trans Chrgs Storm 2102 to 2103" for $6,260.63. This disallowed storm cost was identified as Audit Issue #2 in the same Audit Report issued on September 9, 2022 for Docket DE 22-019. Audit recommends that all 3 debit entries be considered non-recurring. **Audit Issue #18**

Audit reviewed the activity in the GP general ledger and noted the following in regard to vendor transactions:

1 invoice AIDASH INC	$	42,000.00
3 invoices AIRGAS	$	750.46
1 invoice AMERICAN CRANE COMPANY	$	2,930.00
1 credit ARTHUR J. HURLEY CO., INC.	$	(25.00)
313 invoices ASPLUNDH TREE EXPERT CO	$	2,022,293.01
2 invoices BENCHMARK GRAPHICS	$	443.18
1 invoice SPENCER BROUILLETTE	$	12.99

50 invoices CHIPPERS	$ 167,158.75
1 voided invoice CLEARWAY INDUSTRIES LLC	$ (3,338.75)
7 invoices CONTROLPOINT TECHNOLOGIES INC	$ 4,792.05
1 invoice EG CAPITAL LLC	$ 2,779.31
1 invoice ELLIS WILLIAM C	$ 8.49
28 invoices THOMAS KEOUGH JR. DBA ENVIRO ARBOR SOLUTIONS, LLC	$ 430,394.22
5 invoices FIRESIDE HOTEL	$ 10,201.88
1 invoice ADAM FORTUNATI	$ 16.26
1 invoice SHAWN FUREY	$ 398.36
1 invoice WW GRAINGER INC	$ 352.92
1 invoice HEATHER GREEN	$ 264.00
3 invoices TOWN OF HUDSON NH	$ 3,097.50
48 invoices HUNTER NORTH ASSOCIATES LLC	$ 23,475.00
1 invoice I.C. REED & SONS, INC.	$ 18,995.47
7 invoices JCR CONSTRUCTION CO INC	$ 88,835.97
1 invoice KAMCO SUPPLY CORP OF BOSTON	$ 980.00
121 invoices LAKESIDE ENVIRONMENTAL CONSULTANTS INC	$ 204,402.97
3 invoices MALLORY SAFETY & SUPPLY	$ 605.00
32 charges for 99 RESTAURANT & PUB and 4 voided entries	$ 3,341.65
6 invoices NORTHEASTERN LAND SERVICES DBA THE NLS GROUP	$ 1,248.48
14 invoices NORTHERN TREE	$ 92,212.45
1 invoice ORR & RENO, P.A.	$ 1,447.00
1 invoice RICHARD PARADIE	$ 149.17
2 invoices PARKER FENCE	$ 25,800.00
2 invoices CALE PERRY	$ 236.45
1 invoice TREVOR REYNOLDS	$ 16.58
7 invoices TOWN OF SALEM NH	$ 13,704.00
4 invoices STUART C IRBY CO	$ 3,965.64
1 invoice TERRA SPECTRUM TECHNOLOGIES	$ 22,667.00
1 invoice TOWN OF HAMPSTEAD	$ 316.00
22 invoices TYNDALE COMPANY INC	$ 6,306.65
2 invoices UNITED PARCEL SERVICE	$ 62.93
8 invoices UTILITY SERVICE & ASSISTANCE INC	$ 142,251.29
4 invoices VANASSE HANGEN BRUSTLIN INC	$ 13,898.34
19 invoices WRIGHT TREE SERVICE, INC	$ 287,369.91
1 invoice HART HALSEY LLC DBA EXTRA DUTY SOLUTIONS	$ 584.34
TOTAL VENDOR INVOICES THROUGH 9/30/22	**$ 3,637,401.92**

Audit requested supporting documentation for the largest invoice from Asplundh Tree Expert, Co. which totaled $333,319.96. The invoice was part of a 2021 contact totaling $551,986.77. $218,666.81 was paid in 2021 for mileage reimbursement for May – August 2021.

A note on the invoice indicated an incorrect invoice was received in November 2021 and adjustments were needed. The note further indicated that a corrected invoice was received 2/16/2022 and "entered 2/21/2022". The adjustment included a credit in the amount of $7,445.21 on the mileage already paid for in 2021. Audit confirmed a debit accrual in the amount of $281,017.96 was recorded in 2021 related to this contract. The credit entry was posted in 2022 leaving the balance of $52,302 of expenses paid in 2022 for 2021 costs. **Audit Issue #19**

Account #594 Maintenance of Underground Lines $167,310 per the FERC Form 1 represents an increase of 664% over the 2021 year-end figure. The total was verified to filing schedule RR-2, which reflects following general ledger accounts:

50000010594000	Salaries and Wages	$ 22,177.85
50030010594000	Outside Svs	$ 124,713.40
50500010594000	Other Operating Exp	$ 7,249.96
80000010594000	Lbr Alloc	$ 13,168.88
		$ 167,310.09

The GP general ledger reflected 75 payroll entries and 18 accruals and reversals. There were 5 invoices from 4 different vendors totaling $8,050.24 and 4 credit entries for various work orders that totaled ($6,701.08).

In SAP account 50030010594000 Audit tested the 3 largest invoices which were from the same vendor, Granite State Cable Splicing & Testing, LLC and together totaled $116,162.00. Work was performed between 10/1/22 – 12/19/22 and included excavation, underground cable replacement, hydroseed and loam, concrete repair or maintenance, PVC conduit, and the use of dump trucks or pull trucks, in addition to labor charges. The work appeared appropriate for the charges incurred.

Account #595 Maintenance of Line Transformers $3,701 per the FERC Form 1 represents an overall decrease of 90% from 2021. The 2022 total was verified to the filing schedule RR-2 and to SAP general ledger account 50000010595000.

The only transactions in the SAP general ledger were carry forward charges from the GP general ledger with no new transactions after 9/30/22. The GP general ledger consisted of 29 payroll entries summing to $4,095.43 and 5 accrual entries totaling ($394.80).

Account #596 Maintenance of Street Lighting and Signal Systems $39,278 per the FERC Form 1 is a decrease of 8% from calendar year 2021. The total agrees with the filing schedule RR-2 and was verified to the following SAP general ledger accounts:

50000010596000	Salaries and Wages	$ 27,114.73
50010010596000	Vacation & Other TO	$ 30.96
50500010596000	Other Operating Exp	$ 1,992.00
80000010596000	Lbr Alloc	$ 10,140.74
		$ 39,278.43

Transactions consisted of weekly payroll entries, payroll accruals and 1 vendor invoice for Hunter North Associates, LLC summing to $380.00.

Account #597 Maintenance of Meters $53,762 per FERC Form 1 and the filing schedule RR-2 was verified to the following general ledger accounts:

50000010597000	Salaries and Wages	$ 26,822.80
50001010597000	Overtime	$ 77.68
50500010597000	Other Operating Exp	$ 11,202.33
80000010597000	Lbr Alloc	$ 15,658.98
		$ 53,761.79

The 12/31/2022 total represents an increase from the 12/31/2021 balance by 19%. The GP general ledger reflected 80 payroll entries, 16 payroll accrual entries, 10 vendor invoices and 1 P-card entry. The Salaries and Wages account 50000010597000 reflects 10 carry forward charges from the GP general ledger however 1 entry is dated 10/31/22. There was also 1 transaction coded only as “SA” with a description of “Timesheet Conversion”. According to the Company. The code SA translates to a ”G/L Account Document”. In account 80000010597000 Labor Allocation account, all 80 entries in the account were coded as “WF” which translates to “WFS Integration”.

Account #598 Maintenance of Miscellaneous Distribution Plant $59,472 per the FERC Form 1 represents an increase of 25% from the prior year. The amount was verified to the filing schedule RR-2.6 and to the following SAP general ledger accounts:

50000010598000	Salaries and Wages	$29,806.32
50030010598000	Outside Svs	$ 4,544.74
50330010598000	Misc Other Deduction	$ 340.96
50500010598000	Other Operating Exp	$24,780.36
		$59,472.38

The SAP general ledger reflected 3 reclassification entries and 3 vendor invoices totaling $4,885.70 and 18 carry forward entries from the GP general. The GP general ledger reflected 112 weekly payroll entries, 11 vendor invoices summing to $14,085.38, 8 P-Card expenses, and 1 reclassification entry. Audit requested supporting information for the largest invoice from Bashlin Industries, Inc. totaling $11,779.30. The charge was an accrual of a total of 10 invoices for materials and freight. Invoices included costs for materials such as linemen body harnesses, linemen belts, climber pads and aluminum pole climbers. 1 invoice totaling $465.10 (invoice number 323443) has a “shipped date” of 3/28/2023 which would be outside of the test year of 2022 The invoice does not reflect when the order was placed. **Audit Issue #19**.

Customer Account Expenses, per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Customer Account Expenses decreased 5%.

		12/31/2021	12/31/2022	% change
901	Supervision	$ 48,490.00	$ 45,592.00	-6%
902	Meter Reading Expenses	$ 345,953.00	$ 353,272.00	2%
903	Customer Record and Collection Expenses	$1,129,379.00	$1,049,339.00	-7%
904	Uncollectible Accounts	$ 281,647.00	$ 272,932.00	-3%
905	Miscellaneous Customer Accounts Expenses	$ 29,720.00	$ 20,000.00	-33%
	Total Customer Accounts Expenses	**$1,835,189.00**	**$1,741,135.00**	**-5%**

Each of the 90x accounts was verified to the filing schedule RR-2 and to the general ledger.

Account #901 Supervision $45,592 per the FERC Form 1 represents a decrease over the 2021 balance of 6%. The total was verified to the RR-2 schedule in the filing, and was tied to the general ledger accounts:

50000010901000	Salaries and Wages	$ 36,295.35
50001010901000	Overtime	$ (169.68)
50500010901000	Other Operating Exp	$ 0
80000010901000	Lbr Alloc	$ 9,502.08
		$ 45,591.75

Activity in the account was noted to be bi-weekly payrolls. Please see the *Payroll* section above for additional payroll information.

Account #902 Meter Reading Expenses $353,272 per the FERC Form 1 represents a decrease of 2% over the prior year. The total was verified to the RR-2 schedule in the filing, and was tied to the general ledger accounts:

50000010902000	Salaries and Wages	$ 260,785.24
50001010902000	Overtime	$ 83.03
50030010902000	Outside Svs	$ 47,148.93
50500010902000	Other Operating Exp	$ 1,739.87
80000010902000	Lbr Alloc	$ 43,514.76
		$ 353,271.83

The GP ledger reflected weekly payroll entries, payroll accruals and reversals, 12 invoices from CGI Technologies & Solutions totaling $94,635.60, 1 invoice from Honeywell Mercury Instruments summing to $867.

The SAP GL reflected 5 invoices totaling $56,498.93, 250 payroll entries totaling $46,548.58 and 5 reclassification entries.

Account 903 Customer Records and Expenses $1,049,339 was verified to the filing schedule RR-2 and to the FERC Form 1. The expense represents a 7% decrease from the 2021 total. Audit verified the 2022 figure to the following general ledger accounts:

50000010903000	Salaries and Wages	$	503,919.70
50001010903000	Overtime	$	8,966.19
50005010903000	AllocCorp Lbr Leg	$	(17,824.27)
50006010903000	AllocReg Lbr Leg	$	7,604.30
50010010903000	Vacation & Other TO	$	(399.22)
50030010903000	Outside Svs	$	17,749.96
50150010903000	Advertising Expenses	$	1,976.55
50240010903000	Legal Expenses	$	40.82
50500010903000	Other Operating Exp	$	(1,590.23)
50507010903000	Cust Rec&Cltn Exp	$	421,546.05
50510010903000	Cost Alloc to Cap	$	(63,230.85)
70200010903000	BS Lbr Offset	$	(1,082.76)
80000010903000	Lbr Alloc	$	162,460.90
80300010903000	Assess Lbr	$	(10,375.58)
80304010903000	Assess Other	$	520.74
80308010903000	Assess Meals	$	345.79
80308510903000	Assess Travel	$	823.85
80311010903000	Assess OH Benefit	$	62.54
85300010903000	Assess Lbr-Intrc	$	20,176.13
85304010903000	Assess Other-Intrc	$	8.09
85308010903000	Assess Meals -Intrc	$	49.01
85311010903000	As OH BenIntrc	$	(2,408.96)
			$1,049,338.75

The GP general ledger reflected 1,872 weekly payroll entries totaling $414,777.15, payroll accruals and reversals. There were also 90 entries totaling $3,927.44 entitled IC: CS0NH, Journal:XXXXXXX CCSM-PYMT, that the Company has previously indicated were transactions that are "good faith" courtesy adjustments to customers' bills for the reversal or forgiveness of certain charges, including late payment charges, connection fees, minor balances, etc. Some of the higher dollar subtotals for vendor invoices were the following:

27 invoices FISERV	$237,606.26
18 invoices PITNEY BOWES	$ 9,546.94
8 invoices LANGUAGE LINE SERVICES, INC.	$ 8,633.51
14 invoices EQUIFAX INFORMATION SVCS LLC	$ 5,112.10
	$260,898.81

The SAP General ledger reflected 35 vendor invoices totaling $19,092, 53 payroll entries totaling $9,201.61, payroll accrual and reversals, reclassifications and 6 entries related to customer surveys that totaled $8,381.75.

<u>Account 904 Uncollectible Accounts</u> $272,931.99 (rounded per the FERC Form 1) was verified to the filing as part of the overall schedule RR-2.7. RR-3.10, the Uncollectible Expense Factor Workpaper reflects the 2022 Uncollectible Expense as $486,165. It is unclear from where that figure was derived. Audit compared the changes in the account 904 since the prior 2018 rate case, and notes the following:

		12/31/2019		12/31/2020		12/31/2021		12/31/2022	
904	Uncollectible Accounts	$ 152,841	123%	$ 233,314	53%	$ 281,647	21%	$ 272,932	-3%

2019 was the first year after the previous test year, and saw a 123% increase in the Uncollectible Accounts expense account 904. 2020 reflected a 53% increase over the 2019 expense figure, the 2021 reflected a 21% increase over 2020. The test year saw a modest 3% decrease over the 2021 figure.

Audit reviewed the 2022 Great Plains and SAP accounts and related activity:
Great Plains activity January through September 2022:

8830-2-9865-80-8660-9040	Uncollectible Accounts	$ 401,970.76
8830-2-0000-80-8660-9041	Bad Debt Expense – Commodity	<u>$(159,548.61)</u>
	Activity through September 30, 2022	$ 242,422.15

The net Great Plains activity was rolled into SAP account 502000904. At year-end, the Uncollectible Expense total of $272,931.99 was the sum of:

Bad Debt Write-off	10904000 Uncoll A/cs—FERCE 502000904	$ 188,737.33
Bad Debt IVA	10904000 Uncoll A/cs—FERCE 502010904	$ 1,391,495.49
Bad Debt Manual Adj	10904000 Uncoll A/cs—FERCE 502020904	<u>$(1,307,300.83)</u>
	FERC Form 1, account 904	$ 272,931.99

Audit requested clarification or Bad Debt IVA, and was told that the Individual Value Adjustments (IVA) account in SAP "*automatically calculates and processes journal entries for bad debt expense. This automatic calculation is reversed on a monthly basis, manually calculated, and a new journal entry is processed.*" Offsets to the Great Plains Uncollectible Accounts -8660-9040 $401,970.76 were credited to the Reserve for Bad Debt Accrual, account 8830-2-0000-10-1102-1443, which was rolled into SAP account 11020010144000, Provision for Uncollectible Accounts. At 9/30 2022 the Great Plains balance in the -1443 account was $(873,859.15). At 12/31/2022, that balance reflected $(2,361,544.29)

Activity in the Great Plains Bad Debt Expense-Commodity account 8830-2-0000-80-8660-9041, reflected monthly credits relating to Commodity over/under calculations. Offsets were booked to 8830-2-0000-10-1101-1423 A/R Under Collect-Default/LR Sv. The balance of the GP -1423 account at 9/30/2022 was $2,127,657.97. The roll forward into SAP was combined with account 8830-2-0000-10-1101-1429 A/R REC Obligation $3,675,811.00 for a total SAP beginning balance of account 13080010142000 of $5,803,468.97.

Account 905 Miscellaneous Customer Accounts Expenses $20,000 was verified to the filing schedule RR-2 and to the FERC Form 1. The expense represents a 33% decrease from the 2021 total. Audit verified the 2022 figure to the following SAP general ledger accounts:

50000010905000	Salaries and Wages	$16,000.00
50030010905000	Outside Svs	$ 4,000.00
50500010905000	Other Operating Exp	$ -0-
		$20,000.00

Between both GP and SAP general ledger the only transactions were 10 payments to Phoenix Electronic Business Solutions, LLC dba Systrends USA, each totaling $2,000 and 2 reclassification entries.

Customer Service and Information Expenses per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Customer Service and Information Expenses decreased 33%.

		12/31/2021	12/31/2022	% change
909	Informational and Instructional Expenses	$ 72,065.00	$ 97,960.00	36%
910	Miscellaneous Customer Service and Informational Expenses	$ 1,482.00	$ -	-100%
	Total Customer Service and Informational Expenses	**$ 73,547.00**	**$ 97,960.00**	**33%**

Account 909 Informational and Instructional Expenses $97,960 per the FERC Form 1 represents a decrease of 36% from the 2021 balance. Audit verified the $97,960 to the following SAP general ledger accounts:

50000010909000	Salaries and Wages	$ 24,257.33
50150010909000	Advertising Expenses	$ 61,557.67
50500010909000	Other Operating Exp	$ 10,688.00
85400010909000	WBS ST Lbr-Intrc	$ 1,296.64
85404010909000	WBS ST Other-Intrc	$ 160.60
		$ 97,960.24

Between both the GP and SAP general ledger, entries consisted of weekly payroll, payroll accruals and reversals, marketing accruals and 22 vendor invoices totaling $45,823.43. Audit tested one of the largest transactions for $21,000 entitled “NHE July 2022 Rates Mailing”. The expense was for a July mailing to customers that included the printing, proofs, folding, postage and mailing of letters to customers.

Sales Expenses per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Sales Expenses decreased 24% and was verified to filing schedule RR-2.

		12/31/2021	12/31/2022	% change
912	Demonstrating and Selling Expenses	$ 150.00	$ (10,827.00)	-7318%
913	Advertising Expenses	$ 252.00	$ -	-100%
916	Miscellaneous Sales Expenses	$ 208,419.00	$ 170,411.00	-18%
	Total Sales Expense	**$ 208,821.00**	**$ 159,584.00**	**-24%**

Account 912 Demonstrating and Selling Expenses ($10,827) is the sum of the following SAP general ledger accounts and was verified to RR-2 of the filing and FERC Form 1:

50000010912000	Salaries and Wages	$ 12,608.86
50005010912000	AllocCorp Lbr Leg	$ (4,283.25)
50010010912000	Vacation & Other TO	$ 3,369.69
50150010912000	Advertising Expenses	$ 882.12
50400010912000	AllocCorp Cap Leg	$ 318.00
50500010912000	Other Operating Exp	$(18,567.55)
50510010912000	Cost Alloc to Cap	$(22,392.47)
70200010912000	BS Lbr Offset	$ (3,222.09)
80000010912000	Lbr Alloc	$ 26,080.16
80300010912000	Assess Lbr	$(10,133.92)
80308510912000	Assess Travel	$ 230.62
85300010912000	Assess Lbr-Intrc	$ 4,560.92
85311010912000	As OH BenIntrc	$ (277.67)
		$(10,826.58)

The GP general ledger only consisted of 2 invoices from Jill M. Fitzpatrick totaling $882.12. The SAP general ledger however consisted of numerous credit entries labeled as marketing, payroll interest corrections, missed A&G assessments and true ups resulting in a large credit balance at the end of 2022. Audit questioned the Company as to the reason why there were so many entries as in previous years entries have always consisted of small vendor invoices and resulted in an overall -7318% decrease from calendar year 2021. The Company responded with the following:

The credit balance in FERC account 912 is mainly due to a correcting journal entry that was recorded in December 2022. Upon migration to SAP, the systems support team identified that the automatic template used to calculate capital costs had not processed correctly for October and November 2022, hence a reclass entry was done to correct the missed costs.

Audit is unsure if the automatic template has been corrected or if other template mitigations were processed correctly **Audit Issue #20**

Account 916 Miscellaneous Sales Expenses $ 170,411 was the FERC Form 1 balance and verified to filing schedule RR-2 and the following SAP general ledger accounts:

50000010916000	Salaries and Wages	$ 167,170.03
50150010916000	Advertising Expenses	$ 3,240.90
		$ 170,410.93

Account 916 shows an overall 18% decrease in expenses from 2021. The GP general ledger consisted of payroll entries, accrual sand reversals and the following vendor invoices:

1 invoice ARAMARK UNIFORM AND CAREER APPAREL LLC	$ 56.97
1 invoice DINA SYLVESTER	$ 52.98
8 invoices JILL M. FITZPATRICK	$ 1,360.95
2 invoices GREATER SALEM CHAMBER OF COMMERCE	$ 975.00
	$ 2,445.90

Audit notes that the only entries in the SAP general ledger are carry forward charges.

Administrative and General Expenses per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Administrative and General Expenses increased 77%.

	12/31/2021	12/31/2022	% change
920 Administrative and General Salaries	$ 2,883,082.00	$ 2,877,428.00	0%
921 Office Supplies and Expenses	$ 1,425,717.00	$ 2,287,231.00	60%
922 Administrative Expenses Transferred-Credit	$ (11,574,397.00)	$ (8,002,460.00)	-31%
923 Outside Services Employed	$ 3,048,900.00	$ 2,381,415.00	-22%
924 Property Insurance	$ 1,572,228.00	$ 1,589,317.00	1%
925 Injuries & Damages Insurance	$ 800,546.00	$ 927,599.00	16%
926 Employee Pensions & Benefits	$ 4,713,113.00	$ 3,697,502.00	-22%
928 Regulatory Commission Expenses	$ 547,366.00	$ 643,455.00	18%
930 Miscellaneous General Expenses	$ 61,330.00	$ (115,412.00)	-288%
931 Rent	$ 192,391.00	$ 205,469.00	7%
Total Administrative and General Operation Expenses	$ 3,670,276.00	$ 6,491,544.00	77%
935 Maintenance of General Plant	$ -	$ 7,320.00	100%
Total Administrative and General Maintenance Expenses	$ -	$ 7,320.00	100%
Total Administrative and General Expenses	**$ 3,670,276.00**	**$ 6,498,864.00**	**77%**

920 Administrative and General Salaries $2,877,428 per the FERC Form 1 represents a 0% change over the 2022 FERC Form 1 balance. The filing schedule RR-2.10, however, reflects $2,859,282, or $18,146 *less* than the FERC Form 1. The year end general ledger balance for 2022 was $2,618,649. The Company indicated that there were “mapping issues” when the Great Plains accounts were rolled into SAP on October 1, 2022. **Audit Issue #1**

A total of fifty-eight SAP general ledger account summed to the year-end GL total of $2,618,649.

50000010920000	Salaries and Wages	$725,045.00
50001010920000	Overtime	$1,942.32
50005010920000	AllocCorp Lbr Leg	$211,155.85
50006010920000	AllocReg Lbr Leg	$219,794.08
50010010920000	Vacation & Other TO	$(135,238.04)
50011010920000	SS/CPP/Emp Pension	$175.06
50011510920000	Ben Offst	$(69,745.72)
50012010920000	Unemp/Emp Insurance	$289.02
50015010920000	Medicare/Healthcare	$732,170.83
50017010920000	Group/Emp Ben	$9,791.79
50021010920000	LTIP	$48,550.53
50022010920000	Bonuses	$600,095.85
50050010920000	Equip & Machin Rents	$2,492.98
50122010920000	Fleet-Repair/Main	$34,387.80
50123010920000	Fleet-Permit/Inspect	$6,096.25
50254010920000	Prof Svs-Other	$10,780.84
50330010920000	Misc Other Deduction	$(4,155.20)
50500010920000	Other Operating Exp	$7,644.74
50510010920000	Cost Alloc to Cap	$(688,081.34)
50520010920000	AllocCorp NonLbr Leg	$(2,097.19)
50521010920000	AllocReg NonLbr Leg	$164,053.48
50550010920000	Collection System	$-
56104010920000	Amrt Fn Cst-Debt Dis	$436.52
59000010920000	Current FIT Exp	$-
59001010920000	Current SIT Exp	$-
59021010920000	Deferred FIT Exp	$-
59023010920000	Deferred Amrt EADIT	$-
70200010920000	BS Lbr Offset	$(8,392.44)
70211010920000	BS Ops OH Benefit	$(64,341.26)
80000010920000	Lbr Alloc	$247,748.73
80200010920000	Settle Lbr	$(29,403.31)
80202010920000	Settle Material	$(4,800.31)
80203010920000	Settle Services	$(656,848.01)
80300010920000	Assess Lbr	$8,392.44
80311010920000	Assess OH Benefit	$(127,913.92)
80311210920000	Assess Payroll Tax	$(9,139.79)
80311310920000	Assess Pension/OPEB	$360.81
80311410920000	Assess Prop Ins	$647.97
85300010920000	Assess Lbr-Intrc	$185,464.24
85302010920000	As Mat -Intrc	$1,231.24
85303010920000	As Serv-Intrc	$11,405.50
85304010920000	Assess Other-Intrc	$15,766.43
85308010920000	Assess Meals -Intrc	$83.33
85308510920000	Assess Travel-Intrc	$259.31
85311010920000	As OH BenIntrc	$12,222.54
85311210920000	As Prl Tx-Intrc	$2,119.78

85400010920000	WBS ST Lbr-Intrc	$(45,842.82)
85402010920000	WBS ST Mat-Intrc	$531.10
85403010920000	WBS ST Serv-Intrc	$487,794.12
85404010920000	WBS ST Other-Intrc	$524,241.09
85405010920000	WBS ST Fleet-Intrc	$27.34
85408010920000	WBS ST Meals-Intrc	$276.78
85408510920000	WBS ST Travel-Intrc	$775.59
85411010920000	WBS ST OH Ben-Intrc	$184,637.63
85411210920000	WBS ST OH PrlTx-intr	$1,270.30
85411310920000	WBS ST OH Pn/OPEB-in	$2,329.38
85411410920000	WBS ST OH PrIn-Intrc	$191.16
85411610920000	WBS ST Vaca-Intrc	$1,968.33
		$2,618,648.73

Audit reviewed the salaries and wages, overtime, labor allocation, vacation, pension and other payroll associated general ledger accounts during the detail review of payroll. See the *Payroll* section of this report for a detailed review.

Account 50500010920000, Other Operating Expense, contained 84 entries totaling $7,645. All 84 entries were to reclassify the expense to the correct regulatory account.

Account #921 Office Supplies and Expenses $2,287,231 per the FERC Form 1 does not agree with the filing or general ledger. Filing Schedule RR-2.10 lists $1,600,180 creating a $687,051.13 variance between the filing and FERC Form 1. The Company explained that the variance further:

"Schedule RR-2 includes an additional adjustment of $(687,051) to capitalize 85% of the physical inventory write-off that was recorded for GAAP purposes. This capitalized amount was not recorded for GAAP purposes to align with the Parent Company (APUC) Form 10-K filing and not have differences between those GAAP filings. This amount is correctly presented in the Revenue Requirement." **Audit Issue #1**. (underline added)

Furthermore, the variance between the FERC Form 1 and the SAP general ledger was related to mapping issues, reportedly $12,444.13 associated with Miscellaneous Current and Accrued Liabilities account 242 should have been mapped to account 921, and $14,040.00 in 921 should have been mapped to 107 CWIP **Audit Issue #1**.

Moreover, 1 SAP account was mapped to account 50320010999999, an unsettled WSB (Dues and Memberships) instead of 50320010921000 resulting in an immaterial difference of $50.85 between the Great Plains ending balance ledger as of 9/30/22 and the SAP starting ledger as of 9/30/22.

Overall, there was a 60% increase in expenses over the 2021 balance The SAP general ledger accounts, consisted of the following 43 accounts:

50030010921000	Outside Svs	$	7,125.32
50040010921000	Materials & Supplies	$	9,907.51
500400#	Materials & Supplies	$	-0-
50040510921000	M&C-NonStck Cntrl	$	9,667.95
50041010921000	M&C-Small Tools	$	66.09
50042010921000	M&C-Safety Supplies	$	4,790.63
50043010921000	M&C-Main Parts	$	101.52
50049510921000	M&C-Inventory Diff	$	808,295.01
500495#	M&C-Inventory Diff	$	-0-
50090010921000	Util Exp-Water & Sew	$	3,376.27
50092010921000	Util Exp-Heat & Elec	$	11,026.47
50110010921000	Trvl Exp	$	33,833.34
50111010921000	Trvl Exp-Accomm	$	2,532.20
50112010921000	Trvl Exp-Airfare	$	3,629.47
50113010921000	Trvl Exp-Rental	$	2,554.34
50114010921000	Trvl Exp-Mileage	$	1,538.52
50122010921000	Fleet-Repair/Main	$	-0-
50130010921000	Meals & Ent	$	8,081.59
50140010921000	Comm Exp-Telephone	$	754,436.79
50141010921000	Comm Exp-Cellular	$	78.92
50142010921000	Comm Exp-Internet	$	346.90
50210010921000	Comp Exp	$	1,355.97
50211010921000	Comp Exp-Repair	$	29,516.65
50213010921000	Comp Exp-Software	$	(36,569.35)
50270010921000	Office Related Exp	$	318,866.75
50271010921000	Postage	$	12.67
50300010921000	Rental Expense	$	9,872.00
50311010921000	Training	$	38,256.09
50320010921000	Dues & Memberships	$	40,465.37
50500010921000	Other Operating Exp	$	2,321.67
55057010921000	Cap Depr-Fleet	$	(35,406.70)
55110010921000	Unrealized Gns/Lss	$	(1,984.51)
56001010921000	Bank Charges	$	428.59
80000010921000	Lbr Alloc	$	1,264.44
80117010921000	OH A&G N-Labr	$	12,444.13
85302010921000	As Mat -Intrc	$	3,656.44
85304010921000	Assess Other-Intrc	$	271,502.90
85305010921000	As Fleet - Intrc	$	(20.90)
85308010921000	Assess Meals -Intrc	$	4,223.51
85308510921000	Assess Travel-Intrc	$	11,427.42
85400010921000	WBS ST Lbr-Intrc	$	10,887.71

85403010921000	WBS ST Serv-Intrc	$ (1,260.00)
85404010921000	WBS ST Other-Intrc	$ (28,934.43)
		$ 2,313,715.26

Audit is unsure of the significance of accounts 500400# or 500495# (highlighted in the table above) but there was no activity in either account.

Audit reviewed the GP general ledger and notes the following information in 8 subaccounts:

Office Supplies 9210 $170,564.39	
8830-2-9800-69-5130-9210	$ 73,110.45
8830-2-9810-69-5130-9210	$ 4,125.57
8830-2-9815-69-5130-9210	$ 3,483.90
8830-2-9820-69-5130-9210	$ 23,658.31
8830-2-9823-69-5130-9210	$ 1,604.93
8830-2-9825-69-5130-9210	$ 13,461.75
8830-2-9830-69-5130-9210	$ 22,248.40
8830-2-9835-69-5130-9210	$ 0.88
8830-2-9850-69-5130-9210	$ 142.02
8830-2-9851-69-5130-9210	$ 5,160.77
8830-2-9853-69-5130-9210	$ 1,136.78
8830-2-9854-69-5130-9210	$ 12,112.31
8830-2-9860-69-5130-9210	$ 4,822.92
8830-2-9865-69-5130-9210	$ 5,495.40
Subtotal of Accounts 9210	$170,564.39

Entries included p-card expenses, $6,269.09 in bank fees, 629 vendor invoices totaling $147,611.59 from vendors such as Staples, Hewlett-Packard Financial, Balance Professional, Inc., Comcast, Energy Tools, Inc. and PC Connection and Softchoice Corporation. Audit requested supporting documentation for 4 of the largest invoices from Verizon Wireless, PC Connection, Softchoice Corporation and Dell Latitude. The invoice from Verizon Wireless totaled $72,342.07 however only $21,702.62 was allocated to GSE. Charges were for phone usage for 845 cell phones and was posted to GP account 8830-2-9800-69-5131-9213.

The charge from PC Connection totaled $9,950.53. The charge was an allocation of 2 PC Connection invoices totaling $32,374.26. The Company provided that the GSE allocated portion of these invoices was $9,712.28 resulting in a $238.25 variance to what was recorded 8830-2-9800-69-5130-9210. **Audit Issue #21** The invoices included charges for two 100-inch professional Sony LED 4K and accessories for the screens, such as wall mounts and microphones.

The invoice from Softchoice (invoice #90550764) although requested, was not originally provided. The only information Audit was provided was the amount of the invoice totaling $16,250 and that that the invoice was dated 2/14/22. Further information subsequently provided shows a purchase of ten “Dell Latitude 7420”. A transaction entitled “Dell Latitude 7430 Btx Laptops-Install” totaling $14,040.00 was also reviewed. The supporting invoice was from Softchoice and was for 9 laptops each $1,560.

Travel 9211 $17,159.98

8830-2-9800-69-5131-9211	$ 362.70
8830-2-9810-69-5131-9211	$ 1,787.00
8830-2-9815-69-5131-9211	$ 4,088.47
8830-2-9820-69-5131-9211	$ 317.25
8830-2-9825-69-5131-9211	$ 6.11
8830-2-9850-69-5131-9211	$ 2,140.62
8830-2-9851-69-5131-9211	$ 1,540.82
8830-2-9854-69-5131-9211	$ 3,694.91
8830-2-9860-69-5131-9211	$ 3,222.10
Subtotal of Accounts 9211	$ 17,159.98

The overall 31 entries included direct non-labor accruals, p-card expenses, specific job reimbursements. Due to timing, further support for these invoices was not requested.

Utilities 9212 ($44.77)

8830-2-0000-69-5131-9212	$ (101.84)
8830-2-9800-69-5131-9212	$ 57.07
Subtotal of Accounts 9212	$ (44.77)

Communication 9213 $652,953.62

8830-2-9800-69-5131-9213	$555,529.01
8830-2-9820-69-5131-9213	$ 43.52
8830-2-9853-69-5131-9213	$ 97,381.09
Subtotal of Accounts 9213	$652,953.62

There were 262 vendor entries to vendor such as Breezeline, Cen-Com, Comcast, Consolidated Communications, DTN, LLC, Time Warner Cable, Verizon Business Solutions and Windstream. There were also intercompany cell phone charges and amortization of pre-paid expenses.

Dues & Membership Fees 9214 $ $33,699.77

8830-2-9815-69-5131-9214	$ 1,234.07
8830-2-9825-69-5131-9214	$ 50.85
8830-2-9854-69-5131-9214	$ 208.00
8830-2-9860-69-5131-9214	$ 23,449.35
8830-2-9868-69-5131-9214	$ 8,757.50
Subtotal of Accounts 9214	$ 33,699.77

Memberships included NH Home Builders Association, the Rotary Club of Great Salem, the New Hampshire Sustainable Energy Association dba Clean Energy NH and the Greater Portsmouth CC dba Chamber Collaborative Greater Portsmouth among other associations.

Training 5131-9215 $13,398.78	
8830-2-9800-69-5131-9215	$ 118.44
8830-2-9810-69-5131-9215	$ 2,144.03
8830-2-9812-69-5131-9215	$ 4,177.38
8830-2-9815-69-5131-9215	$ 3,017.12
8830-2-9820-69-5131-9215	$ 17.40
8830-2-9851-69-5131-9215	$ 1,074.75
8830-2-9854-69-5131-9215	$ 2,849.66
Subtotal Accounts 5131-9215	$13,398.78

Office Supplies – Head Office 5130-9215 $102,504.61	
8830-2-9800-69-5130-9215	$ 97,702.89
8830-2-9811-69-5130-9215	$ 3,126.13
8830-2-9815-69-5130-9215	$ 443.11
8830-2-9820-69-5130-9215	$ 36.63
8830-2-9850-69-5130-9215	$ 835.91
8830-2-9865-69-5130-9215	$ 257.06
8830-2-9868-69-5130-9215	$ 102.88
Subtotal of Accounts 5130-9215	$102,504.61

Meals and Entertainment 9216 $340.53	
8830-2-9835-69-5130-9216	$ 28.56
8830-2-9851-69-5130-9216	$ 256.59
8830-2-9860-69-5130-9216	$ 20.99
8830-2-9865-69-5130-9216	$ 34.39
Subtotal of Accounts 9216	$ 340.53

In the SAP general ledger, as noted earlier in this report, entries are identified by a coding system. There were 19 entries coded to "AB" which is an "accounting document". 18 of the entries posted to account 55110010921000 (Unrealized Gains/Losses) and totaled $5,953.53 with the description "Valuation on 20221231". The remaining entry totaling $ $16,012.48 was a corrective entry posted to account 50500010921000 with the description "Correct Reg Account for 804085".

There were 230 carry forward entries coded as "CF" totaling $1,018,372.02 which is $50.85 less than the GP ending balance of $ 1,018,422.87 as discussed previously in this section.

SAP Code "CO" which is described as "CO Posting" consisted of 2,047 entries that totaled $283,926.78 and posted to various accounts all beginning with an 8XXXXX prefix. Entries consisted of descriptions such as treasury transactions, HR, legal, shared costs with company 3070. 16 entries entitled "AUD_SAP AUD SAP Companies" and totaled $28,890.17. Other entries were described as business development, customer care service, communications, compliance, corporate IT, “Director fee and Ins SAP co”, environmental compliance, 62 entries entitled Executive or “Executive Service” or “Executive Offices” that totaled $10,399.64. Furthermore $4,921.09 was booked to various accounts as investor relations, 44 entries totaling $161,267.25 labeled as “Miscellaneous General” or “SAP Misc Cost SAP Companies”, 93 entries entitled “Ops General” or “Ops General Service” totaling $13,393.09, 30 payroll entries totaling $1,848.17, 121 entries described as “Regulatory” or “Regulatory Compliance” that total $4,618.91, 21 entries labeled as “TOT Rewards” summing to $4,126.47, and 4 entries “Energy Procurement Office Supplies” totaling $10,877.71.

There were 253 entries coded to “KR” which translates to a vendor invoice and totaled $149,965.10. Entries were posted to various 500XX accounts with limited further descriptions such as legal, finance, procurement, engineering, HR, IT or Corporate IT, and “Facilities Utilities”. Audit requested supporting documentation for 3 “KR” entries posted to SAP account 50140010921000 (Comm Exp-Telephone) totaling $54,321.37. All three invoices were for Verizon Wireless and in total summed to $181,071.22 which also showed as past due. The GSE portion was 30% of each individual invoice which include standard phone charges.

There was only 1 entry coded to “SA” which is a “G/L Document” and was a credit entry of $55,291.00. This amount appears to correspond to another entry coded to “WE” or “Goods Receipt” which Audit followed up with the Company for further information. The Company clarified this as a charge from Lebanon Ford for fleet repair and maintenance.

Audit also found there were 33 entries coded as “WA” or “Goods Issue” and totaled 9,907.51 and were only posted to account 50040010921000 (Materials and Supplies). There were also 52 entries coded to “WE” as discussed above is Goods Receipt” and totaled $82,189.93. There were 5 entries labeled as “WF” or “WFS Integration” that totaled $1,264.44 and all posted to account 80000010921000. Lastly, there were 434 entries coded to “WI” which translates to “Inventory Document” and totaled the largest amount of $803,038.67. All entries posted to account 50049510921000.

Account #922 Administrative Expenses Transferred-Credit $(8,002,460) per the FERC Form 1 does not agrees with the filing RR-2.10 which reflects $(8,501,412), a variance of $498,952. The SAP general ledger agrees with the filing. The Company indicated that the variance was “*due to the reversal of an entry to correct an unsettled WBS charge impacting regulatory net income.*” **Audit Issue #1 and Audit Issue #28**

The amount represents a 31% decrease over the 12/31/2021 FERC Form 1 balance. Eleven SAP general ledger accounts make up the year-end balance of $(8,501,411.50):

50000010922000	Salaries and Wages	$ (283,886.41)
50400010922000	AllocCorp Cap Leg	$ 1,727.87
50500010922000	Other Operating Exp	$ -
50510010922000	Cost Alloc to Cap	$ (8,053,384.33)
80000010922000	Lbr Alloc	$ 2,373.00
80300010922000	Assess Lbr	$ (109,749.16)
80302010922000	Assess Material	$ 375.78
80304010922000	Assess Other	$ (64,327.20)
80305010922000	Assess Fleet - Asses	$ 22.02
80308010922000	Assess Meals	$ 532.59
80308510922000	Assess Travel	$ 4,904.34
		$ (8,501,411.50)

Please see the _Payroll_ and _Allocation_ sections of this report for a detail review of payroll and allocated labor.

Account #923 Outside Services Employed $2,381,415 per the FERC Form 1 reflects a decrease of 22% from the 12/31/21 year. The FERC Form 1 balance agree to filing schedule RR-2 and to the following SAP general ledger accounts:

50000010923000	Salaries and Wages	$ 8,439.80
50030010923000	Outside Svs	$ (171,988.65)
50034010923000	AllocCorp OutSvs Leg	$ 525,272.94
50240010923000	Legal Expenses	$ 27,132.20
50252010923000	Prof Svs-Acct/Audit	$ (25,583.57)
50254010923000	Prof Svs-Other	$ 488,549.77
50500010923000	Other Operating Exp	$ 11,593.84
50520010923000	AllocCorp NonLbr Leg	$ 784,967.28
50521010923000	AllocReg NonLbr Leg	$ 648,862.73
80000010923000	Lbr Alloc	$ 183.15
80303010923000	Assess Services	$ 1,397.03
85303010923000	As Serv-Intrc	$ 82,588.38
		$ 2,381,414.90

Although the FERC Form 1 amount agrees to the filing and the ending SAP general ledger balance, there was a $4,133.98 difference between the ending GP general ledger balance as of 9/30/22 and the SAP starting balance as of 9/30/22. **Audit Issue #1** The difference was related to a mapping issue where former GP account 8830-2-9825-69-5200-9230 was mapped to SAP account 50254010999999 instead of one of the 923 SAP accounts listed above.

Audit reviewed the GP general ledger and noted the following in accounts 8830-2-XXXX-69-5200-9230 Outside Services, which had a total of 17 accounts summing to $2,213,497.99 as of 9/30/22:

Outside Services Other - Account 9230 $340,835.44

8830-2-9800-69-5200-9230	$ 28,620.54
8830-2-9810-69-5200-9230	$ 30,139.79
8830-2-9812-69-5200-9230	$ 553.15
8830-2-9815-69-5200-9230	$ 21,140.23
8830-2-9820-69-5200-9230	$ 137,951.24
8830-2-9823-69-5200-9230	$ 56,546.46
8830-2-9830-69-5200-9230	$ 8,950.00
8830-2-9850-69-5200-9230	$ 3,401.53
8830-2-9854-69-5200-9230	$ 53,532.50
Subtotal of Accounts 9230	$ 340,835.44

Entries included monthly non labor accruals and reversals, tax and audit fee accruals. Amortization of prepaid expenses, legal fees and legal accruals. There were 106 invoices from vendors in this subaccount. Audit requested information for the 2 highest invoices from this subaccount totaling $42,500 from CMG Consulting, LLC and Pastori Krans PLLC totaling $17,637.70. The invoice from CMG Consulting LLC was the last payment toward the Liberty Utilities Grid Modification plan for the Bellow Falls area. The invoice was dated 2/18/22 and noted that there was "Delivery of final NWS reports and no travel or incidental charges" were on the invoice. The invoice from Pastori Krans was legal fees associated with case Liberty vs. Clearway Industries. The invoice was for 65.80 hours' worth of time and small copies fees for the month of Mach 2022.

Administrative Allocations Accounts 9211, 9232, 9234, 9235, 9236, 9237, 9238

8830-2-0000-69-5200-9231	Outside services LU HO Allocations	$ 29,522.15
8830-2-0000-69-5200-9232	Outside services APUC HO Allocations	$ 409,780.78
8830-2-0000-69-5200-9234	LABS NonLabour Allocations	$ 174,917.82
8830-2-0000-69-5200-9235	LABS Corporate Service non-labour allocation	$ 386,901.89
8830-2-0000-69-5200-9236	LABS US Bus admin alloc	$ 72,782.48
8830-2-0000-69-5200-9237	LABS US Corp admin alloc	$ 148,361.45
8830-2-9821-69-5200-9237	LABS US Corp Admin Allocations	$ 2,003.64
8830-2-0000-69-5200-9238	LU Corp US Admin alloc	$ 181,598.01
		$ 1,405,868.22

All accounts included monthly indirect allocations and reversals. Please see the *Allocation* section of this report for additional information on corporate allocations.

East Region Outside Services Account 9239 $466,794.33

8830-2-0000-69-5200-9239	$ 443,656.40
8830-2-9810-69-5200-9239	$ 16,727.32
8830-2-9820-69-5200-9239	$ 14.37
8830-2-9865-69-5200-9239	$ 6,396.24
	$ 466,794.33

Account 8830-2-0000-69-5200-9239 (LU Region Admin Allocation) included indirect allocations and reversals. See the *Allocation* section of this report for a review of corporate allocations. There was only 1 invoice posted to account 8830-2-9865-69-5200-9239 (East Region Outside Services - Customer Service) totaling $97.11 for the Better Business Bureau of New Hampshire.

Audit also reviewed the SAP general ledger and notes the following in relation to the coding system identified in Account 921. There were 102 carry forward transactions summing to $2,218,800.40 however there were 3 transactions dated after the transition date of 9/30/22 totaling ($3,469.03) and dated 10/31/21. The Company clarified that the "*$(3,469.03) of CF charges dated 10/31/2022 were the reversals of accruals booked on 9/30/2022 in the Great Plains system which needed to be reversed manually in SAP in October. SAP automatically processes reversing entries on the first day of the following month, identical to the process in GP, however this process could not be done in SAP in October since the originating entry was posted in GP, not in SAP. These transactions would not have caused a variance between the GP general ledger and the SAP general ledger"* (at year-end). The carry forward charges 1/1/22 – 9/30/22 total $2,222,269.43 and as noted earlier differ than the ending GP balance of 2,213,497.99.

Entries designated with "CO" or "CO Posting" consisted of 681 entries totaling $83,985.41 and included memos for intercompany capital, investor relations, environmental compliance, talent acquisition, procurement services, insurance and HR services. Invoices with the "KR" designation for vendor invoices totaled $128,131.02 with some invoices designated as facilities, procurement, finance, "Government Affairs" and legal. Audit requested information for the 2 highest invoices totaling $31,448.75 and $19,446.45 only identified as "Regulatory". The Company provided the 2 invoices from Guidehouse summing to $50,895.20 for surveying and evaluation reports. The Company indicated both invoices were "*transferred to Battery Storage deferral account*" and therefore should be excluded from expense account 923. **Audit Issue #22**

There were 54 entries totaling ($125,190.96) designated as "SA" or "G/L Account Document" and included time sheet conversions, tax and audit fee accruals and reversals, and reclassifications. Only 1 entry was coded to "WE" or Goods Receipt for $600 and was further identified as "Rates & Regulatory-Outside Services". Additionally, there was only 1 entry coded to "WF" or WFS Integration summing to $183.15 and identified as "Electric Meter Srvs-Outside Services-Sal".

There were 5 entries coded to "ZA" or "Accrual Document" that totaled $74,305.88 and were all dated 12/31/2022. The entries were further identified as E&Y Audit Accrual, AP accrual and legal accrual.

Account #924 Property Insurance $1,589,317 per the FERC Form 1 demonstrates an increase of 1% over the prior year. The filing schedule RR-2.10 agrees with the FERC Form 1 which was verified to the SAP year-end balances reflected in the schedule.

50101010924000	Property Insurance	$1,589,024
85311410924000	As Prop Ins-Intrc	$ 293
		$1,589,317

General ledger detail also shows account 80111410924000 totaling $5,337. These entries were mapped incorrectly and reclassified to FERC account 242.

Schedule RR-2.10 reflects $1,500,000 pro forma adjustment. The $1,500,000 amount, per the general ledger, is debited $125,000 monthly, and is a source of funding for the major storms through credits to account 24140010254000, Other Regulatory Liabilities. The liability account is discussed in detail in the Utility's Storm Fund audit reports. The 2022 Storm Cost audit report, in docket DE 23-035, was issued on August 17, 2023.

Account #925 Injuries and Damages $927,599 per the FERC Form 1 reflects an increase over the prior period expense total $800,546, or 16%. The filing schedule RR-2.10 agrees with the FERC Form 1 balance. Schedule RR-3.9 shows the policies running from mid-2021 through mid-2022 total $1,052,198. The Schedule also shows the policies running from mid-2022 through mid-2023 sum to $919,284.

50030010925000	Outside Svs	$	1,500.00
50105010925000	Inj & Damages Insrce	$	926,099.02
		$	927,599.02

Two additional 925 accounts, totaling $8,263.31 are included in the general ledger but not the FERC Form 1.

50500010925000	Other Operating Expense	$ 0
80111810925000	OH Injuries & Damage	$8,263

The three entries in the Other Operating Expense account were reclassifications to the correct regulatory account, netting to zero. The OH Injuries & Damage total of $8,263 was mapped incorrectly and was reclassified to account 242. **Audit Issue #1**

Expenses in the Injury & Damages account included monthly amortization of prepayments and a payment to AEGIS.

Account #926 Employee Pensions and Benefits $3,697,502 per the FERC Form 1 is a reduction from the prior period of 22%. The account balances within the filing schedule RR-2.10 sum to $4,053,502, or $356,000 higher than the FERC Form 1. The general ledger shows a total of $3,720,678, or $23,176 higher than the FERC From 1. In response to a request for clarification of the variances, the Company noted that the variance "*is due to a correction for pre-cap meter overheads which were double booked.*" (see also $498,952 variance in account 922). The Company further noted that *The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement."* Audit informed the Department of Energy staff to this and Data Request #11-14 was issued on October 5, 2023. Refer to **Audit Issue #1 and Audit Issue #28**

Extensive data requests were issued and answered regarding the pensions and benefits.

17010010926000	LTRA Pen&PostEmp Ben	$ -
50014010926000	Opt Out Cr	$ 6,963.19
50015010926000	Medicare/Healthcare	$ 1,499,628.24
50016010926000	RRSP/DPSP/401K	$ 1,287,679.75
50017010926000	Group/Emp Ben	$ (299,212.27)
50023010926000	StkPurPlns Emp Cntr	$ 20,423.82
50027010926000	Car Allowance	$ 249.23
57801010926000	OPEB Non-Srv Cst	$ 847,595.00
57802010926000	Pension Nn-Srv Costs	$ 198,075.04
70211010926000	BS Ops OH Benefit	$ (180,350.62)
70211710926000	BS OH PenOPEB Nonser	$ 86,197.16
80111010926000	OH Benefits	$ 17,353.50
80111310926000	OH Pension/OPEB	$ 5,823.05
85311010926000	As OH BenIntrc	$ 229,617.97
85311310926000	As Pnsn/OPEB-Intrc	$ 635.39
		$ 3,720,678.45

Please see the *Payroll* and *Allocation* sections of this report for additional information.

Account #928 Regulatory Commission Expenses $643,455 per FERC Form 1 is an increase over the 2021 balance of 18%. The general ledger account activity for January through September 2022 was noted in account 8830-2-9830-69-5610-9280, Regulatory Commission Expense. At conversion, the activity was rolled into SAP account 3071-50506010928000 Reg Commissions Exp.

Audit reviewed the PUC fiscal year assessments for 2022 (July 2021 through June 2022) and 2023 (July 2022 through June 2023):

	Electric	IESR	
2022 Quarter 3	$136,877	$ 41,366	
2022 Quarter 4	$136,877	$ 41,366	
2023 Quarter 1	$ 99,723	$ 28,916	
2023 Quarter 2	$128,820	$ 37,709	
	$502,297	$149,357	$651,654 combined

The IESR is the imputed energy suppliers' revenue. The $651,654 is reflective of the net assessments paid after a credit for overcollection from the prior year is applied in Quarter 1.

Audit reviewed the account activity in both the Great Plains system and the SAP. Monthly accruals were noted. The difference between the amount noted on the FERC Form 1 and the assessment amount is $8,199. Audit verified the difference to two specific journal entries:

February 28, 2022	$ 1,800.00
WBS element 1016710599(Strategy Svc)	
December 31, 2022 reclass PUC Assess to Default Srv	$(10,000.00)

The entries were offset to the following accounts:

10928000 Regulatory Commission Expenses	$1,800	
8830-2-9868-69-7450-4264 Political Contributions	$ 600	
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$1,800
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$ 600

The $1,800 membership investment, strategic plan, was part of a total Business and Industry Association (BIA) membership fee of $2,400 and appeared to have been incorrectly posted to the Regulatory account. In response to the draft audit report, the Company clarified that "*the total Business & Industry Association New Hampshire (BIA) membership dues were $8,000, and the table below provides Granite State Electric's share of the costs. The lobbying portion of the dues ($600) was correctly charged to political contributions. The $1,800 membership dues portion was incorrectly charged to regulatory commission expenses and should have been charged to dues and membership. The Company will make this adjustment in the next update of the revenue requirement model in this proceeding*." **AUDIT ISSUE #23**

	Total	GSE	EN
Dues	$ 6,000	$ 1,800	$ 4,200
Lobbying 25%	$ 2,000	$ 600	$ 1,400
Total Dues	$ 8,000	$ 2,400	$ 5,600

10142001 (Cust A/R- Undr Collect-Default-O/U)	$10,000	
10928000 (Regulatory Commission Expenses)		$10,000

The Revenue Requirement schedule RR-3.7, however, reflects:

DOE Assessment	$628,226
Recovered through Energy Service Rate	$ (10,000)
Total DOE Assessment in Distribution Base Rates	$618,226

Audit notes that a variance between the payments reflected in the FERC Form 1 and in the general ledger are a combination of 2 quarters from 2 different fiscal years (or calendar year) as opposed to the amount listed in Revenue Requirement schedule RR - 3.7 which is reflective of one full fiscal year 2024 (July 2023 through June 2024).

	Electric	IESR
2023 Quarter 1	$50,482	$ 28,916
2023 Quarter 2	$136,877	$ 37,709
2024 Quarter 3	$ 99,723	$ 37,709
2024 Quarter 4	$128,820	$ 37,709
	$502,297	$150,834

<u>Account #930.2 Miscellaneous General Expenses $(115,412)</u> per the FERC Form 1 reflects a reduction from the prior year $61,330 expense total. Audit verified the total to the filing Schedule RR-2-10.

The general ledger activity January through September was noted in Great Plains account

8830-2-0000-69-5615-9302 Miscellaneous General Expenses	$ 477.75
8830-2-9810-69-5615-9302 Miscellaneous General Expenses	$ 952.87
8830-2-9815-69-5615-9302 Miscellaneous General Expenses	$ 1,030.48
8830-2-9825-69-5615-9302 Miscellaneous General Expenses	$ 96,329.65
8830-2-9851-69-5615-9302 Miscellaneous General Expenses	$ 852.56
8830-2-9853-69-5615-9302 Miscellaneous General Expenses	$ 1,806.52
8830-2-9860-69-5615-9302 Miscellaneous General Expenses	$ 214.00
8830-2-9860-69-5615-9302 Miscellaneous General Expenses	$ 8,996.70
Account 930.2 Miscellaneous General Expenses a/o 9/30/2022	$110,660.53

The total of the Great Plains 930.2 accounts at 9/30/2022 was incorporated into the SAP Other Operating Exp account 3071-50500010930200. At year-end 12/2022, there were 3 SAP accounts for Miscellaneous General Expenses:

3071-50030010930200 Outside Services	$ 4,040.00
3071-50500010930200 Other Operating Exp	$(119,825.51)
3071-80000010930200 Lbr Alloc	$ 373.14
Account 930.2 a/o 12/31/2022	$(115,412.37)

Audit reviewed the activity in account 8830-2-9825-69-5615-9302 and noted 30 journal entries. All entries indicated a description of Job 8830-9825-COVID19. Nine of the entries related to Enterprise Holdings, Inc. d/b/a EAN Services and Enterprise Rent A Car. The sum of the car rentals is $89,975.21. Audit requested clarification of the job and a listing of the employees to whom the rentals were assigned. Audit further requested all jobs and related accounts associated with job 8830-xxxx-COVID19. The Company noted the following:

> "*The vehicles were rented for general use by field employees who typically worked as a team in one vehicle, thus allowing safe work conditions. The vehicles were not assigned to any one employee and consisted of a variety of vehicle types including pickup trucks, SUVs and passenger vehicles. The selected invoices covered vehicle rental periods from 11/19/2021 through 5/2/2022. The jobs established to track costs related to COVID-19 were charged to account 930.2 with labor for one job charged to account 920. The total costs by job and account are shown below:*"

COVID Job	Total Charges	GP GL Account	Total Charges
8830-9810-COVID19	$ 3,503.66	8830-2-9810-69-5615-9302	$ 3,503.66
8830-9815-COVID19	$ 59,013.76	8830-2-9815-69-5615-9302	$ 59,013.76
8830-9825-COVID19	$ 156,245.46	8830-2-9825-69-5615-9302	$ 156,245.46
8830-9830-COVID19	$ 77.70	8830-2-9830-69-5615-9302	$ 77.70
8830-9835-COVID19	$ 2,030.75	8830-2-9835-69-5615-9302	$ 2,030.75
8830-9840-COVID19	$ 25.91	8830-2-9840-69-5615-9302	$ 25.91
8830-9853-COVID19	$ 13,225.78	8830-2-9853-69-5615-9302	$ 13,225.78
8830-9860-COVID19	$ 214.00	8830-2-9860-69-5615-9302	$ 214.00
8830-9865-COVID19	$ 13,323.06	8830-2-9865-69-5615-9302	$ 13,323.06
8830-9851-COVID19	$ 156,749.46	8830-2-9851-69-5010-9200	$ 34,201.82
		8830-2-9851-69-5615-9302	$ 17,923.18
		8830-2-9852-69-5615-9302	$ 104,624.46
Grand Total	$ 404,409.54	Grand Total	$ 404,409.54

Because the COVID-19 pandemic has subsided, Audit recommends that all of these charges be considered non-recurring, and some, according to the Company information, are outside of the test year, although they did not indicate specifically which ones. **Audit Issue #18**

Among the activity in the SAP 3071-50500010930200, which resulted in the $(119,825.51) balance, were several corrections and reclassifications. Specifically:

9 entries-GSE missed A&G assessment correction 12.2022	$(93,907.22)
2 entries -Dec LUSC RCL	$(161,748.71)
9 entries - NH Interest Correction	$(12,816.72)
4 entries -Reclass to correct Reg Acct	$ net to -0-

The offset to the $(93,907.22) and $(161,748.71) were identified by the Company to be debit to Construction Work in Progress account 50500010107000. The $(12,816.72) was debited to Intercompany Payable, account 20101010234000.

Account #931 Rents $205,469 per the FERC Form 1 shows an increase from the prior year of 7%. The total on the FERC Form 1 was comprised of the Great Plains system balances as of 9/30/2022, incorporated into the year-end balances in SAP:

8830-2-0000-69-6125-9310	Rental Expense – Intercompany	$132,786.40
8830-2-9823-69-5110-9310	Rent Expense	$ 7,552.75
8830-2-9830-69-5110-9310	Rent Expense	$ 9,382.58
8830-2-9840-69-5110-9310	Rent Expense	$ 1,985.54
Rent Expense as of 9/30/2022		$151,707.27

The Rental Expense-Intercompany account, was rolled into SAP 3071-50130010931000. The remaining three Great Plains accounts, summing to $18,920.87, were rolled into SAP account 3071-50300010931000. At year-end, the SAP accounts were:

3071-50130010931000 **Meals & Ent**	$132,786.40	RR-2.10
3071-50300010931000 Rental Expense	$ 71,284.90	RR-2.10, RR-3.8
3071-50304010931000 Lease Exp	$ 1,397.50	RR-2.10
3071-50500010931000 Other Operating Exp	$ -0-	
Rent Expense at year-end 12/31/2022	**$205,468.80**	**agrees with FERC Form 1**

The Rental Expense $71,284.90 was noted on the Revenue requirement schedule RR-3.8 as:

Intercompany Rental Expense Granite State annual lease	$59,236	Londonderry Office
Other Rental Expense	$12,049	
	$71,285	

The Intercompany account, $132,786.40 represents GSE's portion of the Londonderry office rent and the Concord Training Center. Audit noted monthly payments of $4,936.00 in GP and SAP each representing the GSE portion of the Londonderry office lease. For the year, the total was $59,236. Concord Training Center monthly lease payments were $10,560.95 for January through April 2022 and were $10,206.12 during the months of May through December 2022. Lease/rental payments are allocated between Granite State Electric and EnergyNorth.

Liberty and Ciborowski Associates, LLC have lease agreements for 2 properties: 2,150 square feet at 116 North Main Street, Concord (through 11/30/2026); and 1,660 square feet at 114 North Main Street, Concord, amended in 2019 to include an additional 645 square feet at 114 North Main Street. The lease at 114 North Main Street was extended until 11/30/2026, but the portion of the lease relating to the 645 square feet was not extended, and thus expired 11/30/2021. The amended leases were executed 12/30/2021. Express combined monthly rental was noted to be:

Per Amended Lease Agreement		Audit calculated	
Lease Period	Rent	Calendar Year	
12/1/2021 through 11/30/2022	$13,550.00 per month	$163,006.50	2022
12/1/2022 through 11/30/2023	$13,956.50 per month	$167,896.70	2023
12/1/2023 through 11/30/2024	$14,375.20 per month	$172,933.65	2024
12/1/2024 through 11/30/2025	$14,806.45 per month	$30,057.09	2025
12/1/2025 through 11/30/2026	$15,250.64 per month	n/a	

Lease/rental payments are allocated between Granite State Electric and EnergyNorth.

In response to DOE Staff Data Request #4-48, Liberty indicated that the original filing schedule RR-3.8 did not include all of the Rental Expenses. That response showed that RR-3.8 should have reflected:

Intercompany Rental-Londonderry building annual lease	$ 59,236
Intercompany Rental-Concord Training Center annual lease	$123,893
Facility Lease E-Point for 130 Main St. Salem	$ 26,125
Facility Lease 116 N Main St. Concord	$ 854
Filing per DOE DR 4-48	**$210,108**

The response reflects a change from the original RR-2.10 **$ 4,639 The DR 4-48 does not agree with the FERC Form 1. Audit Issue #24**

Account 935, Maintenance of General Plant $7,320

The FERC Form 1 reflects a total of $7,320 while the SAP general ledger as reflected on the filing schedule RR-2.10 shows a total of $7,322.16. The $2 variance is due to rounding and was not reviewed further. At the end of calendar year 2021, there was $-0- expense noted for account 935.

Audit reviewed the 2022 activity, and noted monthly entries supporting specific facilities in Charlestown, Lebanon, Londonderry, and Salem. Timesheet conversions and p-card expenses comprised the total. By location, Audit noted maintenance expenses for:

Charlestown	$ 175.00
Lebanon	$ 676.29
Londonderry	$6,270.91
Salem	$ 199.96
Total	$7,322.16

Due to time constraints, Audit was unable to test the $6,270.91maintenance total to determine if any part of that sum should have been allocated to EnergyNorth.

Corporate Allocations

Corporate expenses are allocated to GSE either directly or indirectly on a monthly basis. Audit requested all corporate billings for the month of November. GSE provided Audit with the following billings and supporting documentation:

- Direct Billing Manual LUC
- Direct Billing Manual LABS
- Direct Billing Auto-settle LUC/LABS combined
- Direct Billing Manual LUSC
- Direct Billing Auto-settle LUSC
- Indirect Billing Auto-settle LUSC combined
- Indirect Billing Auto-settle LUC combined
- Indirect Billing Auto-settle LABS combined

Direct Billing Manual LUC

Liberty Utilities Canada issued an invoice to GSE on 11/25/22 for the November 22 Direct Billing in the amount of $2,380. An Excel spreadsheet was provided to Audit as support for the invoiced amount. The spreadsheet contained expenses from Company Code 1048 and noted the customer as 2100EAST, 2100ENORTH and 2100GSTATES. Each line item noted if it was labor, outside services (with vendor names), benefits, etc. As LUC is a Canadian company, the invoices amounts are in Canadian Dollar with a conversion to USD.

The $2,380 charged booked to GSE was noted to be outside services for Granite State Regulatory Rate Case. As the invoice was noted to be for GSE, there was no 70/30 split with ENG.

Direct Billing Manual LABS

Liberty Utilities Canada issued an invoice to GSE on 11/25/22 for the November 22 Direct Billing in the amount of $2,405. The same Excel spreadsheet was provided to support the November LABS billing as the LUC billing. The spreadsheet contained the detail noted above.

There are two entries, $191 and $2,214, that were charged to GSE. The spreadsheet notes they are for outside services for "EH&S for Granite State". As the expenses were for GSE only, they were not allocated 70/30 with ENG.

Direct Billing Auto-settle LUC/LABS combined

The direct billing auto-settle LUC/LABS totaled $126,646 for the month of November. As these charges are auto-settle, they are booked to GSE general ledger through an automated SAP settlement system. Due to this, there is no invoice provided to the Company.

Supporting documentation provided was an Excel spreadsheet containing a total of $1,237,88 in expenses from Company 1048. The spreadsheet contained several tabs including raw data, billing summary, pivot of the billing summary, a pivot for the NH changes and the procedures on processing direct billings.

Audit verified the raw data tab to the pivot billing tab. The pivot billing tab showed expenses of $126,645.55 for GSE. Audit then verified the GSE total to the NH Pivot without exception. The NH pivot provided the GL account, noted if it was outside service, labor, benefits, etc. Vendor names were also included for outside services. These expenses were booked fully to GSE's general ledger.

Expenses charged to GSE were for outside services, labor allocations, overhead benefits, and overhead bonuses.

The pivot billing tab noted a total of $331,014 of expenses for Liberty NH. These charges were booked 30% to GSE and 70% to ENG.

Direct Billing Manual LUSC

Liberty Utilities Central Shared Services Co. provided an invoice to GSE on 11/25/2022 for November charges. The invoice totaled $46,227.55. GSE provided an Excel spreadsheet containing the billing data and a GSE billing summary.

The billing data showed the expenses booked to Company 3060 totaling $2,027,654. The data noted for which company the expense was, the type of expense, the Canadian Dollar amount and the USD amount, and other information. Audit verified the GSE total of $46,227 to the billing data.

The GSE billing summary tab provided a pivot table showing the GSE company, GL account number, type of expense and the total. The billing data also showed $61,588 being charged to Liberty NH in which the amount would be allocated 70/30.

Expenses charged to GSE were for travel expenses, meals & entertainment, labor allocations, and overhead expenses.

Direct Billing Auto-settle LUSC

The direct billing auto-settle for LUSC does not have an invoice. As previously noted, auto-settlement automatically books the expense to the GL through the SAP settlement system.

The total billed to GSE was $49,441. The supporting Excel spreadsheet provided the same type of information as noted in the Auto-settle direct billing for LUC/LUSC combined.

Audit verified the raw data, to the billing pivot, to the NH billing summary to the NH pivot without exception. $2,632 of the total was for travel expense, meal & entertainment, miscellaneous deductions, seminars, tips, hotels associated with energy efficiency programs. The remaining expenses were for travel, meals & entertainment, fleet, overhead, other operating expenses and the majority being for labor.

The 3070 total was $(694,068) for labor allocation and labor offset. This total was allocated 30% to GSE and 70% to ENG.

Indirect Billing Auto-settle LUSC combined

The expenses billed to GSE through the auto-settle LUSC are allocated through the 4 factor percentage. The percent charged to GSE is noted in the very beginning of the audit report. A total of $221,466 was allocated to GSE for November. Expenses included labor and associated costs, property insurance, travel, fleet, materials, services, and other.

As these expenses are auto-settled not invoice was provided. Supporting documentation included an Excel spreadsheet which contained the SAP billing data, and several tabs breaking the data down into different regions which checks and balances.

The East Region tab shows $127,387 being allocated to GSE at 4.30%. The Libcorp tab shows a GSE total of $38,422 at 4.40%and LABS tab shows a total of $55,657 at 4.40%. The total of these three tabs is $221,466

The GSE summary tab totals all the expenses charged to GSE and the GSE summary pivot provides the detail total by account number .

Indirect Billing Auto-settle LUC combined

The expenses billed to GSE for the LUC Indirect billing total $98,603. Supporting documentation provided included an Excel spreadsheet with the GL details, LU allocations, GSE summary and GSE summary pivot among other detail.

These LU expenses are allocated to GSE using the 4 Factor Percentage of 4.4%. The GSE Summary tab ties to the GSE summary pivot showing $98,603 charged to GSE for labor, materials, fleet, meals, payroll taxes and overhead benefits.

Indirect Billing Auto-settle LABS combined

The billed to GSE for the auto-settle LABS billing totaled $81,699 for November 2022. As supporting documentation to the auto-settle charges, GSE Provided an Excel spreadsheet. The spreadsheet provides the SAP detail, SAP journal entry, LABS allocation, GSE Summary and GSE Pivot.

Through the supporting Excel spreadsheets provided, Audit was unable to verify any of the corporate billing charges to the GL. Audit was also unable to verify the amounts being charged to GSE were based on the 4 Factor Percentage. **Audit Issue #25**

Taxes - Federal Income Tax

On January 1, 2014, a Tax Sharing Agreement went into effect, executed by the Vice President of Finance (of Algonquin). The Company indicated the agreement has not changed. The agreement represents that the consolidated returns will be compiled, with the members providing to the Parent the equivalent tax payment as if the member had filed individually. The agreement Schedule A reflected a listing of 32 original members, of which Liberty Utilities (Granite State Electric) Corp was one. Each has a specific Employer Identification Number.

Audit requested copies the federal tax returns filed by Liberty Utilities (America) Co for the test year. Pro forma federal form 1120 tax returns for Granite State were provided for 2021. The federal tax return detail was provided on July 10, 2023. The 2021 Federal return was filed on October 17, 2022 by KPMG. The Company anticipates filing the 2022 Federal Income Tax return by mid-October 2023. The overall taxable income was a loss for Liberty Utilities (America) Co and Subs with an overpayment for $4,759,101 identified. The overpayment was credited to the 2022 estimated tax. The consolidated schedule 1120 page 1, statement 3 reflects the GSE portion as a taxable net income of $15,597,304 based on:

Gross sales	$ 107,899,134	agrees with general ledger and FERC
Cost of goods sold	$ (61,336,383)	
Interest Dividend Income	$ 482,430	agrees with general ledger and FERC
Gross Royalties	$ 99,482	
Other Income	$ 1,858,934	
Salaries and Wages	$ (12,409,961)	
Bad Debts	$ (299,852)	
Repairs and Maintenance	$ (5,010,654)	
Rents	$ (188,872)	
Taxes and Licenses	$ (5,583,305)	
Interest	$ (2,204,756)	
Depreciation	$ (10,348,073)	
Charitable Contributions	$ (8,570)	
Advertising	$ (252)	
Other Deductions	$ (2,647,992)	
Taxable Income	$ 15,597,304	

The overall net income per the general ledger and FERC for 2021 was $12,529,618.

Schedule M2, statement 145 reflects the following:

Balance at beginning of year	$ 21,053,843
Net income per books	$ 12,420,797
Balance at end of year	$33,474,640 unappropriated retained earnings per proforma

20021 GSE 1120 return.

Schedule L, statement 75 Beginning, and schedule 82 Ending balances, of the 2021 federal return summarized GSE:

	Beginning	Ending
Cash	$ 61,625	$ (2,074)
Trade Notes and A/R	$ 15,822,178	$ 18,097,418
Less Allowance for Bad Debt	$ (752,497)	$ (734,292)
Inventories	$ 2,538,074	$ 2,400,315
Other Current Assets (1)	$ 11,938,777	$ 11,297,024
Bldgs and Other Depreciable Assets	$233,773,511	$265,551,731
Less Accumulated Depreciation	$(41,980,892)	$(49,641,737)
Land	$ 1,500,000	$ $1,500,000
Less: Intangible Asset A/D	$ (1,596,554)	$ (1,666,669)
Other Assets	$ 7,498,514	$ 9,834,430
Total Assets	$231,995,844	$259,969,484
Accounts Payable	$ 19,647,297	$ 30,553,030
Other Current Liabilities (2)	$ 15,118,960	$ 24,009,258
Mtg, Bonds, Notes Payable >1yr	$ 31,977,817	$ 31,981,581
Other Liabilities	$ 48,644,470	$ 42,128,039
Common Stock	$ 82,024,903	$ 82,024,903
Additional Paid in Capital	$ 17,000,000	$ 17,000,000
Retained Earnings	$ (21,053,843)	$(33,474,640)
Adjustment to Shareholder Equity	$ (3,471,446)	$ (1,201,967)
Total Liabilities and Equity	$231,995,844	$259,969,484

(1) Other Current Assets were noted on statement 97 to include:

Prepaids	$ 1,401,770	$ 1,233,254
Current Regulatory Assets	$10,537,007	$11,011,159
Income Tax Receivable	0	($947,389)
Sub-total	$ 11,938,777	$11,297,024

(2) Other Current Liabilities were noted on statement 118 to include:

Accrued Liabilities	$ 9,803,286	$10,957,868
Current Portion of Other LTD	$ 1,181,318	$ 1,206,777
Current Portion Regulatory Liab	$ 3,995,431	$ 4,883,774
Accrued Interest	$ 325,292	$ 142,792
Current Tax Payable	$ (186,367)	$ 2,091,481
Other Current Liabilities	$ 0	$ 4,775,983
Operating Lease Liability	$ 0	$ 583
Sub-total	$15,118,960	$ 24,009,258

Audit verified that the reported GSE portions of the Liberty Utilities (America) Co federal tax return agrees with the pro-forma GSE stand-alone federal tax return. Certain items were verified to the general ledger of GSE, without exception.

The Company provided a copy of the Liberty Utilities (America) Co. & Subs statewide tax returns for the calendar year 2021. The 942-page document, prepared by KPMG, LLP Toronto, included state specific returns for Arizona, Arkansas, California, Georgia, Illinois, Iowa, Kansas, Massachusetts, Missouri, New Hampshire, New York, Oklahoma, and Texas. For Liberty Utilities (America) Co, the NH BT-Summary reflected a net overpayment for the tax year 12/2021 of $107,290 that was filed on November 15, 2012. The Company has not filed its 2022 NH BT-Summary and anticipates filing the return by Mid November 2023.

State Income Taxes

The 2021 Liberty Utilities (America) Co. & Subs information was provided on July 10, 2023. The BET was overpaid by $107,290, with the overpayment applied to the 2022-estimated tax. The overpayment was the result of:

The calculated BET	$ 358,597
Less estimated tax payments	$(230,000)
Less Tax Paid w/ Application Extension	$ (190,000)
Less carryover from prior tax period	$ (45,887)
Net overpayment	$(107,290)

The NH Business Profits Tax Return indicated that there is a net operating loss deduction (NOLD) to be carried forward in the amount of ($13,904,514), at the Liberty Utilities (America) Co level. Use of a portion of the NOLD resulted in a loss for the year. The net income noted on statement 3, $12,420,797 agrees with the federal return. Statement 11 reflects 29 other members included in the water's edge combined group.

General Ledger Accounts Associated with State and Federal Income Taxes

The Company has not filed 2022 State or Federal Income Taxes but provided Audit with the proformed tax worksheets and provisional tax entries compiled by the Tax Manager in Oakville.

The Accumulated Deferred Income Taxes account 190 did not have any activity during 2022 and had a zero balance, which agrees with the FERC Form 1.

The Accumulated Deferred Income Taxes-Other account 283 on the FERC Form 1 consisted of five accounts with three accounts not having any account activity and ended 2022 with a zero balance. The LTL Accumulated Deferred State Income Tax Account Utility Property Plant and Equipment ended 2022 with a $0.02 account balance.

17090010283000 LTRA Income Tax	$0
24090010283000 CPRL Income Taxes	$0
26090010283000 LTRL Income Taxes	$0
27200010283000 LTL Accum Def. Fed. Income Tax PPE	($17,743,668)
27210010283000 LTL Accum Def. State Income Tax PPE	$0.02
Total 283 Per Annual Report	($17,743,668)
24090010254000 CPRL Income Taxes	($268,243)
26090010254000 LTRL Income Taxes	($4,763,022)
Total 283 and 254 accounts Per GL	($22,774,932
Filing Schedule RR-4.5 post close true up of state EADIT for rate case	($7,471)
Total ADIT Per filing schedule RR-4.5	($22,782,403)

Net GSE Accumulated Deferred Income Tax was verified to FERC Form 1 and the filing schedules RR-4.5. The Company summarized the purpose of the 283 and 254 accounts that "*includes both the excess deferred taxes as well as a tax gross-up related to the tax benefit of returning the excess ADIT to our customers through future rates. The gross-up represents future taxes and is offset by a deferred tax asset that has been recorded in the 283 account. The gross-up portion of the EADIT and the DTA net to zero on the balance sheet. For the rate case, we have excluded the gross-up from the EADIT balance and the corresponding deferred tax asset.*"

The 283 and 254 accounts on the GL summed to ($22,774,932) and the filing summed to ($22,782,403). This is a ($7,471) difference caused by a post close true up to state EADIT for the rate case and the related deferred tax asset.

Activity within the accounts was reviewed and verified to tax worksheets prepared by the Oakville Tax Manager. Offsetting entries were noted to Deferred State Income Tax Expense, Deferred Federal Income Tax Expense, and OCI FASB 158 Pensions account 36206010219000.

59001010409100 State Income Tax expense	$873,455	FERC Form 1 acct 409.1 line 16
59000010409100 Federal Income Tax Expense	$2,238,709	FERC Form1 acct 409.1 line 15
Total 409 accounts per GL	$3,112,164	
Total per Filing RR-2.13	$2,651,781	
Filing and 409 GL Variance	$460,383	

The 409 current income tax expense accounts summed to $3,112,164 while the filing schedule RR-2.13 totaled $2,651,781. This is a $460,383 difference that the Company indicated was properly excluded from the filing that were due to regulatory adjustments that were the result of a ($5,624) Business Enterprise Tax true up credit adjustment and a $466,007 NH Business Profits Tax rate adjustment.

The 409 federal and state income tax expense accounts Great Plains September 30, 2022 ending GL balance and the beginning balance for SAP were different from one another. The Company indicated the September 2022 SAP tax entries were booked to the incorrect account during the GP to SAP conversion which caused the identified differences below. The correcting entries were done in December and are summarized below.

As of September 30, 2022

8830-2-0000-80-8710-4090 Federal Income Tax expense per **GP**	$2,702,729
59000010409100 Federal Income Tax expense per **SAP**	$1,427,325
Federal 409 acct Difference	$1,275,404

December 2022 Correcting Entry

59000010409100	Federal Income Tax Expense	$1,275,404	
59000010920000	Administrative and General Salaries		$1,275,404

8830-2-0000-80-8720-4090 State Income Tax Expense per **GP**	$1,058,582
59001010409100 State Income Tax ExpensePer **SAP**	$559,042
State 409 acct Difference	$499,540

December 2022 Correcting Entry

59001010409100 State Income Tax Expense	$499,540	
59001010920000 Administrative and General Salaries		$499,540

5902101040100 Def FIT Expense	$1,250,385	ok to FERC Form 1 acct 410
59023010410300 Deferred Amort. Excess ADIT	($190,014)	
Total Per GL	$1,054,365	
Total Per Filing RR-2.13	$1,667,219	
Filing and GL difference	($612,855)	

The 410 deferred income tax expenses totaled $1,054,365 while the filing schedule RR-2.13 totaled $1,667,219. This ($612,385) difference is the result of operating income before tax adjustment differences between what was booked to the GL. For Regulatory purposes the operating before income tax adjustments were $16,763,546 for the test year and on the GL, it was $15,915,399. This is a ($848,147) difference. The Company provided the journal entries that were to capitalize the physical inventory write off, correct the over accrual of capital invoices that were paid in 2022, correct pre capitalized meter overheads that were double booked, and the reversal of an entry to correct the regulatory net income checklist item. Other differences include the Excess ADIT true up, AFUDC Amortization, State EADIT, and AFUDC Equity.

The 410 federal deferred income tax expense accounts Great Plains September 30, 2022 ending GL balance and the beginning balance for SAP were different from one another.

As of September 30, 2022

8830-2-0000-80-8760-4104 Deferred FIT per **GP**	$8,104
59021010410000 FDIT expense per **SAP**	$5,315
410 account Difference	$2,789

December 2022 correcting Entry

8830-2-0000-80-8760-4104 Deferred FIT	$2,789	
59001010920000 Administrative and General Salaries		$2,789

Prepaid Property Taxes

14081010165000 Prepaid Property Tax	$107,888
14090010165000 Other Prepaids	1,276,789
Total 165 Prepaids per SAP GL and FERC Form 1	$1,384,677
Prepayments RR-4 line 7	$1,915,251

The filing schedule RR-4 reflects total prepayments of $1,915,251 for 2022. The 165 prepaids account on the GL and FERC Form 1 summed to $1,384,677. This is a $530,574 difference that is a function of presentation/mapping of accounts. The 1402xx accounts are the three clearing accounts that will clear depending on timing. A specific example of this are payments made for purchase cards and expenses are matched against those as they are coded and approved through the purchase card system. A small rolling balance is expected based on the timing of when these payments are made. The $530,574 difference is made up of the following three GL accounts below.

140230 Billable Intercompany Clearing	$129,595
140240 Billable Clearing	$398,803
140250 Purchase Card Clearing	$2,176
Total	$530,574

Property Taxes

For the test year, the Company expensed $6,549,124. Refer to the filing schedule RR-2-11. Audit reviewed the second issue 2021 municipal property tax invoices for the 25 communities in which the Company has taxable assets, and both first and second issue invoices for 2022. Audit verified the reported expense and prepayment figures to the general ledger accounts below:

50011010408000 SS/CPP/Emp Pension	$457,573
50012010408000 Unemployment Insurance	$4,267
50013010408000 FICA Taxes	$237
50015010408000 Medicare Taxes	$125,786
80111210408000 Overhead Payroll Taxes	$4,620
85311210408000 As Payroll Tax-Intrc.	$28,632
50260010408000 Property Tax RR-3.6	$5,906,188
80111210408000 Overhead Payroll Taxes	$26,441
Total per filing schedule RR-2.11 and FERC Form 1	$6,549,124

80111210408000 Overhead Payroll Taxes	$4,620

See the *payroll section* of this report for a more detailed explanation for variances related to payroll/payroll taxes.

Audit requested and was provided with all municipal property tax invoices for the years 2021 and 2022, as well as the State of New Hampshire utility property tax invoices. The result of that review is demonstrated below, per Audit calculation that was done by multiplying the town mill rate by property valuation on the town property tax invoice:

½ of 2021 second issue municipal	$1,006,248	
Complete 2022 first issue municipal	$2,091,070	
½ of 2022 second issue municipal	$ 1,395,987	
Subtotal municipal	$4,668,924	
2022 State of NH Utility Property tax	$1,288,617	
Total property tax calculated expense	$5,781,922	$124,266 lower than GSE expensed on GL

The calculated property tax expense for the year is $124,266 lower than the $5,906,188 amount booked to the general ledger 408 property tax expense account. The reason for the $124,266 difference that Audit calculated, and the GL is due to timing differences and true up of municipal/state property tax expenses. The Company on filing schedule RR-3.6 calculated the property tax expense for 2022 to be $6,171,661 while the GL 408 account expensed amount is $5,906,188. The reason for the $265,473 difference in property tax bills vs. expense has to do with the difference between fiscal and calendar year property tax bills. The Company specially indicated, "*Towns that operate on a fiscal tax year will have bills paid in a different calendar year than 2022. (ex. Bill received in December 2021 would be for the period January–June 2022). For each of the following 6 months after the bill was received, 1/6 of that amount is moved from the 165 Prepaid Expense amount to the 408 Property tax expense account. The same process will occur for fiscal towns for the months of July–December for bills received in June. Bills received for fiscal towns in December 2022 would be related to expenses for the first 6 months of 2023, even though they were paid in 2023. Therefore, the $265,473 difference is related to property tax bills that will be expensed in 2023.*"

On June 8, 2023 the DE 23-037 property tax PTAM audit report was issued. The audit report reviewed both issuances of the 2022 municipal property tax bills that summed to $4,816,970. The report identified ($28,184) in municipal property tax adjustments that indicates GSE should recover $4,788,786 in 2022 municipal property tax expenses. The adjustments related to the $227 Town of Charlestown for including the State Education Tax, $28,194 adjustments to the Town of Walpole related to the reported filing vs the 2022 actual amounts on the property tax bill, and a $237 allowance based on a difference between the filing and actual tax obligation due to a lower parcel assessment in Windham. Based on a review of the RR-3.6 property tax filing schedule the Company will need to make the same ($28,184) adjustment plus an additional adjustment of ($66,074) related to Lebanon Parcels 157/1 and 157/2 that audit report indicates the assets were not placed into service and not considered used and useful. The net adjustments to the 2022 municipal installment payments are now $4,788,786 as was presented in the audit report. **Audit Issue #26**

The 2022 state utility tax expense on the filing was $1,288,617. Audit verified four quarterly DP-255 quarterly payments that were $309,897 estimated state utility taxes made in April 15 2022, June 15 2022, September 15, 2022, and December 15, 2022. The Company made a

$49,027 December 31, 2022 true up when the 2022 State Utility Tax bill was received The Company calculated the $4,883,044 property tax expense using both issuances of the 2022 municipal property tax bills. This is a $389,739 difference between the filing and the 408 GL expensed account. This is due to the Company calculating the tax expense a different way as discussed in subsequent paragraph.

The Company books property taxes to the prepaid account using a property tax schedule for 2021 and 2022 based on Towns' Fiscal and Calendar years. The monthly debit entry for Calendar Towns is $209,548 and $241,268 for Fiscal Towns for January 1-June 30, 2022. This is $450,816 per month for both entries The July 1, 2022-December 31,2022 monthly debit entries for Calendar Towns are $228,377 and for Fiscal Towns is $245,637. This is $474,014 per month for both entries The monthly schedule estimates are adjusted accordingly after receiving first half tax bills in May/June and November/December of a tax year. The amounts were reconciled in December 2022. The Company's Accounts Payable department determines whether a town is a Fiscal or Calendar town.

For towns that are on a calendar year basis, the latest property tax bill is used to record the property tax expense for the next 6 months (assuming the time covered on the invoice is 6 months. Towns on the fiscal year basis, the property tax expense is calculated by taking the balance of the prepaid property tax expense, calculating the actual months of prepaid taxes and the difference represents property tax expense for the month. The towns of Derry, Atkinson, Hanover, Londonderry, Salem, and NH DRA are on the Fiscal Year Calendar.

The recurring monthly entries are offset with credits to two accounts:

For January-June 2022:

Property Tax Expense 8830-2-9820-69-5680-4080	$450,816	
Tax Accrual-Municipal Property 8830-2-0000-20-2530-2364		$209,548
Prepaid Taxes-Mun-Property-Oper 8830-2-0000-10-1240-1653		$241,268

For July-December 2022:

Property Tax Expense 8830-2-9820-69-5680-4080	$474,014	
Tax Accrual-Municipal Property 8830-2-0000-20-2530-2364		$228,377
Prepaid Taxes-Mun-Property-Oper 8830-2-0000-10-1240-1653		$245,637

All entries in the Tax Accrual account netted to zero at year-end. The Prepaid Taxes account began the year with $1,137,713 and a year-end balance of $1,276,788.

Audit reviewed the general ledger activity and noted that actual payments made to specific municipalities are debited to the prepaid account, and credited to 8830-2-0000-20-2810-2606, Liberty Energy New Hampshire and after September 2022 to the Liberty Energy Intercompany Accounts Payable account 201010234000.

Adjustments to the prepaid account and accrual account were booked in June and December, based on actual payments made. The final entry in the Tax Accrual account was a debit of $1,012,332 that zeroed the account and was offset to the Prepaid Taxes account.

The Company indicated there were no abatements granted by towns during 2021 and 2022.

Penalties

Audit did not see any expenses related to tax penalties or late payments. The FERC Form 1 did reflect $1,500 in account 426.3, Penalties. In response to DoE data request 5-9 regarding $1,500 noted on Bates I-011, the Company indicated:

> "*The Penalties amount of $1,500.00 charged to account 426.3 in the test year was in payment of two separate Dig Safe violations - Notice of Probably Violation (NOPV) #2022070 for $500.00 and NOPV #2022071 for $1,000.00. The penalties were appropriately charged below the line to account 426.3 and, therefore, were not included in the proposed Revenue Requirement.*"

Audit agrees that the 426.3 account is below the line. There was not a Penalties account in Great Plains, but within SAP is account 3071-50511010426300, reflecting the $1,500.

Audit verified the two incidents to the website for the Enforcement Division of the NH Department of Energy Q2 2022 Non-gas details of violations. The incidents occurred in May in Windham and June in Salem. A review of all other 2022 quarterly reports show that Liberty was not involved in any other non-gas related incidents. Audit also reviewed the Enforcement website for all Liberty/Granite State related incidents since the prior rate case, with the following noted:

Liberty- Granite State Electric

Control #	Date	Municipality	Reporting Party	Operator	Conctractor	Finding	Penalty
2019050	5/21/2019	Lebanon	Liberty GSE	Liberty GSE	Pike Industries	Operator at fault	$ 500
2019069	6/7/2019	Salem	Liberty GSE	Liberty GSE	Busby Construction	Operator at fault	$ 500
						Total 2019	$ 1,000
No violations reported for Liberty Granite State Electric in 2020 or 2021							
22070	5/10/2022	Windham	Liberty GSE	Liberty GSE	American Excavation Corp	Operator at fault	$ 500
22071	6/14/2022	Salem	Liberty GSE	Liberty GSE	Continental Paving	Operator at fault	$ 1,000
						Total 2022	$ 1,500

Income Tax Receivable

Audit reviewed the GSE Account 14601010143000 Income Tax Receivable that indicated there was a ($1,014,482) year-end tax credit balance. The SAP account activity consisted of a ($159,301) November 2022 tax entry based on 2021 tax payments and a $344,428 December 2022 year-end tax entry. The Company indicated the account represents the state cumulative income taxes that GSE has incurred but not paid. GSE owes this amount to Liberty Utilities (Americas) Co. (Parent). Liberty Utilities (GSE) is a member of a consolidated state tax return filed by the parent organization. Audit reviewed a November 2022 ($159,301) entry that was a state tax true up from the tax provision to tax return for the 2021 tax year.

The December 2022 entry for $344,428 represent the quarterly tax payment based on 2022 activities. The ($1,014,482) December 31, 2022 balance is an accumulation of NH state taxes **payable** since the last rate case in 2019 on the stand-alone basis. Audit reviewed the offsetting account detail which is the NH Current State Income Tax expense account 59001010409100. The Company further indicated that GSE makes a true up entry every year after the prior year return is filed on November 15th of each year. The 2021 state return was filed on November 15, 2022 and the 2022 NH State return will be filed on November 15, 2023.

1/1/2022	(947,389)	
	806,362	BET Tax Credit
	(251,496)	Q1 tax provision - BPT tax estimate
	(307,547)	Q2 tax provision - BPT tax estimate
	(499,540)	Q3 tax provision - BPT tax estimate
	(159,301)	2021 Book to Return true up
	344,428	Q4 tax provision - BPT tax estimate
12/31/2022	(1,014,483)	

Audit Issue #1
General Ledger Settlement Set-up

Background

On October 1, 2022, Liberty converted from the legacy Great Plains accounting system and Cogsdale billing system to SAP. Part of the conversion to SAP was described as "*The job system in SAP is known as WBS elements (Work Breakdown Structure). These are used to record and track expenses to specific areas of the business: Capital, Intercompany, and Operations and Maintenance. The process that does this is called settlements. In this process, WBS activities are reflected in 7xxxxx and 8xxxxx natural GL accounts and allocated to be reflected in income statement or balance sheet accounts. Once the settlements are run, each WBS should be zero. When a WBS is not zero it means a transaction, while in the GL, did not "settle" where it needed to be reflected. This could be either a coding issue or a timing issue."*

Issue

Audit noted that coding issues, which Liberty identified when compiling the FERC Form 1, resulted in accounts and/or transactions that appeared in one account in SAP, but were reflected in another account on the FERC Form 1. Audit requested clarification of when the reclassifications and/or "mapping issues" were corrected, and was told that the corrections were not reflected in the SAP system in 2022. Rather, "*throughout 2023, as these* [issues] *have been identified, we are correcting those through manual journal entries or updating the treatment of WBS in the system, as applicable*."

As a result, the 2022 FERC Form 1 does not actually agree with the general ledger accounts at the end of the test year, without the addition to or removal of the numerous "adjustments" which did not take place during the test year, or at the year-end closing of the financial records. In addition, the filing schedules, while reflecting the SAP accounts at year-end, do not literally reflect all of the accounts in the proper location.

Specifically, some (but unknown if all) variances from the FERC Form 1 to the SAP at year-end were identified by Audit to be:

FERC Account	FERC Form 1	SAP Year-end	Variance	
107	$ 15,266,206	$ 15,258,393	$ 7,813.00	
142	$ 29,736,312	$ 29,736,311.52	$ 0.48	Four additional #142 accounts =$18,298.72, in FERC Form 1 #920
146	$ -	$ 964,071,908.63	$ (964,071,908.63)	
163	$ -	$ 54,508.80	$ (54,508.80)	
182.3	$ 4,557,561	$ 5,813,867.39	$ (1,256,306.39)	
184	$ 1,052,518	$ 1,142,090.69	$ (89,572.69)	
186	$ -	$ 165,861.82	$ (165,861.82)	
234	$ (75,125,573)	$ (1,039,197,481.56)	$ 964,071,908.56	
242	$ (32,120,029)	$ (35,849,681.42)	$ 3,729,652.42	
254	$ (6,913,697)	$ (7,746,740.25)	$ 833,043.25	
50500010**440**000	$ -	$ (1,077,479.83)	$ 1,077,479.83	
24672010**593**000	$ -	$ 3,675,811.00	$ (3,675,811.00)	
5xxxxx10**920**000	$ 2,877,428	$ 2,618,648.73	$ 258,779.27	
5xxxxx10**921**000	$ 2,287,231	$ 2,313,715.26	$ (26,484.26)	
xxxxxx10**922**000	$ (8,002,460)	$ (8,501,411.50)	$ 498,951.50	
80111410**924**000	$ -	$ 5,337.34	$ (5,337.34)	
80111810**925**000	$ -	$ 8,263.31	$ (8,263.31)	
xxxxxx10**926**000	$ 3,697,502	$ 3,270,678.45	$ 426,823.55	

Liberty provided information reconciling the annual report to the SAP. Audit could not determine if the adjustments are correct, nor if they represent what the year-end SAP balances should be:

Regarding the $7,813 variance between the FERC Form 1 account #107, Construction Work in Progress, and the total of all SAP account 107 related accounts, the Company noted:

Office Supplies and Expenses	50211010921000	$ 14,040.00	Exclude from 921-Add to 107
CWIP-Ut Plt-FERCE	50500010107000	$ (5,264.43)	Add to 920-Exclude from 107
CWIP-Ut Plt-FERCE	70200010107000	$ (962.31)	Add to 920-Exclude from 107
		$ 7,813.26	

The four additional balance sheet account #142, Customer Accounts Receivable, SAP accounts are reported in the FERC Form 1 in the income statement account #920, Administrative and General Salaries. The accounts were noted to have been mapped to a balance sheet asset account, but were included on the FERC Form 1 in the income statement.

Regarding the $(964,071,908.63) variance between the FERC Form 1 account #146, Accounts Receivable from Associated Companies, and the SAP account 10146000, Intercompany Accounts Receivable, the amount is offset by the variance on account #234, Accounts Payable to Associated Companies. The Company confirmed that the Accounts Receivable from Associated Companies balance was netted with the Accounts Payable to Associated Companies.

Five balance sheet accounts relating to account #163, Stores Expense Undistributed, were also reflected in the FERC Form 1 income statement account #920, Administrative and General Salaries.

The $1,256,306.38 variance between the FERC Form 1 and SAP for balance sheet account #182.3, Other Regulatory Assets, was noted by the Company to be the identification of the following:

CRL Fuel and Commod Cost	24080010182300	$ (833,043.45)	Exclude from asset account 182.3-Add to liability account 254
Salaries and Wages	50000010182300	$ 1,081.00	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$ 1,411.98	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$ (53,144.70)	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$ (37,141.25)	Exclude from balance sheet 182.3-Add to income statement 920
Other Operating Expense	50500010182300	$ (2,380.00)	Exclude from balance sheet 182.3-Add to income statement 920
LTRA R8 Case Cost	17120010186000	$ 165,861.82	Add to balance sheet 182.3-Exclude from asset account 186
Cost Alloc to Cap	50510010922000	$ (316,613.20)	Add to balance sheet 182.3-Exclude from income statement account 922
Cost Alloc to Cap	50510010922000	$ (182,338.46)	Add to balance sheet 182.3-Exclude from income statement account 922
		$ (1,256,306.26)	

The $89,572.69 variance between the FERC Form 1 and SAP for balance sheet account #184, Clearing Accounts, was reportedly identification of certain balances or transactions that should have been excluded from the balance sheet account and included in the income statement account 920, Administrative and General Salaries:

Overtime	50001010184000	$	1,887.18	Exclude from 184-Add to 920
WBS St Lbr-Intrc	85400010184000	$	(32.80)	Exclude from 184-Add to 920
WBS ST OH Ben-Intrc	85411010184000	$	(25.29)	Exclude from 184-Add to 920
WBS ST OH PrlTx-Intr	85411210184000	$	(3.08)	Exclude from 184-Add to 920
WBS ST OH Pn/OPEB-In	85411310184000	$	(3.15)	Exclude from 184-Add to 920
WBS ST OH Prin-Intrc	85411410184000	$	(1.77)	Exclude from 184-Add to 920
Salaries and Wages	50000010184000	$	9,038.97	Exclude from 184-Add to 920
Outside Svs	50030010184000	$	1,722.70	Exclude from 184-Add to 920
Fleet-Fuel	50121010184000	$	20,300.03	Exclude from 184-Add to 920
Fleet-Repair/Main	50121010184000	$	41,361.89	Exclude from 184-Add to 920
Rental Expense	50300010184000	$	950.00	Exclude from 184-Add to 920
Other Operating Exp	50500010184000	$	(74,713.52)	Exclude from 184-Add to 920
BS Lbr Offset	70200010184000	$	(77,732.34)	Exclude from 184-Add to 920
BS Other Offset	70204010184000	$	100,350.11	Exclude from 184-Add to 920
BS Ops OH Benefit	70211010184000	$	(48,551.64)	Exclude from 184-Add to 920
BS OH Payroll Tax	70211210184000	$	(7,306.84)	Exclude from 184-Add to 920
BS OH Pension/OPEB	70211310184000	$	(7,470.08)	Exclude from 184-Add to 920
BS OH Prop Ins	70211410184000	$	(4,205.31)	Exclude from 184-Add to 920
BS Ops Vac Allocation	70211610184000	$	(11,403.32)	Exclude from 184-Add to 920
Lbr Allocation	80000010184000	$	106,666.98	Exclude from 184-Add to 920
OH Benefits	80111010184000	$	33,666.92	Exclude from 184-Add to 920
OH Payroll Tax	80111210184000	$	11,053.76	Exclude from 184-Add to 920
OH Pension/OPEB	80111310184000	$	11,300.70	Exclude from 184-Add to 920
OH Prop Ins	80111410184000	$	6,361.78	Exclude from 184-Add to 920
OH Vacation	80111610184000	$	17,250.90	Exclude from 184-Add to 920
OH Inj&Damage	80111810184000	$	9,854.31	Exclude from 184-Add to 920
OH Bonus	80111910184000	$	11,265.42	Exclude from 184-Add to 920
OH IT Cists	80114110184000	$	17,180.37	Exclude from 184-Add to 920
OH Rent	80114210184000	$	1,481.68	Exclude from 184-Add to 920
OH A&G N-Labr	80117010184000	$	24,471.14	Exclude from 184-Add to 920
WBS ST Serv-Intrc	85403010184000	$	(1,093.70)	Exclude from 184-Add to 920
WBS ST Other-Intrc	85404010184000	$	(42,471.65)	Exclude from 184-Add to 920
WBS ST Fleet-Intrc	84505010184000	$	(61,579.42)	Exclude from 184-Add to 920
		$	**89,570.93**	

Regarding the $165,861.82 variance between the FERC Form 1 account #186, Miscellaneous Deferred Debits, and the SAP account 17120010186000, LTRA R8 Case Cost, the amount is reflected on the FERC Form 1 within account #182.3, Other Regulatory Assets.

Regarding the $964,071,908.56 variance between the FERC Form 1 account #234, Accounts Payable to Associated Companies, and the SAP account #10234000, Intercompany Accounts Payable, the amount is offset by the variance on account #146, Accounts Receivable from

Associated Companies. The Company confirmed that the Accounts Payable from Associated Companies balance was netted with the Accounts Receivable to Associated Companies.

The $3,729,652.59 variance between the FERC Form 1 account #242, Miscellaneous Current and Accrued Liabilities, and the SAP 242 related accounts was noted by the Company to be:

Current REC Obg Non-reg	24672010593000	$ 3,675,811.00	Exclude from Income Statement account 593, add to balance sheet account 242
OH Benefits	80111010926000	$ 17,353.50	Exclude from Income Statement account 926, add to balance sheet account 242
OH Payroll Tax	80111210408000	$ 4,620.26	Exclude from Income Statement account 408, add to balance sheet account 242
OH Pension/OPEB	80111310926000	$ 5,823.05	Exclude from Income Statement account 926, add to balance sheet account 242
OH Prop Ins	80111410924000	$ 5,337.34	Exclude from Income Statement account 924, add to balance sheet account 242
OH Inj&Damage	80111810925000	$ 8,263.31	Exclude from Income Statement account 925, add to balance sheet account 242
OH A&G N-Labr	80117010921000	$ 12,444.13	Exclude from Income Statement account 921, add to balance sheet account 242
		$ 3,729,652.59	

The variance of $833,043.25 between the FERC Form 1 and the SAP for account #254, Other Regulatory Liabilities, was identified to be account 24080010182300, CRL Fuel&Commod Cost, which was mapped to account 182.3 but should have been within account 254. The $833,043.25 was reflected on the FERC Form 1 on the line for account 254.

The variance of $258,778.99 between the FERC Form 1 account #920, Administrative and General Salaries, and the actual SAP 920 related accounts was noted by the Company to be mis-mapped accounts between the balance sheet and the income statement:

Salaries and Wages	50000010140000	2,472.80	Exclude from account noted, included in account 920
Salaries and Wages	50000010163000	2,387.58	Exclude from account noted, included in account 920
Salaries and Wages	50000010182300	(1,081.00)	Exclude from account noted, included in account 920
Salaries and Wages	50000010184000	8,497.50	Exclude from account noted, included in account 920
Overtime	50000010184000	1,887.18	Exclude from account noted, included in account 920
Outside Svs	50030010163000	32.95	Exclude from account noted, included in account 920
Outside Svs	50030010182300	88,873.97	Exclude from account noted, included in account 920
Outside Svs	50030010184000	629.00	Exclude from account noted, included in account 920
Equip & Machin Rents	50050010163000	12,038.96	Exclude from account noted, included in account 920
Fleet-Repair/Main	50122010184000	82.50	Exclude from account noted, included in account 920
Other Operating Exp	50500010107000	5,264.43	Exclude from account noted, included in account 920
Other Operating Exp	50500010163000	4,383.17	Exclude from account noted, included in account 920
Other Operating Exp	50500010182300	2,380.00	Exclude from account noted, included in account 920
Other Operating Exp	50500010184000	(43,574.10)	Exclude from account noted, included in account 920
Elec Pur Power Misc	52001010131000	0.83	Exclude from account noted, included in account 920
BS Lbr Offset	70200010107000	962.31	Exclude from account noted, included in account 920
BS Lbr Offset	70200010142000	(13,353.12)	Exclude from account noted, included in account 920
BS Lbr Offset	70200010184000	(33,506.88)	Exclude from account noted, included in account 920
BS Other Offset	70204010184000	36,899.19	Exclude from account noted, included in account 920
BS Ops OH Benefit	70211010184000	(20,928.41)	Exclude from account noted, included in account 920
BS OH Payroll Tax	70211210184000	(3,149.64)	Exclude from account noted, included in account 920
BS OH Pension/OPEB	70211310184000	(3,220.01)	Exclude from account noted, included in account 920
BS OH Prop Ins	70211410184000	(1,812.72)	Exclude from account noted, included in account 920
BS Ops Vac Allocatin	70211610184000	(4,915.45)	Exclude from account noted, included in account 920
Lbr Alloc	80000010163000	35,666.14	Exclude from account noted, included in account 920
Lbr Alloc	80000010184000	62,982.99	Exclude from account noted, included in account 920
OH Benefits	80111010184000	21,005.17	Exclude from account noted, included in account 920
OH Payroll Tax	80111210184000	6,896.56	Exclude from account noted, included in account 920
OH Pension/OPEB	80111310184000	7,050.63	Exclude from account noted, included in account 920
OH Prop Ins	80111410184000	3,969.19	Exclude from account noted, included in account 920
OH Vacation	80111610184000	10,763.03	Exclude from account noted, included in account 920
OH Inj&Damage	80111810184000	6,148.21	Exclude from account noted, included in account 920
OH Bonus	80111910184000	7,028.62	Exclude from account noted, included in account 920
OH IT Costs	80114110184000	10,719.03	Exclude from account noted, included in account 920
OH Rent	80114210184000	924.44	Exclude from account noted, included in account 920
OH A&G N-Labr	80117010184000	15,267.82	Exclude from account noted, included in account 920
WBS ST Lbr-Intrc	85400010142000	29,179.04	Exclude from account noted, included in account 920
WBS ST Lbr-Intrc	85400010184000	(32.80)	Exclude from account noted, included in account 920
WBS ST Other-Intrc	85404010184000	(6.83)	Exclude from account noted, included in account 920
WBS ST OH Ben-Intrc	85411010184000	(25.29)	Exclude from account noted, included in account 920
WBS ST OH PrlTx-intr	85411210184000	(3.08)	Exclude from account noted, included in account 920
WBS ST OH Pn/OPEB-in	85411310184000	(3.15)	Exclude from account noted, included in account 920
WBS ST OH PrIn-Intrc	85411410184000	(1.77)	Exclude from account noted, included in account 920
		258,778.99	

The $26,484.13 variance between the FERC Form 1 account 921, Office Supplies and Expenses, and the SAP account 921 related general ledger accounts, as above, was noted to be accounts and/or entries that were in the FERC Form 1 in the income statement, but in the actual SAP in balance sheet accounts. Specifically:

Comp Exp-Repair	50211010921000	14,040.00	107, Construction Work in Progress
OH A&G N-Labr	80117010921000	218.89	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	99.20	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	169.42	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,576.06	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	33.27	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	148.82	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	392.85	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,996.17	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	42.36	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	263.84	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	92.29	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	710.01	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	570.27	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,805.73	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	92.83	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	19.67	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	156.90	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	103.62	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	831.18	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	15.73	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	105.02	242, Miscellaneous Current and Accrued Liabilities
		26,484.13	

The $498,951.66 variance between the FERC Form 1 account 922, Administrative Expenses Transferred-Credit, and the SAP 922 related accounts was noted by Liberty to be:

Cost Alloc to Cap	50510010922000	$	(316,613.20)	reflected within account 182.3
Cost Alloc to Cap	50510010922000	$	(182,338.46)	reflected within account 182.3
		$	(498,951.66)	

Several entries, summing to the $5,337.34 variance between the FERC Form 1 and the SAP account 924, Property Insurance, were excluded from that account on the FERC Form 1 and included in the balance sheet account 242, Miscellaneous Current and Accrued Liabilities.

OH Prop Ins	80111410924000	93.88	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	42.55	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	72.66	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,104.88	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	14.27	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	63.83	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	168.49	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,285.07	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	18.17	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	113.17	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	39.58	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	304.53	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	244.59	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,203.39	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	39.81	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	8.44	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	67.30	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	44.44	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	356.50	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	6.75	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	45.04	Excluded from 924-Added into 242
		5,337.34	

The $8,263.31 variance between the FERC Form 1 account 925, Injuries and Damages, and the SAP 925 related account total was noted by Liberty to be the following entries that posted to 925, but should have posted to account 242, Miscellaneous Current and Accrued Liabilities. The FERC Form 1 reflects what the year-end balances notedly should have been, not what the SAP reflected:

OH Inj&Damage	80111810925000	145.36	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	65.87	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	112.50	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,710.59	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	22.09	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	98.82	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	260.86	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,989.55	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	28.14	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	175.21	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	61.27	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	471.47	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	378.68	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,863.09	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	61.64	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	13.06	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	104.18	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	68.81	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	551.93	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	10.45	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	69.74	Excluded from 925-Added into 242
		8,263.31	

<u>The $23,176.55 variance between the FERC Form 1 and SAP account 926</u>, Employee Pensions and Benefits expense account was identified by the Company to be the result of several transactions that were mis-mapped to account 926 in SAP, and should have been included in account 242, Miscellaneous Current and Accrued Liabilities. The FERC Form 1, as above, was a reflection of what the ending balances notably should have been, not what the general ledger actually showed.

OH Benefits	80111010926000	305.24	Excluded from 926-Added into 242
OH Benefits	80111010926000	138.33	Excluded from 926-Added into 242
OH Benefits	80111010926000	236.25	Excluded from 926-Added into 242
OH Benefits	80111010926000	3,592.34	Excluded from 926-Added into 242
OH Benefits	80111010926000	46.39	Excluded from 926-Added into 242
OH Benefits	80111010926000	207.52	Excluded from 926-Added into 242
OH Benefits	80111010926000	547.84	Excluded from 926-Added into 242
OH Benefits	80111010926000	4,178.21	Excluded from 926-Added into 242
OH Benefits	80111010926000	59.08	Excluded from 926-Added into 242
OH Benefits	80111010926000	367.93	Excluded from 926-Added into 242
OH Benefits	80111010926000	128.69	Excluded from 926-Added into 242
OH Benefits	80111010926000	990.12	Excluded from 926-Added into 242
OH Benefits	80111010926000	795.25	Excluded from 926-Added into 242
OH Benefits	80111010926000	3,912.64	Excluded from 926-Added into 242
OH Benefits	80111010926000	129.45	Excluded from 926-Added into 242
OH Benefits	80111010926000	27.43	Excluded from 926-Added into 242
OH Benefits	80111010926000	218.79	Excluded from 926-Added into 242
OH Benefits	80111010926000	144.50	Excluded from 926-Added into 242
OH Benefits	80111010926000	1,159.09	Excluded from 926-Added into 242
OH Benefits	80111010926000	21.95	Excluded from 926-Added into 242
OH Benefits	80111010926000	146.46	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	102.43	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	46.42	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	79.28	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,205.43	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	15.57	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	69.63	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	183.84	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,402.01	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	19.82	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	123.46	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	43.19	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	332.24	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	266.85	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,312.91	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	43.44	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	9.20	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	73.41	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	48.48	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	388.94	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	7.36	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	49.14	Excluded from 926-Added into 242
		23,176.55	

Recommendation

Liberty should have ensured that the actual financial records within the new SAP system were accurate, prior to filing the current rate case.

All transactional or system mapping adjustments should have been addressed. Because of the quantity of noted adjustments, and the time required to identify variances among the FERC Form 1 accounts, Audit is unable to determine if the reported adjustments are accurate nor if they represent all of the adjustments that should have been done.

Company Comment

Liberty Granite State ("Liberty") appreciates Audit Staff's review and efforts during its audit, specifically, recognizing that additional efforts by Audit Staff were required to translate how accounts and transactions previously reflected in our legacy system now appear in SAP. As a result of this transition, additional audit explanations were necessary that required additional time and attention from Audit Staff. We also appreciate that we need to take the lead on providing those "translations" and making the transition to the new accounting system as seamless as possible for Audit Staff and other parties in this proceeding.

That said, the Company does not agree with Audit Staff's conclusion that the Company failed to ensure that its actual financial records within the new SAP system were accurate prior to filing the pending rate case. The financial records are accurate. There are simply some differences in the way that costs are recorded in one system or the other. These differences are known and allow for "mapping" of data from the new system to the protocols required for financial reports, such as the FERC Form 1. It is also important to note that the Company's 2022 financial statements were audited by the Company's independent auditors, Ernst & Young ("EY") and a copy of EY's audit opinion was previously filed as part of the Company's standard filing requirements, Puc 1604.01(a)(13)… In its audit opinion, EY concluded that:

> …[the] financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022, and the results of its operations and its cash flows for the year then ended in accordance with generally accepted accounting principles.

In addition, the Company had EY review the Company's FERC Form 1, and EY similarly determined the FERC Form 1 to be accurate…Liberty has also provided information to Audit Staff to substantiate all adjustments.

Also, please note that, subsequent to the parent company closing the books for 2022 year-end, Liberty identified "Unadjusted Differences" of approximately $848k that were discussed with EY and management. Liberty has correctly reflected those amounts in the revenue requirement, as described in responses to DOE 10-21 and DOE 11-14. "Unadjusted Differences" are not unusual in any reporting year and will occur from time to time, regardless of a change in accounting systems. With the Unadjusted Differences reflected in the revenue requirement, the FERC Form

1 maps directly to the data recorded in Liberty's financial system. The Company has provided a trial balance to Staff that provides the direct mapping to the FERC Form 1.

Audit Comment

Audit understands the efforts put forth by the Company to deal with a system conversion, the compilation of two full rate filings (Granite State and EnergyNorth), and the completion of the FERC Form 1.

Audit is also aware of, and had read, the E&Y financial reports. Language included in the Company Response is language typically found in the disclosure of any financial review conducted by external auditors. Those disclosures also include the fact that the information in the report is based on Management's representation.

Audit also understands that the E&Y audit was conducted in conjunction with the APUC corporate "natural" account as the primary focus. While the audit did not result in any material misstatements, the external auditors did not appear to appreciate the importance of the verification and validation of the reported figures within the FERC Form 1 to the SAP year-end balances.

Liberty also informed Audit that "*The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement…capitalized amount was not recorded for GAAP purposes to align with the Parent Company (APUC) Form 10-K filing and not have differences between those GAAP filings.*"

The Company must ensure that the financial accounts of Granite State Electric truly support the accounts as reflected in the FERC Form 1. Mapping issues, or translations of portions of accounts are not consistent with the FERC USoA.

Audit Issue #2
Accumulated Depreciation and Cost of Removal

Background

Audit compared the year-end SAP balances to the FERC Form 1 and to the Company's Revenue Requirement schedules.

Issue

The filing schedule RR-4 indicates the Accumulated Depreciation balance is $123,210,870. This is a $120,158 difference compared to the 2022 FERC Form 1. The variance is comprised of a ($1,412.71) balance in account 15520010108000 Accumulated Depreciation-FC-Leg, and $121,570.85 balance in the RWIP account 15550010108100.

Accumulated Depreciation and Amortization

		SAP and FERC Form 1	RR-4, Line 2	CPR
15030010108000	Accrued Cost of Removal	$ (8,010,584)	$ (8,010,584)	
15501010108000	Acc Dep-Plant in Service	$ (102,547,907)	$ (102,547,907)	
15520010108000	Acc Dep-FC-Legacy	$ (1,413)		
15551010108000	RWIP Reclass	$ -	$ -	
15501010108000	Acc Dep-Plant in Service	$ (188,068)	$ (188,068)	
15550010108100	RWIP	$ 121,571		
26150010108110	Long term Cost of removal	$ (258,610)	$ (258,610)	
15501010111000	Accumulated Dep-Plant in Service	$ (12,205,701)	$ (12,205,701)	
	FERC Form 1	**$ (123,090,712)**	**$ (123,210,870)**	**$ (123,180,534)**
	variance to SAP and FERC Form 1		$ (120,158)	$ (89,822)

Neither account highlighted in yellow is included in the filing. The Company provided the following explanation: "*$121,571 in RWIP is Removal Work in Progress and therefore would not be included in the revenue requirement. The $1,413 in Legacy Costs represent two salvage cash payments. These amounts should have been included in the revenue requirement. They were inadvertently excluded because they were posted directly to the legacy account and therefore never settled properly through a WBS# in SAP to depreciation reports. The Company will consider this, along with any other changes identified during the discovery process, in its next update of the revenue requirement in this proceeding.*"

The 2022 CPR records indicate the test year Cost of Removal charges are ($1,472,496) while the FERC Form 1 page 219 indicates ($1,563,731). This is a $91,235 difference.

Recommendation

Audit agrees that the Retirement Work in Progress account should not be part of the filing, because CWIP is also not included. However, Audit does recommend that the filing schedule RR-4 be updated with the $(1,413), as the Company noted.

The Cost of Removal and CPR records should agree. The Company should perform any necessary adjusting journal entries and adjust any filing schedules to reflect the adjustment.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding and will perform the necessary adjusting journal entries.

Audit Comment

Audit concurs, and requests that copies of any adjusting journal entries be provided to Audit within 30 days of this Final report.

Audit Issue #3
Repeat Issue
Capitalizing Fleet/Equipment Depreciation

Background

The Company has been capitalizing fleet/equipment depreciation since 2018 when they adopted FASB ASC 360. In the Audit Report, Audit Issue #3 of the DE 19-064 audit work, it was noted that the capitalization is the monthly depreciation expense of grouped asset 8830-3920, multiplied by the quarterly fleet depreciation rate capitalized to CWIP jobs through inclusion in the BRD calculation.

Issue

The Company capitalizes a portion of depreciation on vehicles in account #392 and equipment in account #396 to FERC account 107 CWIP. The calculated depreciation is posted to regulatory accounts 55056010403000 Capitalized Equipment and 55057010403000 Capitalized Fleet. A journal entry is then done each month to move a percentage of this depreciation to the 107 CWIP account where these amounts are allocated across capital projects. For 2022:

55056010403000 Capitalized Depreciation- Equipment	($52,491)
55057010403000 Capitalized Depreciation-Fleet	$79,367
Net Capitalized Depreciation	$26,876

In response to this issue in the prior rate case audit, Liberty noted:

"*The capitalization of depreciation on construction vehicles to account 107 balance is appropriate under the guidance set forth by US GAAP* [Financial Accounting Standards Board FASB] *standard ASC 360. The entry to capture the capitalization of vehicle depreciation used in construction activities is a debit to CWIP, account 107 and a credit to depreciation expense account 403. Thus, the depreciation expense is not overstated and the Accumulated Depreciation is not understated.*"

Recommendation

As noted in the prior report, Audit recommends that the Company comply with the FERC Uniform System of Accounts, make any adjustments to filing schedules removing the capitalized equipment/fleet charges from the filing.

The Company must also adjust the Plant in Service balances which have been impacted by the capitalization of fleet depreciation, for all years 2018 through current.

Company Response

As to the adjustment to Plant in Service balances for 2018 through current, Liberty disagrees with Audit's finding as the Company has followed the guidance set forth by US GAAP standard FASB ASC 360 since 2018. As such, no adjustments to the Plant in Service balances are required.

As to the adjustment to the Rate Years, Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

<u>Audit Comment</u>

Audit is unclear regarding the disagreement for plant balances impacted since 2018, but the Company's agreement to adjust plant in service for the test year only, and in the filing only.

Audit restates that for all years from 2018 through current, the Company should not capitalize fleet depreciation.

Audit conferred with a representative from the FERC Enforcement division, who supported the Audit staff's interpretation of "depreciation" that can be included in Construction Work in Progress, and agreed that fleet depreciation generally does not conform with the FERC Uniform System of Accounts. That representative noted that regulated utilities must conform to FERC over GAAP and ASC 360 in this instance.

Audit also understands that this issue should be resolved within the context of this rate case, and defers to the Regulatory division of the Department of Energy and the Company to ensure a clear and concise resolution of this ongoing issue.

Audit Issue #4
Repeat Issue
EAP Upgrades CIAC

Background

The Company did software upgrades that were recovered through the System Benefits Charge.

Issue

On June 1, 2023 the DE 21-133 Energy Assistance Program Final Audit Report was issued. A repeat Audit Issue #1 identified $140,000 in EAP costs the Company was authorized to recover on June 1, 2021 per Order 26,485 through the EAP/SBC funding mechanism. The Order included:

- *"Liberty originally requested recovery of $195,666 in the joint petition"*
- *"Liberty acknowledged during the March 4, 2020, hearing that, upon further refinement, its actual costs were approximately $160,000"*
- *"At the hearing, Liberty requested approval for recovery in the amount of $140,000, consistent with the Settlement Agreement, stating that it would request recovery of the remaining costs (approximately $20,000) in a pending rate case"*
- *"In the Settlement Agreement…. they agreed that Liberty had prudently incurred costs of $140,000 to implement the changes required by Order No. 26,132. The Settlement Agreement contained a table showing that an invoice had been incorrectly charged to Liberty's project, so that the correct total was $160,753 rather than $195,666. It also noted that Liberty agreed to seek recovery of $140,000 from EAP funds in this docket and to request the remaining **$20,753** in a pending rate case"*

The June 2023 Audit Report further indicates that Liberty, in their updated March 15, 2023 EAP reconciliation filing, recovered the $140,000 costs associated with the required EAP technical system upgrades.

Since the $140,000 EAP billing system upgrade costs were recovered through SBC funds the Company should include the plant additions to rate base without at least entering the reimbursement costs as a Contribution in Aide of Construction (CIAC).

Recommendation

The Company should remove $140,000 EAP billing upgrade plant additions from the filing schedule, general ledger, and continuing property records, or provide evidence that the offset to CIAC has been booked and the filing updated to reflect that entry.

In response to the Audit Issue #6 in the DE 19-064 audit report issued in January 2020, in which $168,498.10 had been booked to plant in service, the Company noted:

"*The Company agrees that due to the difference in timing between the incurrence of costs in 2018 and the receipt of reimbursement funding from the SBC (expected during 2020) the costs should be removed from the rate case filing. As the funds received from the SBC will be treated as CIAC and offset the cost of the upgrade, if the reimbursement was received in the same year the costs were incurred there would be no impact on plant in service. However, as the rate case* *has a test year that ended December 31, 2018, the costs should be removed to avoid setting rates that include the system upgrade costs.*"

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

While Audit concurs with the Company adjusting the filing, the Company is requested to provide the adjusting journal entries and/or removal from the continuing property records.

Audit Issue #5
Project Addition Backup

Background

Audit reviewed twelve 2019-2022 project plant additions that included the budgeted vs. actuals amounts, charge detail, project cost of removal, Project Retirement entries, Business Cases, Project Capital Expenditure Forms, Change Order, and Closeout support.

Issue

Budget vs. Actual

The Company, when asked to provide reasons for projects budgeted vs. actual amount variances, indicated to Audit to review the specific business cases/project closeout details. On all the projects reviewed, the Business Cases/Project Closeouts did not give a specific reason other than in some instances projects were reallocated to other ones to meet budget priorities during the year. The Project Closeout Reports also contained many large variances when compared to what was actually spent.

Bids

The Company, on a few projects, indicated projects were done internally and that is why they were not put out to bid. The Company did not provide the bid details for the 8830-2083 Ten Year Inventory Improvement other than indicating they found a contractor that met their needs. Based on a review of a few projects the cost detail is solely for contractors so that means the project was not done internally and the Company should have gone out to a competitive bid if one was not done. This affects the following projects:

Should have been bid competitively:
Project 8830-1956 Install 13L2-9L3 Feeder Tie
Project 8830-2025 IT Systems and Equipment Blanket

Cost of Removal and Retirements

The Company for several projects did not specify a reason for why any cost of removal (COR) or retirement entries were not done. The Company did specify install only projects do not have any cost of removal entries. The Company did acknowledge that they were presently behind on retirement entries because of the recent conversion to SAP/PowerPlan in October 2022 and will need to get caught up.

No COR entries Completed
Project 8830-2127 IT Systems Allocations-Corporate
Project 8830-2241 Feeder Getaway Cable
No Retirement Entries Completed
Project 8830-1954 Mt. Support Lebanon 16L2-L5 Feeder
Project 8830-1956 Install 13L2-9L3 Feeder Tie
Project 8830-2025 IT Systems and Allocations
Project 8830-2127 IT Systems Allocations-Corporate
Project 8830-2139 URD Cable Replacement
Project 8830-2119 Transformer Upgrade
Project 8830-2241 Feeder Getaway Cable
Project 8830-2210 Distributed Street Light Replacement

Missing Documentation

The Company was missing specific documentation for Business Cases, Project Capital Expenditures Form, and Project Closeouts. The following projects were missing key documentation.

Project	Document
8830-1956	Project Capital Expenditure Form
8830-2127	Project Capital Expenditure Form
8830-2083	Project Closeout Form

Unitized Amount Varies from Project Closeout Report

Several projects' actual unitized plant in service amount is different than what was indicated on the signed project closeout forms.

Project	Project Closeout	Actual Plant in Service	Difference
8830-1956	$227,672	$246,037	$18,365
8830-2024	$82,118	$257,404	$175,286
8830-2013	$136,432	$185,925	$49,493
8830-2139	$36,295	$235,107	$198,812
8830-2119	$33,293	$38,828	$5,535
8830-2241	$122,213	$119,779	($2,234)
8830-2210	$81,617	$133,309	$51,695

Materials and Supplies Journal Entries not Supported with Inventory Ticket or Detail

The materials support provided by the Company did not contain any invoices or historical inventory tickets details, rather, solely a journal entry of the transaction amount and quantity.

2019		2021	
Project	Description	Project	Description
8830-1932	Lebanon High Voltage	8830-2119	NN Transformer Upg.
8830-1954	Install Mt. Summit Feeder Cable		
8830-1956	Install 13L2 Feeder Cable		

2020		2022	
Project	Description	Project	Description
8830-2024	LED Streetlight Replacement	8830-2241	Feeder Replacement
		8830-2210	Streetlight Repl.

AFUDC Embedded File

The Company indicated the AFUDC backup was in an embedded file but there were no embedded files other than the GL transaction Audit sampled. This affects the following projects.

2019		2020	
Project	Description	Project	Description
8830-1954	Install Mt. Summit Feeder Cable	8830-2024	LED Streetlights
8830-1956	Install 13L2 Feeder Cable		

Overhead Embedded File and Percentages Exceeding 30%

The Company indicated they provided the Overhead calculations/backup for the plant additions review in an embedded file that was not attached to the provided file. A number of projects have an overhead rate exceeding 30% that seems rather elevated for the amount of the project. The following projects had an overhead rate that exceeded 30%.

Year	Project	Description	Overhead %
2019	8830-1962	Lebanon Low Area Voltage	51.78%
2019	8830-1954	Install Feeder Tie Lebanon	47.58
2020	8830-2024	Install LED Streetlights	45.23
2020	8830-2025	IT Systems and Equipment Blanket	105.14%
2020	8830-2013	Distribution Asset Replacement	48.42%
2021	8830-2139	URD Cable Replacement	54.04%
2021	8830-2119	Transformer Upgrades	58.06%
2022	8830-2210	Install LED Streetlights	39.44%

Recommendation

The Company should make any adjustments to the filing schedules, to the correct actual plant in service balances for projects based on the explanations for variances.

The Company should review project budgeted vs actual costs and document why there are variances.

Going forward the Company should book retirements/Cost of Removal in a more timely manner.

The Company should focus more on following the LU Capital Expenditure Policy having specific project documentation such as Business Cases, Capital Expenditure Forms, and Project Closeouts. The Company should pay better attention to project bids as the Company indicated two projects were done internally when they were not.

The Company should have provided actual materials inventory invoices or tickets rather than solely journal entries, so a detailed review of materials used could have been accomplished by Audit.

The Company should have provided the complete AFUDC documentation, as the file provided did not contain an embedded file other than the sample entry Audit chose for the addition review.

The Company should have provided the complete Overhead backup, as the file provided did not contain an embedded file other than the sample Audit chose for the addition review. The overhead rates on several of the projects reviewed exceeded 30% and the Company should look for ways to lower this percentage.

As noted by the Company in response to Audit Issue #2 in the DE 19-064 audit report dated 1/16/2020:

"*In addition to improvements bulleted above (monthly budget meetings, increased level of review, designated resources and improved processes around recording and tracking accruals), the Company has also implemented a dedicated operations finance resource to oversee financial planning and reporting aspects of the Operations and Engineering groups. Additionally, the Company is in the final planning stages for tracking and allocating burdens and overheads in a manner that will allow project managers to better forecast and manage the financial budget of capital projects.*

As previously mentioned in this and prior rate cases, the management of capital projects often involves changes in scope and shifts in focus of projects to be completed in order to conduct reliable, safe and efficient operation of the business. With a newly dedicated resource supporting the operations and engineering groups, the company will be more focused on developing and implementing improvements to the process around capital spending."

<u>Company Response</u>

Please see below for the Company's response to the Audit recommendations. Please note that the responses are in order of appearance as presented in the recommendation.

Budget vs. Actual

Since actual costs were used to calculate the plant in service balances, no adjustments to the Company's filing schedules to correct actual plant in service balances are needed.

Bids

The Company agrees, and notes that the Company reviews budgeted vs actual costs and documents variances through Liberty's change order process as documented in the LU Capital Expenditure Policy.

Cost of Removal and Retirements

The Company agrees. Liberty is working towards a more timely recognition of actual and retirement reporting.

Missing Documentation

The Company follows the LU Capital Expenditure Policy. However, the Company acknowledges that two projects were incorrectly identified as being completed internally and upon further review were determined to have been completed by a third party.

Unitized Amount Varies from Project Closeout Report

Projects typically have late charges for adjustments after the required close document 90 days from completion. These charges can cause a difference between the close-out and the unitized in-service cost. A few selected projects are also blanket projects, for example, 8830-2013 asset replacement, that opened and closed every year.

Materials and Supplies Journal Entries not Supported with Inventory Ticket or Detail

The Company provided Audit with the best information available for a detailed review to be accomplished. The Company disagrees that the only information it provided was journal entries, as the Company also provided inventory transaction details in the subledger associated with the transaction requested. The information provided indicated the job name and number for each project that materials were charged to as well as the quantity and the cost at the time of issue from stock. Additionally, the information provided included a description of the material that was used for those particular jobs. Lastly, the information provided included the cost of each item as it left the warehouse. Materials are issued to jobs on an average cost method, so the price of materials potentially moves as material is received. The Company can provide information on its purchase price, but it will not likely match due to the recalculation of the unit costs at the time of receipt.

AFUDC Embedded File

The Company would like to clarify that what was provided in the Company's prior response to Audit's question were not sample entries, they were actual entries documenting how AFUDC was calculated.

Overhead Embedded File and Percentages Exceeding 30%

The overhead rate is a function of overhead costs that include administrative and general operating costs necessary to maintain daily operations and administer the business.

Audit Comment

Audit appreciates the specific response by the Company.

- Audit understands the Company booked the appropriate actual project costs to plant in service, so the Company feels no adjustments to the filing schedule are necessary. Audit reminds the Company that project documentation such as project closeouts should include a detailed analysis of why projects over budget or under budget compared to the actual costs. Going forward, the Company should pay closer attention to why some projects are over or under budget this will help to better manage Company resources more efficiently.

- Audit appreciates that the Company acknowledged two projects should have been put out to bid and the Company is trying to follow the internal LU Capital Policy.

- The Company should continue to address the cost of removal and retirement entries to ensure Plant is not overstated.

- Adherence to the LU Capital policy so project documentation for Business Cases, Change Order, Authorizations, and Project Closeouts are completed and accurate should be more closely monitored.

- Audit appreciates the response by the Company that there were late charges 90 days after the project close documentation that explain the difference between the unitized to plant in service figure compared to the project closeout. Going forward the Company should complete Project Closeout Reports that more accurately reflect the actual project costs that were unitized to plant in service.

- Audit appreciates the clarification regarding materials. The Company did provide materials backup that was identical to the GL entry detail that included the cost and the specific items used. Audit appreciates the Company clarifying the average cost method with regard to historical plant record transactions that the figures would be different as they leave the warehouse based on how the allocations are done.

- Audit appreciates the response by the Company regarding the AFUDC entries. Audit was able to review the actual GL entry but going forward the Company should provide the contractual details for the borrowed amount and debt portion. Audit appreciates the response with regards to overhead but reiterates the Company going forward should keep the overhead charges to the minimum costs needed to complete projects.

Audit Issue #6
Cost of Removal Booked Incorrectly

Background

Audit reviewed cost of removal generally and in the context of the specific plant additions tested as part of this audit.

Audit Issue

FERC requires that Cost of Removal entries be debited to Accumulated Depreciation. Audit noted charges to accounts 1084 and 242 throughout the testing of specific plant addition projects:

2019: Project 8830-1962
Solely 8830-2-0000-20-2124-2420 Accrued COR $19,278 entries done January 2019.

2020: Project 8830-2024
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $17,978 entries November and December 2020 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $51,907 entries are July-December 2020

2020: Project 8830-2025
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $7,724 entries November and December 2020 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $33,809 entries are June 2020 to August 2022.

2021: Project 8830-2139
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $5,350 correctly posted.
8830-2-0000-20-2124-2420 Accrued Cost of Removal $1,467

2022: Project 8830-2210
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $13,874 entries February and March 2021 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $242 entries are November-December 2019

The Company should not be debiting the 242 Accrued Cost of Removal account.

As noted in the DE 19-064 Audit Issue #7:

> *FERC account #**108 st**ates "at the time of retirement of depreciable electric utility plant, this account* ***shall be charged*** [debited] ***with the book cost of the property retired and the cost of removal*** *and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirement, cost of removal and salvage are entered originally in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder…"*
>
> *FERC account #242 states "This account shall include the amount of all other current and accrued liabilities not provided for elsewhere appropriately designated and supported so as to show the nature of each liability. Items (nonmajor only) 1. Dividends declared but not*

paid 2. Matured long-term debt 3. Matured interest 4. Taxes collected through payroll deductions or otherwise pending transmittal to the proper taxing authority."

The Company Response to the DE 19-064 Audit Issue #7 included:

"***While the Company will follow the FERC Uniform System of Accounts by recording its cost of removal in Account 108 Accumulated Depreciation for regulatory purposes****, the Company will continue to utilize Account 242 Miscellaneous Current and Accrued Liabilities for GAAP financial statement reporting purposes. Account 108 will be utilized for day to day entries.* ***A journal entry for the cost of removal (reclassify Account 108 to Account 242) will be made on the consolidating company level to conform to GAAP reporting requirements***." Emphasis added.

Audit Recommendation

Audit reminds the Company of its commitment to record cost of removal entries in compliance with the FERC Uniform System of Accounts, and appreciates that it appears they are trying to comply.

The reader is reminded of the Company response to the variance noted in **Audit Issue #2** of this report.

Company Response

On the regulatory ledger, the Company follows the FERC Uniform System of Accounts by recording its cost of removal in Account 108 Accumulated Depreciation for regulatory purposes.

On the GAAP ledger, for GAAP financial statement reporting purposes, the Company utilizes Account 242 Miscellaneous Current and Accrued Liabilities. Account 108 is utilized for day-to-day entries. A journal entry for the cost of removal (reclassify Account 108 to Account 242) is made on the consolidating company level to conform to GAAP reporting requirements.

The regulatory ledger was provided to Audit for review. The Company records cost of removal in the proper account and therefore the Company does not view this as an audit issue that impacts this rate case.

Audit Comment

Audit reviewed the complete activity of the Accumulated Depreciation Cost of Removal account 108, and noted its accurate use beginning in 2020. During 2019 and prior, the 242 account had been debited rather than the 108 account. However, within the samples tested, use of the 242 account was noted.

Audit Issue #7
Materials Expense

Background

The Company inventory reports, and GL figures are different from one another.

Issue

The Company, in the response to DOE Staff Data Request 4-8, provided 2020-2022 Historical Stock Status Detailed Inventory Reports. The Excel attachment DOE 4-8-1 and DOE 4-8-2 indicate the December 2022 Historical Stock balance per the report is $4,259,944 while the GL accounts summed to $3,759,408. This is a ($500,536) difference.

Account #	Amount	DOE 4-8-1 and 4-8-2	Variance
12100010154000	$4,259,944		
12100510154000	($501,827)		
12101510154000	$1,291		
Total	$3,759,408	$4,259,944	$(500,536)

Recommendation

The Company should make any adjustments to the filing schedule as the inventory reports and GL figures should reflect the same figure.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company response.

Audit Issue #8
Timing of Recording Transactions

Background

Account 131 (Cash): Per the FERC Form 1 and the General ledger the account balance the Company reported was $43,238,110.63 as of 12/31/2022.

Issue

Account 131 (Cash): The Company provided a cash reconciliation showing a ($210,283,306.62) difference between the SAP GL and the reconciliation that detailed reported GL balances. The Company advised that an entry posted after the reconciliation was completed.

Recommendation

The Company should ensure timely recording of entries to avoid large discrepancies between the reconciliation and the general ledger, and should have ensured that all roll-forward balances were properly recorded from Great Plains to SAP in a more timely manner.

Company Response

Account 131 (Cash)

Based on the above description of the issue, Liberty disagrees with the conclusion that a non-timely recording affected the Audit's review. As noted above, the Company identified a discrepancy and made an adjusting entry prior to filing its rate case. That adjustment was also made prior to EY's audit of the Company's financials and FERC Form 1.

Audit Comment

Audit understands that the filing reflected the adjustment. Audit reviews the financial statements, and internal controls such as reconciliations, to ensure that the general ledger itself is appropriate.

Audit Issue #9
Accounts Receivable Aging

Background

Audit requested and was provided with the customer level aged accounts receivable listing as of December 31, 2022.

Audit Issue

The aged accounts receivable listing is the total of 44,826 specific customers, the total of which reflected $21,567,622.35. Audit was unable to verify the total per the aged receivable to any combination of the nine SAP year-end balances, which in full, sum to $29,736,311.52.

A reconciliation was provided demonstrating:

Accounts Receivable debit balances	$19,814,926.03
Accounts Receivable Credit balances (Unapplied Payments)	$ (609,186.12)
Net Accounts Receivable	$19,205,739.91

The Company noted that the "*aged trial balance report did not tie out exactly to the general ledger, but it was determined that the variance was immaterial*", $6,354.47, or 0.03% when $19,205,739.91 was compared to another unknown receivable figure of $19,212,094.38.

Audit Recommendation

Audit encourages the Company to ensure that "*additional reports*" developed since the year-end reconciliation "*to clarify differences (mostly due to timing), but these reports were not available in December 2022*" function in a manner that will allow a true reconciliation of the supporting aged listing to the specific general ledger account or accounts.

Company Response

In January 2023, the Company developed a report titled "Display Totals for Posting" to reconcile any timing differences between the A/R aged trial balance report and the General Ledger allowing a reconciliation of the A/R aged trial balance to the specific GL account. The report provides the detail by GL account of the items that did not post from the CIS system to the GL. The Company performs this reconciliation of the A/R aged trial balance report every month, in addition to reconciling the individual general ledger account balances monthly.

The Company has not experienced any errors with items not posting to the general ledger for Granite State since January 2023.

Audit Comment

Audit appreciates that a report has been developed, and looks forward to reviewing the implementation of its use within the next audit.

Audit Issue #10
Interest on Customer Deposits

Background

Audit reviewed activity within the Interest Accrued from Customer Deposit general ledger account, within Great Plains, and requested clarification of an entry in the amount of $259.59 that posted 9/27/2022 in 8830-2-0000-20-2116-2370.

Audit Issue

The Company noted that the figure represented interest for 241 customers' deposits. As a result of the request for clarification, the Company identified a miscoding between Granite State Electric and EnergyNorth, which was identified and corrected during the test year. Liberty also noted that they "*discovered a coding error for 57 of the 3,219 GSE accounts with security deposits, which has prevented these customers from receiving their interest. The Company will make the correction and post the missing interest to the customers' accounts. The total amount of security deposits held for these 57 accounts as of December 2022 is $10,530. The estimated deposit interest owed based on the 5.5% rate in effect for that period is $145*."

Audit Recommendation

Audit reminds the Company that it must comply with the Puc 1200 rules and ensure that all customers have the monthly interest applied.

Company Response

Liberty concurs. The underlying error has been corrected.

Audit Comment

Audit concurs with the Company response and will verify the accuracy of it as part of the next rate case audit.

Audit Issue #11
Interest Income

Background

Prior to 9/30/2022, the Interest Income had been reported on GP general ledger account 8830-2-0000-40-4420-4190. The Interest Income is currently mapped to SAP account 10419000, as of 10/1/2022.

Issue

FERC Form 1 and the filing schedule 1604.01(a)(1)(a) reflects a total for Interest Income of:

Account	Description	Balance
47030010419000	Interest Income	$ (259,745.02)
47050010419000	Rental Income	$ (22,217.35)
	Total Interest Income	$ (281,962.37)

The SAP account 10419000, Interest Income, erroneously included a total of $(22,217.35) in monthly income, from October through December, for two of the Company's tower rental agreements.

The $(22,217.35) was not included in the filing schedule RR-2.3 for income associated with rent, account 10454000

Recommendation

The Company should update the Revenue Requirement filing schedules to include the Rental Income $(22,217.35).

The Company should update the accounting to ensure that Rental Income is posted to the correct SAP account, 10454000, Elec Rev Other.

Company Response

Liberty concurs and will incorporate the recommended adjustments in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company adjusting the filing.

Audit Issue #12
Revenue

Background

Audit reviewed the filing schedules to ensure that the revenue included all accounts.

Audit Issue

Based on a review of the FERC Form 1, and the general ledger accounts that support the revenue, the revenue in the filing is understated by $(383,135). Audit noted account OCOA/400330 Electric Revenue-Other, 10407300 $(383,135) on the Depreciation and Amortization Revenue Requirement schedule RR-2.12, line 8. The Company did proform it out of the Depreciation and Amortization schedule, but did not proform it into RR-2, RR-2.2, or RR-2.3.

Audit Recommendation

Audit recommends that the Revenue schedules in the filing be updated to include the additional $(383,135).

Company Response

Liberty disagrees on the basis that an update such as the one proposed by Audit would have no effect on the rate case. Specifically, the pro forma adjustments made by the Company on RR-2.3 ensure that the test year pro forma revenue reconciles to forecasted normalized revenues.

Audit Comment

Audit disagrees. The filing begins with the actual revenues during the test year.

Audit Issue #13
Payroll General Ledger

Background

Audit reviewed the payroll registers for both weekly and bi-weekly paid employees for the final pay period of 2022.

Audit Issue

Prior to the switch from Great Plains to SAP, GSE used an Opex Capex report to reconcile the payroll to the general ledger. While on-site to review the confidential payroll registers, Audit requested the Opex Capex report for December 2022. It was noted that the Opex Capex report is no longer available since moving to SAP. It was also noted that a replacement report has not yet been established.

Audit requested the reconciliation process and the report used to reconcile the payroll to the general ledger. The response provided the process and a reconciliation of the timesheet report to the payroll register. The reconciliation process did not include reconciling the payroll registers to the general ledger

Audit Recommendation

As reconciling the general ledger is an important step in providing accurate account details, Audit recommends that GSE prioritize a replacement report to the Opex Capex report.

Company Response

The recommended report was already developed and was provided in the Company's response to DOE 4-16(c) on September 8, 2023.

Payroll is reconciled to the general ledger at each pay date.

Audit Comment

Audit reviewed the Company's response to DOE 4-16(c). The response noted to *"refer to Attachment 23-039 DOE 4-16.c for regular and overtime labor for the time periods requested broken down by capital, expense, and other"*.

The attachment shows the monthly labor total broken down by Capital Labor, O&M Labor, and Other Balance Sheet (non-plant) Labor. The total for the year was noted to be $11,254,980.

The attachment does not contain any general ledger detail. Audit therefore reiterates this Audit Issue and recommendation as the Attachment 23-039 DOE 4-16.c does not contain the pertinent information needed to reconcile the payroll to the general ledger.

Audit Issue #14
Temporary Employees

Background

Audit requested a listing of temporary employment agencies used during the test year. Audit also requested the total expensed for the year and the general ledger accounts to which the expenses were booked.

Audit Issue

GSE's response noted that $456,528.50 was paid to Balance Professionals in 2022. They also noted that the expenses were booked to GL account 500300.

In SAP, account 500300 references that the expense is an outside service. In the Company's response they failed to include the regulatory account where the expenses were booked.

Audit reviewed the detailed GP and SAP GL and noted a total of $404,502 in expenses for Balance Professionals.

Audit was unable to verify the expense amount GSE noted, $456,528.50.

Audit Recommendation

The Company needs to provide the specific and complete general ledger detail supporting their referenced $456,528.50.

Company Response

The Company provided information for the general ledger detail for test year payments to Balance Professionals. The total expense amount has been revised to $210,344.08. The amount of $456,528.50 previously provided in response to an earlier question, was overstated as it reported the total amount paid to Balance Professionals, including payments for the service company (Company Code 8810 / 3070) and Energy North (Company Code 8840 / 3072).

Audit Comment

Audit reviewed the additional documentation provided for the test year payments to Balance Professionals. The information provided the Balance Professional general ledger activity for both Great Plains and SAP. The documentation showed the total paid to Balance Professionals in Great Plains was $111,032.77. Audit was able to verify that amount to the detail General Ledger Audit had previously received without exception.

The additional documentation provided also showed a total of $99,311.31 being paid to Balance Professionals in the SAP system. The GL detail provided does match the $99,311.31. total but does not include the vendor information to verify it was for Balance Professionals. However, only $30,393.17 could literally be identified a payments to Balance Professionals, through use of a previously provided general ledger which included vendor information.

Audit Issue #15
End of Year Accruals

Background

Audit requested the journal entries and supporting detail for the payroll accruals booked at the end of the year.

Audit Issue

The Company provided the journal entries for the payroll and vacation accruals for Company 3070, Liberty NH. The detail did not provide the allocation to GSE or the payroll support for the accruals.

Audit was unable to verify the year end payroll accruals to the general ledger detail for GSE.

Audit Recommendation

As the year end accruals are based on actual time worked, the supporting documentation should be readily available upon request.

Company Response

The Company provided additional supporting documentation for vacation accruals and payroll accruals, respectively.

Audit Comment

Audit reviewed the additional documentation provided in response to this issue. The additional support for the vacation accrual provided the total charged to each regulatory GL account. Audit was able to verify the amount of $50,394.94 to the detail GL, previously obtained, without exception.

The additional support provided for the payroll accruals also shows the amount accrued to each regulatory account. The December payroll accrual includes adjustments from October and November as the settlement process was initially set up incorrectly. However, these entries were verified to the detail GL without exception.

In prior rate case audits, GSE was able to provide the payroll support to verify the accrual amounts are correct. This detail that was previously provided included employees names, hours worked, pay rate, and unused vacation hours. With SAP, Accounting no longer has access to the level of payroll detail to tie the accrual amounts back to specific employees and pay amounts.

Although Audit was able to tie the additional documentation provided in response to this audit issue back to the General Leger, Audit is unable to determine if the accrual amounts are accurate due to the inability to provide supporting documentation to the amounts.

Audit Issue #16
Payroll Taxes

Background

Audit reviewed the $642,935 of payroll taxes that were included in the filing.

Audit Issue

During Audit's review of the payroll taxes, it was noted that following the conversion to SAP there were no payroll tax expenses booked to FERC account 408 for October, November or December.

The Company provided the journal entry detail booking the payroll taxes to Company 3071 from Company 3070. The journal entry showed that the payroll taxes were being booked to FERC account 920 and not 408.

Audit Recommendation

Audit recommends the Company update the filing moving the payroll taxes from FERC account 920 to 408. Going forward all payroll taxes should be booked to the appropriate 408 account.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding and make any necessary correcting entries. Going forward, the Company will book payroll taxes to the appropriate account.

Audit Comment

Audit concurs with the Company's response

Audit Issue #17
Transactions past 9/30/2022 in SAP General Ledger

Background

Transactions in the Great Plains ledger were supposed to roll forward to the SAP ledger as of 9/30/2022.

Issue

After the conversion from Great Plains to SAP, SAP Account 50500010580000 - Operation Supervision and Engineering did not show any further transactions and Audit is unsure if this is due to the mapping issue identified in this report as Audit Issue #1, or if the account truly had no further activity in it after 9/30/22.

Recommendation

The Company should review the account in question and determine if any activity after 9/30/2022 should have been posted to account 50500010580000. If mapping issues are identified, the filing schedules should be updated.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

The transactions previously charged to account 505000-10580000 for the period January through September 2022 were Fleet allocations. Fleet charges totaling $22,141 for the period October through December 2022 were reported in account 804050-10999999 which were subsequently reclassed to account 10920000. The Company will update the filing schedules to reflect the adjustment to account 10580000.

Audit Comment

Audit concurs.

Audit Issue #18
Expenses to Be Considered Non-recurring.

Background

Audit reviewed the account activity in several expense accounts, and sample tested certain expense entries.

Issue

Based on the documentation provided and the activity in the account, the following entries should be considered non-recurring:

SAP/GP Ledger	Account Number	Account Name	Amount	Description
SAP	50030010593000	Maintenance of Overhead Lines	$ 1,200.00	Storm 2113 Disallowed Costs
SAP	50030010593000	Maintenance of Overhead Lines	$ 211.98	Storm 2102 Disallowed Costs
GP	8830-2-9851-56-5210-5932	Maint of Overhead Lines - Veg Mgmt	$ 6,260.63	Disallowed Trans of Chrgs Storm 2102 to 2103
			$ 7,672.61	

Audit initially questioned several rental car expenses, and was told the costs were incurred due to the COVID-19 virus. Because the COVID-19 pandemic has subsided, Audit recommends that all of the charges below that posted to account -9302 be considered non-recurring. According to the Company some of the costs were outside of the test year, although they did not indicate specifically which ones. Overall COVID-19 expenditures were $404,409.54.

COVID Job	Total Charges	GP GL Account	Total Charges
8830-9810-COVID19	$ 3,503.66	8830-2-9810-69-5615-9302	$ 3,503.66
8830-9815-COVID19	$ 59,013.76	8830-2-9815-69-5615-9302	$ 59,013.76
8830-9825-COVID19	$ 156,245.46	8830-2-9825-69-5615-9302	$ 156,245.46
8830-9830-COVID19	$ 77.70	8830-2-9830-69-5615-9302	$ 77.70
8830-9835-COVID19	$ 2,030.75	8830-2-9835-69-5615-9302	$ 2,030.75
8830-9840-COVID19	$ 25.91	8830-2-9840-69-5615-9302	$ 25.91
8830-9853-COVID19	$ 13,225.78	8830-2-9853-69-5615-9302	$ 13,225.78
8830-9860-COVID19	$ 214.00	8830-2-9860-69-5615-9302	$ 214.00
8830-9865-COVID19	$ 13,323.06	8830-2-9865-69-5615-9302	$ 13,323.06
8830-9851-COVID19	$ 156,749.46	8830-2-9851-69-5010-9200	$ 34,201.82
		8830-2-9851-69-5615-9302	$ 17,923.18
		8830-2-9852-69-5615-9302	$ 104,624.46
Grand Total	$ 404,409.54	Grand Total	$ 404,409.54

Recommendation

Audit recommends that for the rate case consideration, the expenses above should be considered as non-recurring and removed from the filing.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding. Only $110,660.53 of the $404,409.54 was recorded during the test year (i.e., 2022).

Audit Comment

Audit concurs with the Company response.

Audit Issue #19
Expenses Outside of the Test Year

Background

FERC Account 593 (Maintenance of Overhead Lines): The Company entered into a contract with Asplundh Tree Expert, LLC for $551,986.77 in 2021. The company expensed $218,661.81 in 2021 and recorded a debit accrual entry totaling $281,017.96.

FERC Account 598 (Maintenance of Miscellaneous Distribution Plant): The Company included an accrual for $11,779.30 dated 9/15/2022 for 10 invoices from Bashlin Industries, Inc. posted to GP account 8830-2-9851-56-5210-5980.

Issue

FERC Account 593: The Company recorded a credit accrual in 2022 totaling $281,017.96 and paid $333,319.96 in expenses leaving $52,302 in 2021 expenses paid recorded in 2022. It is unclear why the Company did not record an accrual entry in 2021 for the remainder of the unpaid contract for $333,319.96.

FERC Account 598:The Company stated that all "*All inventory was received in at once on receipt RCT00062466 in GP prior to SAP cutover*" indicating all materials were received in the test year of 2022. Invoice INV 323443 totaling $465.10 was dated 3/28/2023 and had a "shipped date" of 3/28/2023 indicating items were shipped outside of the test year.

Recommendation

The Company should make any adjustments to filing schedules removing the $52,302 and the $465.10 from the filing.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs.

Audit Issue #20
Automatic Template for Calculations

Background

Audit reviewed the SAP account 912 balances that sum to the reported $(10,826.58) and requested clarification of the credit balance.

Issue

The Company identified that the upon migration from the Great Plains system to the SAP system the automatic template used to calculate capital costs had not processed correctly for October and November 2022 leading to significant reclassification entries to be made.

Account 912 Demonstrating and Selling Expenses ($10,827) is the sum of the following SAP general ledger accounts and was verified to RR-2 of the filing and FERC Form 1:

50000010912000	Salaries and Wages	$ 12,608.86
50005010912000	AllocCorp Lbr Leg	$ (4,283.25)
50010010912000	Vacation & Other TO	$ 3,369.69
50150010912000	Advertising Expenses	$ 882.12
50400010912000	AllocCorp Cap Leg	$ 318.00
50500010912000	Other Operating Exp	$(18,567.55)
50510010912000	Cost Alloc to Cap	$(22,392.47)
70200010912000	BS Lbr Offset	$ (3,222.09)
80000010912000	Lbr Alloc	$ 26,080.16
80300010912000	Assess Lbr	$(10,133.92)
80308510912000	Assess Travel	$ 230.62
85300010912000	Assess Lbr-Intrc	$ 4,560.92
85311010912000	As OH BenIntrc	$ (277.67)
		$(10,826.58)

The GP general ledger only consisted of 2 invoices from Jill M. Fitzpatrick totaling $882.12. The SAP general ledger however consisted of numerous credit entries labeled as marketing, payroll interest corrections, missed A&G assessments and true ups resulting in a large credit balance at the end of 2022. Audit questioned the Company as to the reason why there were so many entries as in previous years entries have always consisted of small vendor invoices and resulted in an overall -7318% decrease from calendar year 2021. The Company responded with the following:

The credit balance in FERC account 912 is mainly due to a correcting journal entry that was recorded in December 2022. Upon migration to SAP, the systems support team identified that the automatic template used to calculate capital costs had not processed correctly for October and November 2022, hence a reclass entry was done to correct the missed costs.

Audit is unsure if the automatic template has been corrected or if other template mitigations were processed correctly.

Recommendation

The Company should confirm that other template migrations were not affected in the GP to SAP transition and disclose if this template has been corrected for future use.

Company Response

Liberty confirms.

Audit Comment

Audit understands the Company response to be that other template migrations were not affected. It is unclear if the automatic template that resulted in this Audit Issue has been corrected.

Audit Issue #21
Expense variance

Background

The Company expensed 2 invoices from PC Connection totaling $32,374.26. The allocated portion of these invoices for GSE was $9,712.28.

Issue

The Company recorded $9,950.53 to GSE GP account 8830-2-9800-69-5130-9210 (Office Supplies & Expenses) resulting in a $238.25 overage in expenses.

Recommendation

The Company should make any adjustments to filing schedules removing the $238.25 from the filing and ensure expenses are recorded correctly.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company response.

Audit Issue #22
Charge posted to expense account rather than deferral account

Background

The Company recorded 2 invoices totaling $50,895.20 to SAP account 50254010923000. Upon submitting supporting documentation for the charges, the Company advised the following for both invoices " *Invoice was transferred to Battery Storage deferral account*".

Issue

The Company recorded 2 charges to expense account 923 when they should have been posted to a deferral account.

Recommendation

The Company should make any adjustments to the filing schedules removing the $50,895.20 from account 923 and posting them to the correct deferral account.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs.

Audit Issue #23
Regulatory Expenses vs. Political Contributions

Background

The general ledger account activity for January through September 2022 was noted in account 8830-2-9830-69-5610-9280, Regulatory Commission Expense. At conversion, the activity was rolled into SAP account 3071-50506010928000 Reg Commissions Expense.

Issue

Revenue Requirement schedule RR-2.10 and FERC Form 1 reflect a total Regulatory Commission expense of $643,455. The PUC fiscal year assessments for 2022 (July 2021 through June 2022) and 2023 (July 2022 through June 2023) summed to $651,654, $8,199 higher than the FERC Form 1 and the RR-2.10. Audit verified the difference to the net of two specific journal entries:

February 28, 2022 entry in the GP 928 activity	$ 1,800.00
December 31, 2022 reclass PUC Assess to Default Srv	$(10,000.00)

The $1,800 membership investment was part of a total Business and Industry Association membership fee of $2,400 and was incorrectly posted to the Regulatory account.

10928000 Regulatory Commission Expenses -strategic plan	$1,800	
8830-2-9868-69-7450-4264 Political Contributions	$ 600	
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$1,800
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$ 600

Recommendation

Audit recommends that the filing schedule RR-2.10 be reduced by $1,800 for account 928, and reflected within the filing schedule associated with Dues and Membership. Audit understands this has no impact on the income statement.

Company Response

The $1,800 membership dues portion was incorrectly charged to regulatory commission expenses and should have been charged to dues and membership. The Company will make this adjustment in the next update of the revenue requirement model in this proceeding.

Audit Comment

Audit concurs.

Audit Issue #24
Filing vs. Response to Staff Data Request

Background

At year-end, the SAP "Rental" expense accounts were:

3071-50130010931000 **Meals & Ent**	$132,786.40	RR-2.10
3071-50300010931000 Rental Expense	$ 71,284.90	RR-2.10, RR-3.8
3071-50304010931000 Lease Exp	$ 1,397.50	RR-2.10
3071-50500010931000 Other Operating Exp	$ -0-	
Rent Expense at year-end 12/31/2022	**$205,468.80**	

The total was verified to the FERC Form 1 and filing schedule RR-3.8

Audit Issue

In response to DOE Staff Data Request #4-48, Liberty indicated that the original filing schedule RR-3.8 did not include all of the Rental Expenses. That response showed that RR-3.8 should have reflected:

Intercompany Rental-Londonderry building annual lease	$ 59,236
Intercompany Rental-Concord Training Center annual lease	$123,893
Facility Lease E-Point for 130 Main St. Salem	$ 26,125
Facility Lease 116 N Main St. Concord	$ 854
Filing per DOE DR 4-48	**$210,108**

Audit Recommendation

It is unclear where the difference between the original filing and the updated Data Response was posted, or where within the filing it may have been originally identified.

Company Response

The Company provided additional support containing a summary of the various entries and a reconciliation to the **$213,848**.

As discussed in the Company's response to OCA 3-66, the 2022 lease expense was $213,848.30. The Company identified a correction to rental expenses included in RR-3.8 along with a small adjustment to the amount reported in DOE 4-48. The $210,108, as included in DOE 4-48, inadvertently included $4,916.50 of charges for maintenance of plant and was missing $8,657.24 relating to the Company's Salem walk-in center ($210,108 – 4,916.50 + 8,657.24 = 213,848.74).

Audit Comment

Audit reviewed the additional support, which showed:

2022	Rent Expense	SAP Reg Acct 10931000	Difference
Jan	11,764.46	11,764.46	-
Feb	17,714.62	17,714.62	-
Mar	17,714.62	17,714.62	-
Apr	17,714.62	17,714.62	-
May	17,359.79	17,359.79	-
Jun	12,423.79	12,423.79	-
Jul	22,295.79	22,295.79	-
Aug	17,359.79	17,359.79	-
Sep	17,359.79	17,359.79	-
Oct	15,142.12	10,206.12	4,936.00
Nov	24,763.51	19,922.51	4,841.00
Dec	22,235.40	23,632.90	(1,397.50)
Grand Total	213,848.30	205,468.80	8,379.50

Exclude	(1,397.50)	Legal Invoice s/b 502400-10923000
Exclude	(95.00)	Equipment Rental s/b 500500-10586000
Include	9,872.00	Londonderry lease 2 months (recorded to 503000-10921000 in error)
Revised Total	213,848.30	
OCA 3-66 Total	213,848.30	
no difference	-	

Based on the information provided, it does not appear that the income statement was impacted overall. Audit appreciates that the Company researched the inaccurate accounting and the statement that the corrections will be included in an updated filing.

Audit Issue #25
Corporate Allocations

Background

Due to the corporate structure of Liberty, monthly expense allocations are booked to the general ledger of GSE for corporate expenses.

Audit Issue

Audit requested the direct and indirect corporate billings for November 2022. The Company provided supporting documentation for eight corporate billings.

Audit reviewed the supporting documentation for the corporate billings in detail. For all eight billings, Audit was unable to verify the expense amounts to the GSE general ledger.

For the indirect billing, in which the expenses are allocate to GSE using the 4 Factor Percentage, Audit was unable to verify the correct expense amount was allocated to GSE.

Audit Recommendation

Audit recommends the Company verify the expense billing allocation amounts and the general ledger account to which the expenses are booked.

Company Response

The Company provided additional support containing the specific GL accounts where the allocated expenses are recorded on the GSE books.

Audit Comment

Audit reviewed the additional support provided in response to this audit issue and notes that a total of $628,867.06 was billed to GSE through Corporate Billings in November 2022. Of that total, only $15,818.78, or 2.5% of the total booked to GSE was verified to the detail GL.

GSE provided the regulatory GL account and offsetting account for the Direct Billing Manual LUC and Direct Billing Manual LABS journal entries. These billings only had one line of detail each. Audit verified this total of $4,785 to the SAP GL detail without exception.

The remaining six Corporate Billings reviewed had multiple lines that summed to the total charged. For these charges, GSE did not provided the regulatory account in the additional support provided. Rather, GSE provided a total per “natural” account (corporate/GAAP) for each invoice. As each natural account is associated to several regulatory accounts, Audit was only able to verify $11,033 out of $624,082 charged to GSE based on the information provided.

Audit Issue #26
Property Tax Filing Schedule RR-3.6
Adjustments to make per the June 8, 2023 PTAM Audit Report

Background

The Company reflected $4,883,044 on the filing schedule RR-3.6

Issue

On June 8, 2023 the DE 23-037 property tax PTAM Audit report was issued. The Audit report reviewed both issuances of the 2022 municipal property tax bills that summed to $4,816,970. The report identified ($28,184) in municipal property tax adjustments resulting in $4,788,786 in 2022 municipal property tax expenses. The adjustments related to the $227 Town of Charlestown for including the State Education Tax, $28,194 adjustments to the Town of Walpole related to the reported filing vs the 2022 actual amounts on the property tax bill, and a $237 allowance based on a difference between the filing and actual tax obligation due to a lower parcel assessment in Windham.

Based on a review of the RR-3.6 property tax filing schedule the Company will need to make the same ($28,184) adjustment plus an additional adjustment of ($66,074) related to Lebanon Parcels 157/1 and 157/2 that the Audit report indicates related to assets that were not placed into service and not considered used and useful. The net adjustments to the 2022 municipal installment payments are now $4,788,786 as was presented in the Audit report.

Recommendation

The Company should adjust filing schedule RR-3.6 to reflect $4,788,786 in 2022 municipal property tax expenses based on the DE 23-037 PTAM report issued on June 8, 2023.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company Response.

Audit Issue #26
Artwork

Background

Within the prior audit report, in docket DE 19-064, Audit Issue #4 identified $5,265 in artwork that was included in Plant in Service, in account #398, Miscellaneous Equipment. Audit had recommended that the amount be excluded from Plant in Service since it is not necessary for the safe and reliable provision of electrical service. The Company disagreed.

Issue

The $5,265 artwork was noted to have been part of project 8830-CNN026. In the prior report, Audit recommended that the artwork is not necessary for the provision of electrical service, and it should be expensed below the line, rather than included in account #398 and purchased with ratepayer funds.

The Company responded to the previous issue:

"*The Company disagrees with this recommendation. The artwork at issue is nothing extravagant nor excessive and consists of a number of framed prints that are on walls throughout the Londonderry facility. Without the artwork the walls would be bare except for paint. The Londonderry headquarters building is by no means opulent, and the low cost artwork provides a small measure of color to marginally enhance the workplace. The Company notes that account #398 is used for items that are not specifically provided for in other accounts, so inexpensive prints should not be considered disallowable. The Audit Staff cites to no rules or rulings in support of the recommendation. Rather, it appears this recommendation is arbitrary and, with no cited basis for the recommendation, appears solely based on the subjective opinion of an auditor. Thus, it is difficult from a Company perspective to agree to recommendations of a subjective nature when no authoritative guidance is cited.*

In addition, using the 3.85% depreciation rate results in an annual expense of $202.70. This is quite immaterial and further demonstrates that this recommendation is unwarranted."

Recommendation

Audit recommends that the Company and the Department of Energy Staff determine the prudence and appropriateness of including this cost as a component of Plant in Service.

Company Response

The audit issue identified appears to be from a prior rate case in which all issues were resolved through a global settlement agreement. There were no instances of this issue arising in this rate case, therefore the Company does not have any issues to respond to related to this audit issue.

Audit Comment

While Audit understands the Company comment, the issue is restated. The ratepayers should not pay for artwork. This was reviewed to ensure that the sample of plant additions tested during the last rate case, for which issues were identified, were addressed. Audit and the Department of Energy cannot review 100% of Plant in Service.

Audit Issue #28
FERC Form 1 does not Agree with the Filing

Background

Account #922 Administrative Expenses Transferred-Credit shows $(8,002,460) per the FERC Form 1 and the SAP year-end account balances.

Account #926 Employee Pensions and Benefits shows $3,697,502 per the FERC Form 1 and SAP year-end account balances.

Issue

FERC Form 1 Account 922 does not agree with the filing RR-2.10 which reflects $(8,501,412), a variance of $498,952. The Company indicated that the variance was "*due to the reversal of an entry to correct an unsettled WBS charge impacting regulatory net income.*"

FERC Form 1 Account 926 does not agree with the filing schedule RR-2.10, which sums to $4,053,502, or $356,000 higher than the FERC Form 1. In response to a request for clarification of the variances, the Company noted that the variance "*is due to a correction for pre-cap meter overheads which were double booked.*"

The Company further noted that "*The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement.*"

Audit informed the Department of Energy staff to this and Data Request #11-14 was issued on October 5, 2023.

Recommendation

The Company should ensure that its presentation of the FERC Form 1 reflects true, actual account details.

Both of these accounts were also impacted by mismapping. See **Audit Issue #1**.

Company Response

As noted in the Audit Issue text above, the Company did provide a response to Department of Energy in DOE 11-14 identifying the complete list of entries identified after the December 31, 2022, financial records were closed that were not reflected in the FERC Form 1 but were presented correctly in the Company's revenue requirement filing in this proceeding. The Company addresses the financial statements in the response to Audit Issue #1.

Audit Comment

Below is the response provided to data request DoE 11-14:

Attachment DE 23-039 DOE 11-14

1) Capitalize 85% of physical inventory write off recorded

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10921000	M&C-Inventory Diff	10920000	500495	(687,051)
1	10107000	CWIP	10107000	150110	687,051

Physical inventory adjustment was recorded in December 2022. The system did not capture the amount for capitalization. This was identified after year end as a manual adjustment needed in the preparation of the revenue requirement.

2) Correct over-accrual of capital invoices that were paid in 2022

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
1	10107000	CWIP	10107000	150110	(857,308)
2	10242000	Misc Accrued Liab		210300	857,308

Following the year end close, it was identified that certain capital accruals were accrued that had already been paid in the year. This was corrected manually in preparation of the revenue requirement.

3) Correct pre cap meter overheads double-booked

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10926000	Benefits	10926000	500150	356,000
1	10107000	CWIP	10107000	150110	(356,000)

Overheads on pre capitalized meters were inadvertently recorded twice in 2022. This was identified following the year end close and was manually corrected in preparation of the revenue requirement.

4) Entry to correct regulatory net income

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
7	10182300	WBS ST Services	10182300	702xxx	(498,952)
1	10182300	Regulatory asset	10182300	171500	498,952

The SAP system is set up in a way that GAAP and regulatory (FERC) accounts can be recorded differently for each journal entry to allow for GAAP to FERC accounting differences. In reviewing the regulatory results, it was determined that certain regulatory entries were recorded incorrectly. This entry was manually corrected in preparation of the revenue requirement to align with the expectation that the Company would not have material differences between GAAP and FERC results.

5) Correct regulatory account settlements

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10920000	Other Operating Exp	10920000	505000	(18,143)
1	10107000	CWIP	10107000	150110	18,143

Similar to entry (4), as part of the Company's review of the regulatory results, the Company identified that certain settlements did not follow the correct accounting for regulatory reporting purposes. This was corrected in preparation of the revenue requirement.

Summary:	Dr / (Cr)
Net P&L Impact	(848,145)
Net CWIP Impact	(508,114)
Accruals Impact	857,308
Regulatory Asset Impact	498,952

Audit reinforces the stated issue, that the FERC Form 1 does not reflect the actual account balances in the reported accounts. It is understood that the Company and the External Auditors did not feel the need to ensure those reported accounts aligned with the SAP, as that would impact corporate level financial reporting. Refer to Audit Issue #1.

III. Planning and Budgeting

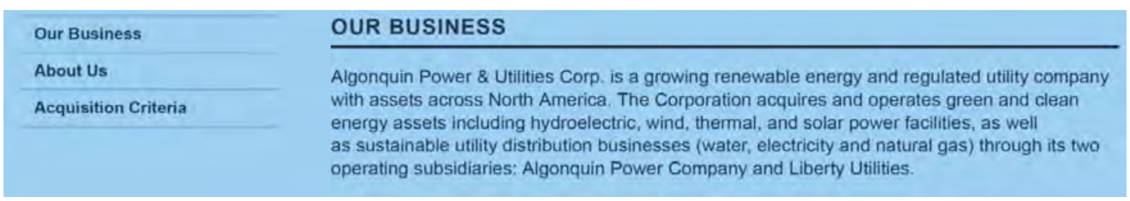
A. Background

1. APUC's Overarching Strategy

APUC's business model focuses on growth, has depended on high rates of growth since its 1997 inception, and appears destined to continue to depend on acquisitions of small utility distribution and generation operations across the United States and Canada.

The parent's web-site describes this strategy clearly, focusing very strongly on APUC's process of "becoming." The following statement, with emphasis added, introduces searchers to the holding company's self-description:

> *Algonquin Power & Utilities Corp. is a* ***growing*** *renewable energy and regulated utility company with* ***assets across North America****. The Corporation* ***actively invests*** *in hydroelectric, wind, thermal and solar power facilities, and sustainable utility distribution businesses (water, electricity and natural gas).*
> *Algonquin Power & Utilities Corp. is focused on delivering reliable earnings, cash flow and dividend growth through* ***strategic acquisitions*** *and operational excellence. The Corporation is a member of the S&P/TSX Composite Index and trades on the Toronto Stock Exchange under the symbol AQN.*
> *The Corporation is recognized for* ***developing and acquiring*** *long lived sustainable assets that are built for the long term, and has grown to over 66 power generation facilities and utilities in Canada and the United States. The company has approximately 1,450 skilled and motivated employees contributing to the success and growth of the business.*



The strength of focus on acquisitions shows in the three "buttons" on the web page describing the business: "Our Business," "About Us," and, notably, "Acquisition Criteria." The last offers, to say the least, a rare point of emphasis in a utility holding company's succinct message to stakeholders describing its business.

The two New Hampshire utilities that APUC owns are fairly small ones. That status particularly means that operation in the APUC family presents both opportunity and risk. Opportunity comes from the leverage (size) that other family members contribute to producing. That leverage should enable investment in organizations, systems, tools, and people that two, small, stand-alone companies simply could not justify on their own.

Risk arises from two principal sources. The first arises from the great financial needs that growth through acquisition requires. While striving to retain the financial ability to make acquisitions, which requires flexibility to act when opportunities arise, parent company leadership must ensure that sufficient focus remains on meeting utility capital and operating needs. Second, from the perspective of New Hampshire interests (or those of any other state, for that matter), retaining top-level focus on two utility distribution businesses operating among many small, far-flung, trans-national businesses takes structure and focus. That the parent's operations split largely between generation and distribution sectors (moreover with relatively few individual operations combining them materially) complicates things. That the parent's roots lie in developing generation also complicates matters. Moreover, and perhaps most significantly, its culture, physical location, and corporate-level resources are not, at least on the surface, well grounded in U.S. energy distribution utility experience. For example, all of its distribution utilities operate within the United States. However, all of its corporate support structure and personnel operate from Ontario.

Factors like these that lie on the surface of the APUC strategy and structure make it appropriate to examine the degree to which APUC can move and has moved from an "acquisition" to and "operation" mentality, or, more precisely, given the continued focus on acquisition, how well it can support the maturation of an operations emphasis within the context of the acquisition and growth philosophy that has defined it since its origins.

Certainly, there is acknowledgement of and commitment to operational excellence in public statements and in what management told us during our field work. Just as certainly, there have been problems in integrating New Hampshire operations into the Liberty Utilities family. As our examinations in the areas addressed by the other chapters of this report demonstrate, significant improvement opportunities remain. It also appears that they may have to be captured at the same time that APUC digests yet another acquisition. Its pending acquisition of Empire District Electric would bring another 217,000 customers (in four states) to an existing base of 560,000 (a nearly 40 percent increase) across in 11 states. In microcosm, this pending acquisition captures the tension between APUC's priority on "becoming" (through growth) and its need for a focus on "being" (establishing a strong and sustainable operations model and focus).

2. U.S. Distribution Utility Territorial Breadth

The map shows the vast dispersion of Liberty Utilities operations. All distribution utilities operate in the U.S. The generation business (operated by APUC subsidiary Algonquin Power Company) owns all or portions of 33 generating facilities (1,100 megawatts). The 24 Canadian generators extend from the Maritimes to Alberta in Canada and the nine in the U.S. extend from three in New England to one in California. While predominantly Canadian, they too exhibit an extremely large territorial dispersion.

As determined by customer connections, natural gas distribution comprises the largest Liberty Utilities segment, with six U.S. operators providing service to some 293,000 customer connections. New Hampshire represents 30 percent of them. The second largest segment, water distribution and wastewater treatment includes 26 operations serving over 175,000 customer connections. Electricity, the smallest segment by this measure includes two operations serving over 92,000 customer connections. New Hampshire represents close to half of them. APUC has a very short history in the electric utility distribution business. Its first entry came with acquisition of a 47,000 Lake Tahoe area electric company. At the time utility operations were limited to 70,000 water and waste water treatment customers.

The dispersion of both the utility and generation segments heightens the challenges of planning for optimization of operations and in developing budgets and managing expenditures to execute those plans.

The company is also pursuing growth in natural gas with pipelines delivering shale natural gas to markets.

Liberty Utilities, and in turn LU-NH, face significant operational performance challenges, while also meeting the aggressive financial growth expectations of its holding company parent. Meeting these challenges requires well designed and effectively executed budgeting and cost management. Budgeting and cost management begin with board of directors and senior executive leadership, which must articulate a consistent vision, establish a clear mission for meeting public service responsibilities, define objectives and goals, set priorities, develop strategic plans, allocate resources, develop financing plans, and implement and measure performance against these plans. The challenge is not simply to define management's vision and strategic plans in a comprehensive and specific way, but to bring them to fruition in a far-flung organization and in a way that responds generally to public service responsibilities and specifically to the requirements and expectations of regulators and stakeholders in New Hampshire.

The corporate processes for budgeting of capital expenditures and of operating expenses must be effective for good planning and strategies execution. The LU-NH processes must effectively provide for gas and electric system reliability through investments and operations and maintenance activities, while maintaining corporate financial health. Specific plans for funding utility capital requirements and allocation of capital are ultimately the responsibility of the holding company, whose leadership should play a strong planning and budgeting role, and recognize the need to give appropriate priority to utility needs when allocating resources.

Good practice builds O&M budgets from the bottom-up by management within each major organization. The use of activity-based budgeting has become a standard for optimizing costs, when properly applied. Once set, budgets require ongoing attention and revision where appropriate. This need has particular relevance for Liberty Utilities, which must not only sustain optimum operations at existing units, but has had to address the challenges and uncertainties of incorporating new operations in new regions on a recurring basis. Management reporting systems need to provide comprehensive, detailed monitoring and cost-control mechanisms for capital and O&M budgets at the Liberty Utilities level and at the New Hampshire levels for both electric and gas operations.

B. Findings

1. Strategic Planning

a. Vision/Mission

Liberty Utilities operates under an established vision statement that we found appropriately communicated to employees. Specifically, Liberty Utilities seeks to be:

The utility company most admired by customers, communities and investors for our people, passion and performance.

Liberty Utilities has also set a high-level mission statement that calls for it to "*Deliver stable and predictable earnings*" and that establishes the investment thesis that, "*Maximum shareholder value is created by minimizing the risk associated with earning the permitted rate of return.*"

The Company has identified a number of attributes needed to attain its mission:

- Constructive Regulatory Relationships
- Caring Customer Experience
- Standardized Processes and Technologies
- High Level of Employee Engagement
- Earnings and Cash Flow through continued rate-base investments and expansion through utility acquisitions.

Liberty Utilities stresses a series of "Organizational Values," which consist of family, community, quality, commitment, care, and efficiency.

Liberty Utilities prepared formal strategic plans in 2013 and 2014. Each covered the immediately following five-year planning period. Leadership decided that it was not necessary to prepare a 2015 version, placing priority on continuing to execute on existing initiatives.

b. Planning Process - 2013

The strategic planning processes in 2013 (and again in 2014) began with a "SWOT analysis" (strengths, weaknesses, opportunities and threats) prepared by the Liberty Utilities state presidents and the top 10 Oakville officers at the Liberty Utilities level. Leadership undertook this analysis to drive the focus of strategic planning for the next five years. Each of the four SWOT categories included ten areas for examination. We highlight some of them below:

- Strengths
  - Meeting investor expectations
  - Strong access to capital
  - Employee quality
  - Ability to execute transactions
- Weaknesses
  - Lack of business development around organic growth
  - Capital constraints
  - Key personnel stretched thin
  - Specialized knowledge stretched thin
- Opportunities

    - Accelerated infrastructure recovery
    - On-main build outs
    - Credit rating improvements
- Threats
    - Capital required exceeds Liberty Utilities' access
    - ROEs lowered
    - Access to capital markets closed.

These examples tend to underscore Liberty Utilities' strength in acquisitions, and weaknesses in delivery (thin staffing and knowledge), and a view of opportunities and threats focusing on acquisitions versus operations.

Following the SWOT analysis, the Oakville strategic planning group developed a strategic plan. The plan finally approved set forth strategies and initiatives divided into four major groups.

The first group consisted of "Driving Maximum Returns." It included three notable initiatives:

- *Enhance Regulatory Relationships*
- *Drive Local, Responsive, and Caring Customer Relations*
- *Focus on organic growth and diversified investments*.

The regulatory relationships initiative reflected recent circumstances in New Hampshire, following the transfer from National Grid. Management observed that National Grid did not have extensive contact with New Hampshire regulators. There had been long periods between rate cases. Management added a local regulatory position in New Hampshire and one in Oakville.

The customer relations initiative included planned customer surveys for all utilities in late 2014, using in-depth focus groups organized and conducted by a third-party contractor. One change resulting from this initiative was the introduction of walk-in customer service centers.

The 2013 strategic plan's second group of initiatives focused on "Acquisition Growth." The first of its two initiatives sought to introduce methods to support more discipline in assessing acquisitions and ensuring their financial contribution. The second of these acquisition-related initiatives sought to identify and seek out the "orphans" of large holding companies (*i.e.*, operations too small to attract the attention of other acquirers operating in the industry).

"Operations and Integration" formed the third group of strategic initiatives. Its first element sought to "*Evolve the Transition Management Office*" in order to strengthen the ability to integrate newly acquired operations. Two other initiatives sought to bring commonality to dispersed operations by documenting "*the 'Liberty Way'*" and managing employee cultural transitions.

The fourth area addressed "Business Infrastructure Strategies," including a series of system initiatives. These system initiatives included IT infrastructure, a new nationwide Cogsdale CIS upgrade, and improving the capability of the HRIS, or Human Resources Information System, to support talent management. The other initiatives in this area took a process focus, seeking to:

- Improve human resources processes across the board
- Formalize risk management

- Increase the focus on strategic planning.

c. 2014 Strategic Plan

The 2014 strategic plan, which remains the most recent produced, provided significantly greater detail than did the 2013 version. No change occurred in "business thesis", including the vision, mission and investment thesis and the organizational values. The plan also included for the first time a summarized five-year forecast that set forth specific financial metrics for gauging success over the planning horizon.

The 2014 strategic plan included sections treating: (a) human resource strategies; (b) operating strategies; (c) operations initiatives; (d) growth strategies; and (e) the five-year forecast. Each category is summarized in the following discussion.

i. Human resource strategies

The plan set forth a three-year roadmap of human resources "strategic objectives" that addressed (a) building a more efficient human resources organization, (b) developing talent and leadership, and (c) developing a "motivated" workforce.

The plan described a reorganization of Liberty Utilities groups that would produce two new business areas:

- Distribution and generation: all utility distribution and generation, as well as California solar operations
- Pipelines and transmission: a new organization to identify and seek investments in natural gas pipelines and electric transmission
- Energy solutions: a new group to house natural gas solutions and home services; management would terminate this group after a single year of operation
- Business development: to manage acquisition growth and to develop a Liberty planning team.

ii. Operating strategies

Operating strategies included the Liberty Way; centralization of commodity procurement; decentralization and driving toward local operations; managing regulatory relationships; managing New Hampshire regulatory reporting; filing quad-annual rate cases; and enhancing regulatory returns.

iii. Operating initiatives

The 2014 strategic plan's operating initiatives included:

- Managing cultural integration
- Improving customer billing and collections
- Continuing to improve the customer experience
- Enhancing safety, environmental, health and security
- Implementing an enterprise risk management processes
- Evolving the IT platform: including Enterprise Asset Management, the Cogsdale CIS, and the Great Plains system
- Executing growth approaches, including organic, acquisition, and new lines of business

iv. Growth Strategies

The 2014 plan enumerated and discussed at length growth strategies falling into more than 10 categories:

- Organic capital investments: dual-fuel vehicles, smart AMR, solar, specific initiatives within existing utility systems
- Customer expansions
- Tuck-in acquisitions: small utilities that can be managed by existing local operations, such as the Keene propane system
- Large acquisition growth: acting as a "disciplined buyer" to make deals accretive to earnings
- Pipelines and transmission investments: forecasting significant growth in investments
- Gas transmission opportunities: pipeline investments and acquisitions
- Electric transmission opportunities
- Natural gas-specific opportunities: LNG plants, satellite LDCs on pipelines
- Solar and home services: the plan anticipated significant investment, but business area was dropped after one year
- Solar portfolio securitization
- Rooftop solar metering
- Renewables
- Partnership opportunities (since terminated).

2. Five-Year Forecasts

a. Five-Year Forecast Process

Liberty Utilities constructs a "Five-year Forecast" as part of the strategic planning process. The forecasting process begins in March, and becomes final following presentation to and review by the parent board of directors in June or July. The Five-year Forecast provides detailed financial projections that capture expected results of the strategic plan. The key drivers of the forecast are: (a) goals for specific financial metrics determined before the supporting forecasting process begins, (b) the Liberty Utilities five-year capital expenditure plan, (c) regulatory treatments and assumptions that define cost recovery, and (d) operating expenses over the five-year horizon.

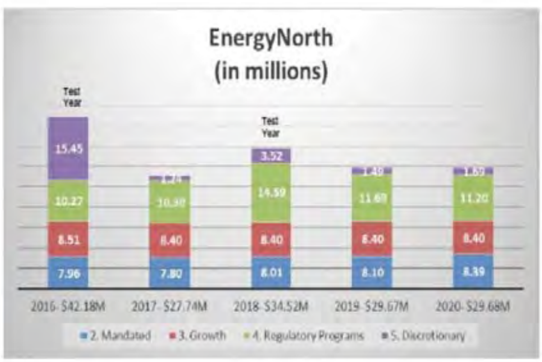
Oakville headquarters begins the process with a PowerPoint presentation in March. The presentation provides timelines, a scope of deliverables, roles and responsibilities, and key priorities. Oakville provides the templates and reports for the forecast, leaving the regions to provide their assumptions and inputs, revenue forecasts, operating expenses, and capital expenditures. The process seeks to produce a five-year forecast at a less granular level than the budget cycle for the first year, which immediately ensues.

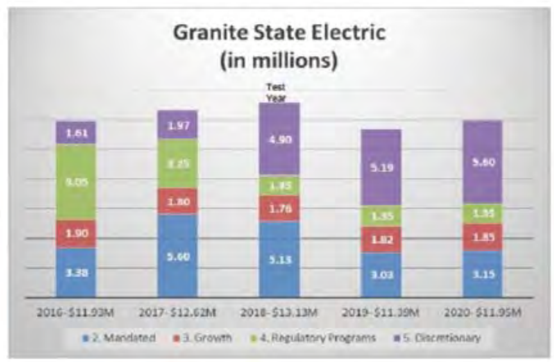
The forecasting process limits operating expenses to those authorized in rates, unless an existing rate mechanism permits adjustments between base rate cases. The process also anticipates iteration between the regions and Oakville to establish capital expenditure "envelopes." These envelopes seek to satisfy equity return levels. Oakville also produces an extension of the Five Year Forecast, covering future years six through 20. Those extended views are not used at the regional level.

New Hampshire inputs to the process begin in May, using templates of financial information for EnergyNorth and for Granite State. The New Hampshire financial staff provides operating expenses for five years. The manager of engineering constructs a forecast of capital expenditures and projects. That forecast employs a five-year rolling average of New Hampshire SAIDI and SAIFI requirements as a guide for capital forecasting. Internal New Hampshire review and analysis of this preliminary information occur in May and June. Following New Hampshire state President approval of state input, a review by the Oakville Vice President of Finance and staff takes place. The parent board of directors receives a Five-Year Forecast presentation in June or July of each year.

The next table summarizes the most recent Five-Year Forecast's capital expenditures for Energy North and Granite State.

Latest Five-Year Forecast Information for New Hampshire





The next illustration shows operating expense forecasts for New Hampshire for 2016-2020.

(The following is confidential)

[redacted]

The financial metrics for New Hampshire (shown in the illustration below) form a key product of the forecast process.

(The following is confidential)

[redacted]

b. Earlier Five-Year Forecasts

The 2013, 2014 and 2015 Five-Year Forecasts included what management terms “Baseline” and “Directional” forecasts. The 2013 Baseline forecasts included currently operated Liberty Utilities utility businesses. The Directional forecast in 2013 consolidated this baseline component with projections that considered five acquisition opportunities not in the fold, but considered to be in the business development pipeline. A key financial metric objective in the 2013 forecast was the EBITDA compound growth rate. The EBITDA compound growth rate for the Directional forecasts was almost three times that of the Baseline forecast.

The Directional forecast included an assumed acquisition of a 50,000-customer utility in each year of the forecast. The addition of an acquisition in each year caused the increase in EBITDA compound growth rate. The forecast also included assumed rate increases in New Hampshire of 24 percent for Energy North and 26 percent for Granite State, both in 2014.

Management built the 2014 five-year forecast (for 2015 through 2019) around defined target financial metrics:

- Double EBITDA in five years
- Grow EBITDA in every year
- Grow EBITDA on existing assets in every year
- Maintain a BBB credit rating.

The 2014 forecast version presented three scenarios. As in 2013, the Baseline addressed existing businesses, but added three changes: (a) smart meters, (b) a California business, and (c) an electric transmission line. The 2014 version then added a “Market” scenario; which included the Baseline plus projects that had been announced to the capital markets. The Directional scenario included the Baseline plus Market plus two hypothetical acquisitions in 2018 and 2019.

The Market and Directional scenarios included target financial metrics equal to those of the Baseline, plus an EBITDA interest coverage minimum, a total debt to capital maximum level and an FFO/Debt metric of 13 percent for utility operations. The acquisition of Park Water in 2016 and investments in LNG in 2015 through 2017 were added. Hypothetical acquisitions were assumed for 2018 and 2019. The results of the Directional forecast were to double EBITDA from 2015 to 2019, as was targeted in the process.

The 2015 forecast for 2016 - 2020 included less aggressive target financial metrics. The financial metrics evolved to the following:

- Achieve allowed ROEs for the regulated businesses
- Grow EBITDA in each year
- Grow EBITDA existing assets in each year
- Invest approximately $2 billion dollars over five years
- Maintain a BBB credit rating.

The acquisition of Empire Electric was announced by the company in February 2016. It was not included in this forecast. The Baseline scenario included the "as is" utility businesses plus Park Water, and gas and water acquisitions that were certain. The Market scenario included all announced acquisitions that are not yet implemented. In this forecast version, the Market and Baseline scenarios are the same. The Directional scenario included the Baseline plus hypothetical acquisitions in pipeline investments. The Directional forecast also assumed one larger acquisition per year of 150,000 customers in each of 2018, 2019 and 2020.

Targeted financial metrics for this forecast did not include a doubling of EBITDA, but results of the Directional forecast actually did show a doubling in five years. The forecast also included major New Hampshire capital investments for main replacements, new services for residential and commercial customers, and new gas main related to growth.

3. Budgeting

a. Overall Budgeting Processes

For both capital expenditures and operating expenses, the finance leads in each Liberty Utility region work with local operations to develop annual budgets. The finance leads (the Vice President-Finance in New Hampshire) serve as the primary points of contact with Oakville during the budget cycle.

At the New Hampshire level, the budget process begins in August under the senior manager of finance, who oversees the preparation of the operating expense budget. Oakville begins budget work in August as well under the finance executive, who provides assumptions, spending templates, an HR template, and other inputs.

All budget inputs get rolled up to region levels and compared to the first year of the Five-Year forecast. The results then go to the state presidents for initial comments. Several budget iterations may then occur between state department heads and the state president prior to the latter's approval. The proposed New Hampshire budget then goes to the Oakville finance group. Phone calls in October and November discuss various portions of the New Hampshire budget, leading to approval by Oakville finance in November. A budget presentation is prepared for the Algonquin Board of Directors, to be reviewed and approved in early December.

Oakville supplements the annual budgeting process with an "Emergent Program Process," in order to provide for the addition to the approved capital budget of new capital items as they "emerge" during the budget year. Addition of new capital projects or programs require justification through an approved business case. One emerging program secured approval in 2014, after which the number skyrocketed to 32 in 2015. The pace during 2016 (13 in the first few months) shows continuation of the 2015 experience.

b. Capital Budgeting

The New Hampshire Director of Engineering prepares the local capital expenditures budget. The manager meets with operations managers throughout the year to discuss the capital needs of the various departments, primarily focusing on smaller capital elements. The manager of engineering meets with the director of gas operations, the director of electric operations and engineering personnel to identify capital work required in the coming year.

The target metrics for SAIDI and SAIFI serve as drivers in developing the local capital budget. The manager of engineering relies on two planning engineers (one in gas and one in electric) to identify mandatory and non-mandatory capital projects.

Management prepares capital expenditure estimates for numerous "blanket" programs conducted routinely on an annual basis, determining their costs on line item basis. Year-to-year reviews are performed on both the gas and electric sides. For gas, inside meters, services, and main replacements are estimated based on a 10-year plan. The gas capital budget is about 90 percent related to compliance. Growth capital projects must have a business case with an analysis for approval. Business cases are also required for discretionary capital projects. For the 2015 budget year, business cases were performed for all line items in both the gas and electric capital budgets. Both the gas and electric businesses use the Synergy model for capital expenditures.

c. 2014 Budgeted versus Capital Actual Expenses

Variances between budgeted and actual capital expenditures in 2014 proved unusually large in magnitude and in the number and nature of their sources. The next table summarizes 2014 capital budget performance for both LU-NHG and LU-NHE. Combined, those variances reached the extreme level of 71.7 percent.

2014 LU – NH Capital Budget and Variances

Company	Budget	Actual	Variance	
			Dollars	Percent
Energy North	$26.701	$46.544	$19.843	74.7%
Granite State	$18.303	30.736	$12.433	67.9%
Total LU-NH	$45.004	$77.280	$32.276	71.7%

Dollars are in millions

Examining 2014 capital budgets line-by-line discloses a large number of significant, some extremely large, variances. Most line items showed large variances. Moreover, the underlying reasons reported by management were numerous and varied in nature. We review a number of the significant 2014 variances below. We did not try to reconcile all 2014 capital variances, but the next portions of this chapter illustrate how significant they were.

First we listed projects that experienced particularly large over-runs. The next chart shows that actual costs for these 10 projects in total ran over-budget cumulatively by about 3.5 times.

Large 2014 Capital Over-Runs

Co.	Projects	Budget	Actual	Variance	Explanation
Electric	7	$2.978	$10.076	$7.098	various
Gas	3	$0.825	$2.938	$2.113	"more complex than estimated"
Total	10	$3.803	$13.014	$9.211	

Dollars are in millions

Next we show budget to actual performance for Information Technology, Software, Equipment, and Infrastructure Capital Charged to New Hampshire. This work overran budget by 18 times.

IT 2014 Capital Charged to New Hampshire

Co.	Budget	Actual	Variance	LU Explanation
Electric	$0.302	$5.099	$4.797	"Charged to LABS Corporate"
Gas	$0.283	$5.797	$5.514	"Charged to LABS Corporate"
Total	$0.585	$10.896	$10.311	

Dollars are in millions

A "Finance Project" that had not been included in the approved budget at all drove a further, very large capital budget overrun of over $10 million. Not a "project" per se, this item represented a collection of accruals related to the budget's other line items. The next table summarizes the amounts involved.

Unbudgeted 2014 "Financial Project" Capital Costs

Co.	Budget	Actual	Variance	Explanation
Electric	0	$7.167	$7.167	"Finance Project"
Gas	0	$3.125	$3.125	
Total LU-NH	0	$10.292	$10.292	

Dollars are in millions

Three other, miscellaneous categories contributed another $12 million in capital cost variances for New Hampshire in 2014. The next table depicts these overruns, which arose from a number of notable sources. First, management explained an approximately $4.8 million variance for growth projects as "additional growth jobs identified and released in support of growth strategy." However, growth projects did not appear in approved 2014 Emergent Projects. This category reflects what should exist as a result of the process for approving projects emerging after approval of the base annual capital budget. It thus appears that board approval was not obtained for these major increases.

- A carryover of 2013 work into 2014, described as "unplanned carryover costs from 2013 to 2014" also showed unusual variances, with five projects more than doubling in cost.
- Mischarges arose under four gas projects, with the errors explained as "charges made to blanket accounts instead of other projects."

Other Sources of 2014 Capital Overruns

Co.	Budget	Actual	Variance	Explanation
Gas	$5.083	$9.874	$4.791	Growth Jobs
Electric	$2.250	$5.237	$2.987	2013 Carryover
Gas	$0.939	$5.503	$4.564	Mischarged
Total LU-NH	$8.272	$20.614	$12.342	

Dollars are in millions

While the net effect of budget variances produced large added costs for New Hampshire, large variances ran in the other direction as well. The next chart shows substantial budgeted costs not expended due to delays.

2014 Capital Under-Runs Due to Delay

Co.	Budget	Actual	Variance	Explanation
Electric	$4.399	$1.116	$(3.283)	3 projects "delayed to 2015 or later"
Gas	$3.900	$0.098	$(3.802)	4 projects: "permitting did not allow for construction initiation"
Total LU-NH	$8.299	$1.214	$(7.085)	

Dollars are in millions

d. 2015 Budgeted versus Actual Capital Expenses

Capital budget variances for 2015 improved as measured on a total basis, but still generated numerous and large variances. The total variance for LU-NHG was a nominal two percent. The LU-NHE variances, however, remained disturbingly high. Actual costs exceeded those budgeted by 15 percent. The next table summarizes overall 2015 capital budget variances at the top level.

2015 LU-NH Capital Variances

Co.	Budget	Actual	Variance	
			Dollars	Percent
Gas	$32.268	$32.875	$0.617	1.9%
Electric	$10.012	$11.522	$1.510	15.1%
Total LU-NH	$42.280	$44.397	$2.117	5.0%

Despite the lessening of the total variance from budget, a review of 2015 line items continued to show very large individual variances. We summarize some of the larger ones below.

Beginning with 2015's very large over-runs, the next table shows that they were substantial.

Large 2015 Capital Over-Runs

Co.	Projects	Budget	Actual	Variance	Explanation
Gas	7	$6.570	$12.012	$5.442	various
Electric	3	$1.372	$5.389	$4.017	"more complex than estimated"
Total	10	$7.942	$17.401	$9.459	

Dollars are in millions

The explanations provided for the over-runs were:

- Electric: work proved greater than anticipated at budget preparation
- Gas: work exceeded budgeted amounts; the budget was significantly lower than the historical average.

The "Finance Project" accounted for a very large underrun, for two primary reasons: (a) reversal of an accrual and re-allocation to individual projects, and (b) an unbudgeted project cost under-run. The next table summarizes these effects.

Large 2015 Finance Project Capital Variance

Co.	Budget	Actual	Variance	Explanation
Gas	$1.512	$(7.818)	$(9.333)	Accounting reversal
Electric	0	$(3.295)	$(3.295)	Project under-run
Total	$1.512	$(11.113)	$(12.625)	

Dollars are in millions

Unbudgeted 2015 IT capital costs charged out from Oakville caused another 2015 capital cost variance. The next table summarized the increased cost to New Hampshire of about $1.5 million.

Unbudgeted 2015 IT Costs

Co.	Budget	Actual	Variance	Explanation
Gas	$0	$0.954	$0.954	Oakville "IT and Systems allocation"
Electric	$0	$0.506	$0.506	"Corporate IT Charged out"
Total LU-NH	$0	$1.460	$1.460	

Dollars are in millions

As was true for 2014, growth projects also grew well beyond expectations, increasing New Hampshire 2015 capital costs by $7.5 million. Management explained the increase as "Additional Growth Jobs Identified and Released in Support of Growth Strategy." Again, however, 2015 Growth projects did not appear among the significant number of Emergent Projects listed as approved.

Under-Budgeted 2015 Growth Project Costs

Co.	Budget	Actual	Variance	Explanation
Gas	$7.830	$13.601	$5.771	"Growth Total less INAT Gas"
Electric	$1.350	$3.110	$1.760	"Commercial and Residential Blankets"
Total LU-NH	$9.180	$16.711	$7.531	

Dollars are in millions

Unplanned carryover of prior year budgeted costs and incorrect allocations also produced a significant variance in 2015, as they had in 2014. The next table summarizes them.

Carryover and Misallocation Driven 2015 Capital Overruns

Co.	Budget	Actual	Variance	Explanation
Gas	0	$1.706	$1.706	2 projects - "Carryover from 2014 Work"
Electric	$1.500	$4.225	$2.725	14 projects - "Carryover work from 2014"
Gas	$1.200	$1.798	$0.598	"Overhead disproportionately charged to project"
Electric	0	$0.150	$0.150	"Expense Project"
LU-NH Total	$2.700	$7.879	$5.179	

Dollars are in millions

Other significant over- and under-runs occurred in 2015 as well. The next table summarizes them.

Co.	Budget	Actual	Variance	Explanation
Gas	$0.500	$2.791	$2.291	Scope expansion added paving, main extension, engineering
Gas	$3.600	$0.109	$(3.491)	"Placeholder" for NH Gas acquisition
Electric	$5.380	$0.337	$(5.043)	"Projects Delayed Until 2016"
Gas	$12.511	$6.990	$(5.521)	"Used main replacement budget for fitting replacement"

Dollars are in millions

LU-NHE added 14 Emergent Projects during 2015, with a budgeted amount of about $415,000. We observed capital spending of about $225,000 on three of these projects. LU-NHG added 21 Emergent Projects in 2015 for a budgeted amount of about $836,000. We observed expenditures of $138,000 on three of the projects. We found spending of $596,000 on a fourth, for which only $15,000 had been requested.

e. 2016 Capital Budgets

The next table shows the 2016 capital budgets for LU-NHG and for LU-NHE. The capital budgets are prepared by line item and are grouped by five capital categories: safety, growth, mandated, regulatory programs and discretionary.

NLU-NHG 2016 Capital Budget

Priority	Project #	Project_Description	EN 2016 Capital Budget
3. Growth	8840-C18806	INAT Gas	160,000
	8840-ENI101C	Growth Customer Contribution Budget Placeholder	-200,000
	8840-ENI101	Growth New Main	1,900,000
	8840-ENI102	New Reinforcement Main for Growth	1,700,000
	8840-ENI158	Marketing & Sales	150,000
	8840-ENI161	Growth Fitting	300,000
	8840-PCN150	New Service Residential	3,500,000
	8840-PCN152	New Service Comm/Industrial	1,000,000
	8840-PCN153	Reserve for Unidentified Growth	4,750,000
3. Growth Total			**13,260,000**
2. Mandated	8840-C18750	Install Security Equipment - EN Facilities	50,000
	8840-ENI005	Inactive Service Program	160,000
	8840-ENI006	Cathodic Protection Program	750,000
	8840-ENI007	Replacement Services Random (Non Leaks)	425,000
	8840-ENI077	Replacement Services Random (Due to Leaks)	250,000
	8840-ENI100	Meter Work Project (Changes)	200,000
	8840-ENI100P	Meter Work Project (Meter Purchases)	1,300,000
	8840-ENI103	Main Replacement City/State Construction	4,500,000
	8840-ENI137	Service Replacement City/State Construction	600,000
	8840-ENI163	Service Replacement Fitting City/State Construction	60,000
	8840-REL108	LNG/LPG Capital Improvements	165,000
	8840-REL110	Valve Installation/Replacement	100,000
	8840-ENI160	Corrosion & Miscellaneous Fitting	100,000
	8840-ENI002	Meter Protection Program	50,000
2. Mandated Total			**8,710,000**
4. Regulatory Programs	8840-ENI107	Main Replacement LPP	9,000,000
	8840-ENI117	Service Replacement LPP	1,100,000
	8840-ENI162	Main Replacement Fitting LPP	180,000
4. Regulatory Programs Total			**10,280,000**
5. Discretionary	8840-C18800	Upgrade Hi Line - Concord to Tilton	12,000,000
	8840-C18801	K Meter Replacement Program	50,000
	8840-C18802	Install Main Daniel Webster Highway Merrimack	500,000
	8840-ENI164	Main Replacement Reactive	250,000
	8840-OTH-111	Dispatch and Control Center	10,000
	8840-OTH-112	Purchase Misc Capital Equipment & Tools	150,000
	8840-OTH-113	Facility Improvements & Additions - Various	300,000
	8840-OTH-114	Transportation Fleet and Equipment Purchases	1,200,000
	8840-OTH-115	IT - Software, Equipment & Infrastructure	230,000
	8840-REL105	Gas System Planning & Reliability	500,000
	8840-REL106	Gas System Control & Regulation	300,000
	8840-REL109	SCADA Capital Improvements	10,000
	8840-C18817	Install Solar Panels - EN Buildings	150,000
	8840-C18823	Pre-Code Stee Pipe Protection Program	100,000
	8840-C18824	Aldyl-A Replacement Program	50,000
5. Discretionary Total			**15,800,000**
Grand Total			**48,050,000**

Priority 1 = Safety - there are no safety priority projects in 2016

NLU-NHE 2016 Capital Budget

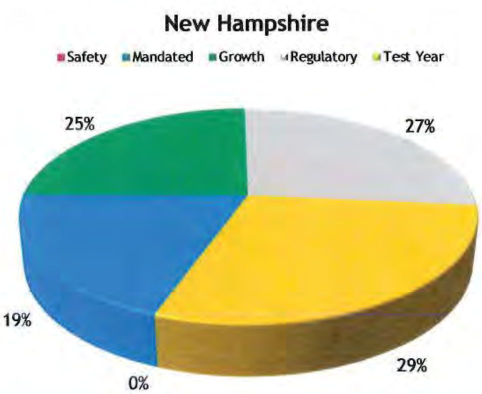
Priority	Project #	Project_Description	GSE 2016 Capital Budget
3. Growth	8830-CD0291	Sky View URD - Salem, NH	10,000
	8830-CNN010	GSE-Dist-New Bus-Resid Blanket	1,050,000
	8830-CNN011	GSE-Dist-New Bus-Comm Blanket	1,200,000
	8830-CRSRVNBC_(	Reserve for New Business Residential	50,000
	8830-CRSRVNBC_(	Reserve for New Business Commercial Unident specific & SC	100,000
3. Growth Total			**2,410,000**
2. Mandated	8830-C14646	IE-NN UG Structures and Equipment	5,000
	8830-C18750	Security Conversion GSE	25,000
	8830-C21595	01663 GS Storm Program Proj	50,000
	8830-C26263	NN D-Line Work Found by Insp.	50,000
	8830-C36433	Distribution Feeder Power Factor Correction	25,000
	8830-C36435	Lebanon Area Low Voltage Mitigation	50,000
	8830-CN4104	01659 Granite St Meter Purchases	250,000
	8830-CN4120	01660 Granite St Transformer Purchases	350,000
	8830-CNN002	01737 GSE-Dist-Subs Blanket	50,000
	8830-CNN004	GSE-Dist-Meter Blanket	20,000
	8830-CNN007	GSE-Dist-Water Heater Blanket	121,000
	8830-CNN009	GSE-Dist-Land/Land Rights Blanket	10,000
	8830-CNN012	GSE-Dist-St Light Blanket	225,000
	8830-CNN013	GSE-Dist-Public Require Blanket	400,000
	8830-CNN014	Dist-Damage&Failure Blanket	800,000
	8830-CNN015	GSE-Dist-Reliability Blanket	400,000
	8830-CNN016	GSE-Dist-Load Relief Blanket	75,000
	8830-CNN017	GSE-Dist-Asset Replace Blanket	400,000
	8830-CNN020	Dist-Transf/Capac Install Blanket	10,000
	8830-CNN021	GSE-Dist-Telecomm Blanket	10,000
	8830-CNN022	GSE-Dist-3rd Party Attach Blanket	110,000
	8830-CNN023	GSE Distributed Generation Blanket	75,000
2. Mandated Total			**3,511,000**
4. Regulatory Programs	8830-C18603	Bare Conductor Replacement Program	1,200,000
	8830-C20473	IE - NN Recloser Installations	250,000
	8830-C36423	Mt Support Sub- New LP Fdr Pos	3,700,000
	8830-C36424	Mt Support-New 16L3 Feeder	1,550,000
	8830-C36425	Mt Support-New 16L5 Feeder	100,000
4. Regulatory Programs Total			**6,800,000**
5. Discretionary	8830-C13968	PS&I Activity - New Hampshire	10,000
	8830-C18620	Charlestown 32 Dline	5,000
	8830-C18630	Charlestown DSub	15,000
	8830-C21093	IE-NN Dist Transformer upgrades	25,000
	8830-C22214	NN ERR/Pockets of Poor Perf	50,000
	8830-C26061	NH ARP Relay & related	5,000
	8830-C31402	IE-NN URD Cable Replacement	100,000
	8830-C33766	NEN-NH Electric Fence FY10	25,000
	8830-C36427	Feeder Getaway Cable Replacement	100,000
	8830-C36430	Pelham Sub-Add 2nd Xfmr and Fdr Pos	600,000
	8830-C36431	Pelham-New 14L4 Fdr	350,000
	8830-C42901	Underperforming Feeder Program	50,000
	8830-C42851	Enhanced Bare Conductor Replacement	500,000
	8830-C42852	Pelham-New 14L5 Fdr	150,000
	8830-CNN006	GSE-Dist-Genl Equip Blanket	50,000
	8830-CNN025	IT Systems & Equipment Blanket	25,000
	8830-CNN026	Misc Capital Imprvmnts GSE Facilities Blanket	100,000
	8830-CNN027	Transportation Fleet & Equip. Blanket	250,000
	8830-CRSRVARS_(	Reserve for Sub Asset Repl Specifics	25,000
	8830-CRSRVDF_01	Reserve for Damage/Failure Unidentified Specifics &	75,000
	8830-CRSRVLRL_0	Reserve for Load Relief Unidentified Specifics	25,000
	8830-CRSRVPR_01	Reserve for Public Requirements Unidentified Specifics	50,000
	8830-CRSRVRL_01	Reserve for Reliability Unidentified Specifics	100,000
5. Discretionary Total			**2,685,000**
Grand Total			**15,406,000**

Priority 1 = Safety - there are no safety priority projects in 2016

The annual capital expenditure budget presented to the parent board of directors each December simplifies the underlying details, presenting expenditures in "replenishment", "improvement" and "growth" categories. It measures the net increase in property, plant and equipment assets (rate base) that results. That budget shows the top five projects for LU-NHG and for LU-NHE. The next illustration depicts a page from the 2016 capital budget for New Hampshire, as presented to the parent board of directors on December 3, 2015.

New Hampshire

New Hampshire's capital expenditure budget is expected to be $43.3M million higher tha depreciation expense in 2016. The following is a table and chart summarizing New Hampshire's capital expenditures along with the net increase in PPE.



New Hampshire	2016
Replenishment	18,547
Improvement	29,545
Growth	15,710
Total Capital Expenditure	**63,802**
Depreciation	20,459
Net Increase in PPE	**43,343**

Granite State (Top 5 Projects)	2016
Mt Support Sub- New LP Fdr Pos	3,700
Mt Support-New 16L3 Feeder	1,550
Bare Conductor Replacement Program	1,200
GSE-Dist-New Bus-Comm Blanket	1,200
GSE-Dist-New Bus-Resid Blanket	1,050
Top 5 Projects	**8,700**
All Other	(8,700)
Total	

EnergyNorth (Top 5 Projects)	2015
Upgrade Hi Line - Concord to Tilton	12,000
Main Replacement LPP	9,000
Growth	4,750
Main Replacement City/State Construction	4,500
New Service Residential	3,500
Top 5 Projects	**33,750**
All Other	(1,492)
Total	**32,258**

f. O&M Budgeting

The New Hampshire finance department serves as "coordinator and consolidator" for the annual budget process. The group uses business planning templates to support this effort. The process begins in August for the O&M budget. The senior manager of finance in New Hampshire issues a memo to department managers describing the budget process, and providing detailed instructions and schedules for budget reviews. The key input for department managers is employees added or reduced for the budget year.

The senior manager finance provides planning guidelines and assumptions. Each budgeting department uses the same input template for operating expenses. Each cost center has responsibility for its own budgets. The functional managers with budget responsibility develop operating expense budgets, using a bottom-up approach.

Human resource information and assumptions are provided by Oakville for use by the cost centers. The departments input salaries, office supplies, facilities costs, vehicles and other direct costs into their operating expense budgets. The operating expense budgeting process schedule includes time allowances for budget iterations. Each cost center builds a one-year budget only.

The Company first focuses on refining the first year of the five-year forecast. Each responsible budget area begins with a dollar target that management expects the budgets to approximate. The dollar amount of operating expenses approved in the last rate order drives that target. Management expects first budget iterations to approximate the target, absent specific new initiatives or explanations supporting exceptions.

The development of revenue for the budget is prepared under the direction of the Vice President of engineering and procurement. Oakville provides a "push-down" of the headquarters business services costs and corporate allocations to New Hampshire.

g. Budget Performance Management

Local management for New Hampshire uses a monthly financial reporting process to manage performance to and variances from the annual budget. The accounting books close monthly on about the seventh business day of each month. The senior manager of finance provides a "flash report" on about the fifth business day of the month. It provides a heads up on performance before the books close. The company prepares actual-to-budget-comparisons after the close of the accounting books (on the 8th or 9th business day), termed the President's Report.

Budget reporting to Oakville (and budget variance management) takes place in an "operations call" that occurs in the third week of each month. A PowerPoint presentation is prepared for the Oakville finance group. The call participants discuss it. The New Hampshire state president, vice president-finance, and senior manager finance present the financial results summarized in the PowerPoint presentation. The monthly presentation uses a consistent format that covers the same results and financial metrics for each month and for the year after the books close in January.

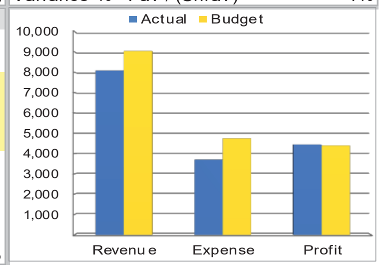
Financial analysis charts are prepared for New Hampshire as a whole and for electric and gas separately. The next illustration depicts the financial analysis format.

Financia l Analys is – NH

Net Revenue - Nov 2015	Fav / (Unfav)
Budget	$9,044
Customer Count	(100)
Volume	(612)
Price	(45)
Keene	119
All Other	(323)
Actual	$8,083
Variance $ - Fav / (Unfav)	(961)
Variance % - Fav / (Unfav)	(11%)

Operating Profit - Nov 2015	Fav / (Unfav)
Budget	$4,389
Revenue variances	(961)
Operating Expense variance	1,053
All Other	(40)
Actual	$4,440
Variance $ - Fav / (Unfav)	51
Variance % - Fav / (Unfav)	1%

Operating Expense - Nov 201	Fav / (Unfav)
Budget	$4,747
Labor	256
Operating Expense	14
Bad Debt Expense	529
Administrative Expense	254
All Other	()
Actual	$3,694
Variance $ - Fav / (Unfav)	1,053
Variance % - Fav / (Unfav)	22%

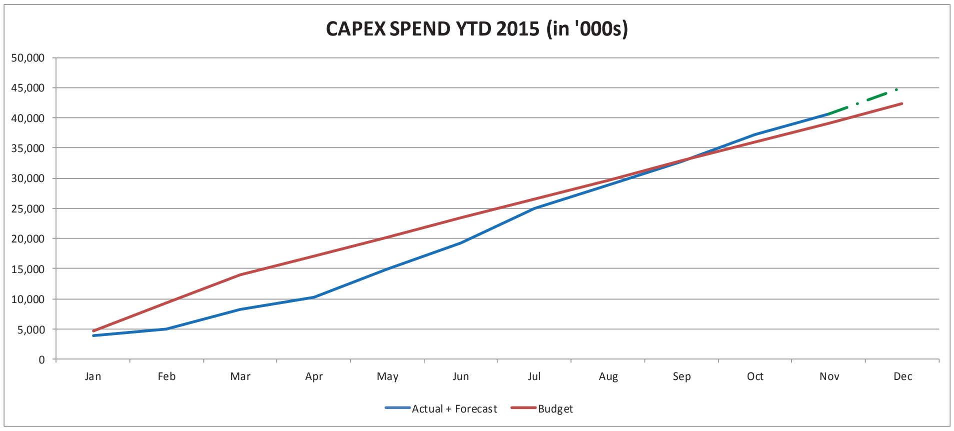


3

Liberty Utilities

Net revenue variances by customer class are also analyzed, as is a breakdown of the components of earnings before taxes (EBIT). The EBIT budget number is shown graphically, and variances in net revenue, operating expenses, business services, corporate services, depreciation and amortization and other income are shown, to arrive at the actual result for the month, quarter, or the year depending on the period being examined. A scorecard is next shown. It includes red and yellow issues (versus green for positive performance). Scorecards are tied to annual goals. Depictions show scorecard measurables whose results are “in jeopardy,” and need attention. The December 2015 presentation included monthly, quarterly and year-to-date performance measurements. The big issues in this particular month were OSHA recordable injuries, vehicle accidents (MVAs), accurate and timely billing, customer satisfaction survey for electric, net income, bad debt expense, and the outreach program.

Capital spending for the year to date is showing on a single chart (illustrated below), showing total New Hampshire CAPEX performance. A chart detailing customer service level trends by month is shown next. Finally, the December 2015 report had three slides at the end related to customer expansion projects and sales on those projects.



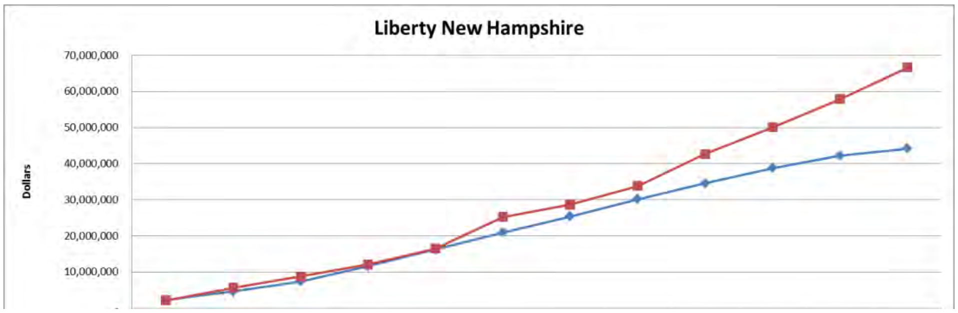
The Vice President-finance notes that the presentation for the operating call is in the same general format for every month.

The manager of engineering has a "separate budget meeting" with the heads of electric and gas engineering, project managers, engineers, and New Hampshire finance managers. A monthly report on capital spending and variances is sent to project managers, who then enter the expected forward spend for each project for the quarter, and through the end of the year. Two project managers, one for gas and one for electric, report to the manager of engineering, and on a monthly basis provide updates for all projects. The project managers also provide updates for spending on the "blanket programs", which are routine categories that are budgeted on an annual basis. The project managers have capital planners on their teams who support capital reporting.

The project managers are responsible for project spending, performance and variances. The project managers are instructed to identify variances before they actually happen to plan mitigation. If capital spending above the project budget is expected, a re-authorization request for additional capital is prepared and sent to Oakville finance. At the end of the year, the manager of engineering prepares a report that explains the CAPEX variances and lessons learned. A memorandum on 2014 capital expenditures variances dated November 1, 2014 addresses these particular issues:

> *In accordance with the Liberty Utilities Project Expenditures Policy and Procedure, the local management team is responsible to close out the capital year spend through the Overage/Underage process. For all projects, over-budget variances exceeding 10% (Minimum $50,000) of the approved budget requires approval by the local management team (Local Director of Engineering and State President). Under budget variances will be reviewed in the project close out report and will be reviewed at the local level….*
>
> *The Liberty Utilities capital budget team has agreed to conduct the budget overage/underage reconciliation at the end of the fiscal year.*

The New Hampshire finance group prepares a year-end financial results recap in the form of a PowerPoint presentation. The topics covered in the presentation are an "Efficiency Scorecard" that includes financial returns, an EBITDA analysis for New Hampshire, an operating cost analysis for New Hampshire, net revenue analyses for both electric and gas, a brief "Efficiency Analysis" and the New Hampshire total capital spending chart by month, as shown below. These presentations were prepared for 2014 and 2015 and were provided for review. The chart below purports to show capital spending for Liberty New Hampshire for 2014; capital expenditures exceeded the approved budget by about 22.5 million, or approximately a 50 percent overspend. Note that these results are not consistent with company reconciliations performed at a later date.



C. Conclusions

1. Liberty Utilities' strategic plans, as complemented by five-year forecasts, are well organized and thorough, presenting a clear vision, mission and strategies.

Liberty Utilities has a clearly stated vision, mission, investment thesis and values that are communicated through the strategic plan. The vision and mission set the tone and direction for planning and operating the company. Liberty Utilities prepared formal strategic plans in 2013 and 2014; each covered the immediately following five-year planning period. A strategic plan was not prepared in 2015, but a five-year forecast was prepared and utilized.

The strategic planning processes in 2013 and 2014 each began with a "SWOT analysis" prepared by the Liberty Utilities state presidents and the top 10 officers of Liberty Utilities. The SWOT analysis is intended to drive the focus of strategic planning for the next five years. The New Hampshire state president has input on the direction and focus of strategic planning on the front end as a result. The formal strategic plan is prepared by Oakville planners and executives, which is appropriate for high-level planning.

The New Hampshire utilities also have input to the strategic plan through the development of a five-year capital plan that is included in the five-year forecast. This input is the opportunity to place New Hampshire's future capital needs into the strategic planning process for consideration.

2. Strategic plans and five-year forecasts focus on acquisitions and organic growth initiatives to meet aggressive financial metric targets.

The Liberty Utilities five-year forecast includes specific targeted financial metrics around which the forecast is constructed. The scenarios developed for the forecast include at least one "Directional scenario" that will meet all of the financial goals for five years. For instance, the 2014 strategic plan and financial forecast included the following target financial metrics:

- Double EBITDA in five years
- Grow EBITDA in every year
- Grow EBITDA on existing assets in every year
- Maintain a triple-B credit rating.

The Directional scenario was constructed to meet all of these five-year financial objectives. In addition, the Directional scenario included the target financial metrics, plus an EBITDA interest coverage minimum, a total debt to capital maximum level and an FFO/Debt metric of 13 percent for the regulated utilities. The acquisition of Park Water in 2016 and investments in LNG in 2015 through 2017 were added to the Baseline. Hypothetical acquisitions were planned in 2018 and 2019. The result of the Directional forecast was to double EBITDA from 2015 to 2019, as was targeted in the process. The Directional scenario in this five-year plan is clearly built to show the type of growth projects and growth levels that would be required to meet the five-year financial objectives.

3. **Strategic plans have strategies and initiatives for operations, human resources and customer service, but specific goals and target metrics are not evident.** *(Recommendation 1)*

Operating strategies and initiatives had a clear and prominent place in the 2013 and 2014 strategic plans and related five-year forecasts. Strategies included human resources initiatives and operations initiatives related to customer service. However, we observed no target metrics for measurements for human resources, customer service, or operations and reliability set forth in the strategic plans or the five-year forecasts.

Specific and measurable metrics for these functional operations are needed in strategic planning to set specific goals and target levels that are "bought into" at the executive and Oakville levels, while also being understood by local employees. Target operational metrics will also allow the Oakville headquarters to monitor performance against operational metrics, which is required for effective operational control over the New Hampshire operations.

In contrast, the five-year forecasts include very specific financial metrics around which the forecasts are built. Such target metrics should also exist for important operations and service levels.

4. **Capital expenditure envelopes allocated by the Oakville headquarters have not been restrictive for New Hampshire operations.**

An important outcome of strategic planning and five-year forecasts is the allocation of capital at the holding company level, and its adequacy for New Hampshire utility operations. The process for determining the level of capital expenditures for New Hampshire operations that are included in the five-year forecast is shown in the kick off instructions, "Scope of Deliverables" prepared by Oakville finance:

> *Oakville to work with regions to establish envelope of CapEx that satisfies ROE% requirements… Oakville will have one-on-one discussions with regions early next week (March)*

As noted by this passage, Oakville finance and New Hampshire executives discuss capital expenditure levels for the five-year forecast. New Hampshire supplies a proposed five-year capital expenditure plan that local management believes should meet operational needs. Oakville finance seeks to ensure that long-term financial goals are met, which is a function of assumptions regarding capital expenditures and cost recovery thereon. The two parties work to determine an "envelope", or range of capital expenditures for each forecast year. This envelope represents a "soft cap" on capital expenditures based on financial metrics.

The total New Hampshire levels for capital expenditures included in the 2015 five-term forecast for the years 2016 through 2020 was $54 million for 2016, and between $40 million and $48 million in each the following four years. We believe that these levels represent sufficient allocations of capital expenditure dollars for New Hampshire operations, based on past capital budget levels.

We also note that the company has an Emergent Program Process to add capital projects or programs to the approved capital budget that "emerge" during the budget year. This process should provide additional flexibility for the New Hampshire operations to obtain the capital required to fund effective utility operations.

5. Strategic planning and the five-year plan are effectively linked to the budgeting processes.

The Liberty Utilities strategic plan and the five-year forecast are developed in an annual planning process that begins in March and ends in July with a presentation to the Algonquin Board of Directors. Both the strategic plan and five-year forecast include a five-year capital plan that is a key component in building the plan.

The board presentation provides a forum for executive and board of directors' questions and comments regarding the plans. Following the presentation and board comments and any adjustments required, the plans are "finalized" (but not approved by the board), and the Liberty Utilities budgeting processes begin. Using the first year of information in the five-year forecast as a template, budgets are developed from the bottom-up that refine the first year of information.

Budgets are the execution plan for the first year of the strategic plan, including approvals for one year of capital expenditures and operating expenses. The strategic plan, five-year forecast and the budget are closely linked by this process. The budget execution plan should show substantive progress in the first year of the strategic plan toward meeting its five-year goals and objectives.

6. Budgeting processes for operating expenses, revenue and earnings are generally well organized, timely and effective.

The New Hampshire budgeting process for operating expenses, revenue and earnings are effective and efficient in both their construction and results.

The first focus in the operating budget process is to review and refine the first year of the five-year forecast. Each responsible budget area begins with a dollar target that management expects the budgets to approximate. The dollar amount of operating expenses approved in the last rate order drives that target. Management expects first budget iterations to approximate the target, absent specific new initiatives or explanations supporting exceptions.

The management reporting process to Oakville and budget variance management takes place in an "operations call" that occurs in the third week of each month. A PowerPoint presentation is prepared for the Oakville finance group that is presented and discussed on the operations call. The monthly presentation is in a consistent format that covers the same results and financial metrics for each month and quarter.

The New Hampshire finance group also prepares a year-end financial results recap in the form of a PowerPoint presentation. The topics covered in the presentation are an "Efficiency Scorecard" that includes financial returns, an EBITDA analysis for New Hampshire, an operating cost analysis for New Hampshire, net revenue analyses for both electric and gas, a brief "Efficiency Analysis" and the New Hampshire total capital spending chart by month. The 2014 EBITDA for LU-NH was $43.8 million, or $2.9 million greater than the budget, a 7 percent favorable variance. Actual operating expenses were about $2.5 million over budgeted amounts, or a negative variance of about 4.5 percent.

In 2015, earnings before taxes were about $3.3 million, or about 14.8 percent below budget. The negative variance was caused primarily by depreciation and amortization expenses that were $5.4 million greater than budget, despite positive performance in net revenue and operating expenses of about $3.3 million.

7. **The CapEx budgeting process does not provide required analysis, business cases and detailed cost estimate packages prior to budget presentation to and approval by the local management, Oakville senior management, or the parent board of directors.** *(Recommendation 2)*

Liberty Utilities – New Hampshire has significant timing issues in providing capital expenditure analysis and business case packages for review and approval at executive levels. The CapEx budgeting process is one of the most crucial in effectively operating capital-intensive utility companies, making insufficiencies in this area a significant management issue.

The budgeting processes for the 2016 budget cycle specified that completed budgets, including the capital budget, were to be submitted to New Hampshire finance by September 3, 2015. The budgets were consolidated and submitted to the state president for first review by September 11th. Several budget iterations then occurred between department heads and the state president prior to his approval. The budget is then sent to the Oakville finance group. During October and November, the New Hampshire budget is discussed between the state president and Oakville, prior to approval by Oakville finance in November. A budget presentation is prepared for the parent board of directors, to be reviewed and approved in early December.

All analysis, business cases, capital expenditure applications and detailed cost estimates should be completed, packaged and presented to the New Hampshire state president for review and approval before the middle of September. When the capital expenditure packages are sent to Oakville, its management should also review the entire capital expenditure packages before approving the New Hampshire budget in November.

Our review of the capital budget packages for the budget years of 2014, 2015 and 2016 found that the packages were dated and approved by New Hampshire during the budget year -- not prior to budget review by the state president in September of the previous year. In fact, the capital packages were not approved until May 1, June 1 and March 31 of the budget year in 2014-2016, respectively. Thus many projects were well underway before they had been analyzed and approved by managers. Since this information was not prepared until several months later, the state president, Oakville finance and the parent board were approving capital budgets of 80 plus line items that appeared not to have been:

- Fully analyzed
- Subjected to consideration of alternatives
- Supported by business case and capital expenditure applications
- Subjected to detailed cost estimates.

The table below is a recap of the timing of the capital budget packages for the 2014, 2015 and 2016 capital budgets. The packages generally included an abbreviated 1-page business case and a 2-page Capital Project Expenditure Application.

	Date	Approved by Manager	Board Budget Approval Year	Projects Start	Projects End
2014 Projects	5/1/2014	5/1/2014	2014	1/1/2014	12/31/2014
2015 Projects	6/1/2015	6/1/2015	2015	1/1/2015	12/31/2015
2016 Projects	1/1/2016	3/31/2016	2016	1/1/2016	12/31/2016

8. **The New Hampshire capital budget packages do not provide detailed business case analysis for the growth, discretionary and regulatory supported projects as specified in the applicable Capital Expenditure Policy.** *(Recommendation 2)*

Liberty Utilities has a Capital Expenditures Planning and Management Policy and Procedure document (Version 2.1 dated September 21, 2015). However, the New Hampshire operations are not following the policy requirements, especially the requirement that business cases be fully prepared for certain types of expenditures.

Under Section 8.1 of the policy, specifications for the requirement of business case preparation are presented:

8.1 Business Case

The following types of projects require a business case to be approved:

- *Growth, Regulatory Supported and Discretionary projects, or portfolios, over $50,000*
- *Unplanned projects over $50,000, outside of safety where an expenditure application should be used*

The policy provides a business case example that shows the type of categories and information and analysis to be provided. These business case categories are: recommendation, objective, background, alternatives/options, financial assessment, risk assessment/qualitative evaluation, and implementation/action plan.

With regard to at least three of the categories, management has not prepared the types of analysis required for its business cases for each of the budget years 2014 to 2016. Management did not provide the types of analysis prescribed for growth, discretionary and regulatory supported projects regarding alternatives/options, financial assessment and qualitative evaluation. The capital expenditure policy for business cases is specific in the type of analysis expected. In particular, we did not find alternatives identified and analyzed, and net present value or internal rate of return analysis was not prepared (as required in the Policy) in the business cases that we reviewed.

9. Recent capital expense variances demonstrate a lack of effective control of capital expenditures. *(Recommendation 3)*

Combined, the electric and gas businesses in New Hampshire experienced capital budget over runs of over 70 percent in 2014. Not only was the total variance large, but the individual variances that comprised it were many and in some cases extremely large. The causes were multiple, and the effects hit both the gas and electric businesses in New Hampshire. We observed:

- Extremely large overruns on individual projects
- An overrun of close to 20 times the corporate IT charges budgeted to be assigned to New Hampshire
- A $10 million charge to New Hampshire for a "finance project" (similar to that described earlier) that had not been in the capital budget at all
- An increase of $12 million in New Hampshire capital costs for unbudgeted growth projects, carryover of work from 2013, and mischarged costs
- Over $10 million in under-runs due to project delays.

The number, size, and nature of the variances is extraordinary, and present a picture much more of opportunistic than well-planned capital spending. Our review evidenced widespread capital planning problems and capital budget execution. APUC's circumstances heighten the concern further in that utility operations must compete for capital with other demands imposed by a company with an unusually aggressive growth strategy, particularly one that involves acquisitions as a central element. Also discomforting is the repeated emphasis that planning documents show for investments that drive returns, as compared with less detail and emphasis on utility operating metrics.

Capital expenditure performance in 2014 did not give confidence that the details underlying capital plans (see the preceding conclusion) or attention in managing to those plans is effective.

The total New Hampshire capital budget variance dropped remarkably in 2015, but that drop should not mask what remains a striking number, size, and breadth of variances at the detailed level. The continuation of these variances confirms the concerns about details underlying capital plans (see the preceding conclusion) and whether or not the attention in managing to those plans is effective.

The variance for LU-NHG was low (about two percent). The LU-NHE variance remained high enough to be of concern (costs exceeded budget by 15.1 percent). The continuing large number and magnitude of capital budget variances at the line item level, and the many and varied reasons for the variances continue to evidence a lack of effective capital planning and capital budget execution.

Major variances were recorded on almost every line of the electric and gas 2015 capital budgets. Gas budget "over-runs" totaled about $16.7 million, but were more than offset by about $18.3 million of "under-budgets". In other words, $35.0 million of variances were recognized, on a budget of only $32.3 million. The problem with these huge variances on individual projects and programs is that the capital budgets prepared for and approved by New Hampshire management, Oakville management and the parent board of directors simply are simply not being followed. Dollars are not spent on the capital categories represented in the approved budget.

10. New Hampshire and Oakville management did not effectively monitor and control problems with capital budget timing or 2014 and 2015 capital expenditure performance. *(Recommendation 4)*

Conclusion 7 above reports that important analysis, formal applications and project estimating work on capital budgets occurred well after senior management and Board of Directors approvals of the capital budget for each the 2014, 2015 and 2016 budget years. New Hampshire executive management and Oakville executive management approved each of these capital budgets without important analytical and estimating work having yet been performed or reviewed. The capital expenditure approvals were based on insufficient evaluations and assessments performed by senior management as a result. The capital budget processes violate the company's own capital expenditure policies as well as that of good utility business practice.

The monitoring and control of capital expenditures also shows little attention paid to this area as compared with greater focus on earnings, revenue and operating expenses. New Hampshire's monthly reports to Oakville include a single chart measuring capital expenditure spend to budget in total, and does not include any analysis. Year-end reports by the New Hampshire utilities to Oakville include analysis on EBITDA, operating costs, net revenue, funds from operations and organic growth. Again, the one-page capital expenditure chart with no analysis is presented.

Also included in the 2014 year-end presentation was an "Efficiency Scorecard" that reports Capital Budget Efficiency scores are "100%" for actual expenditures with a target of 100%. This scorecard misleadingly indicates excellent performance on the capital budget. In the same document, however, capital expenditure actuals are shown at $66.6 million and the budget at $44.1 million. We also note that the actual capital spend was inaccurate, as capital expenditures were later reported as $77.3 million for 2014. The lack of accurate information in the year-end reports also does not indicate effective monitoring or control of the capital budget.

11. New Hampshire executive management and Oakville executive management did not take action to mitigate problems with capital budget process timing and reconciliations of 2014 capital expenditure performance. *(Recommendation 4)*

Senior management at the New Hampshire and Oakville levels has apparently not taken effective action to change the timing of the capital expenditure processes noted in previous conclusions. The capital analysis packages for the 2016 budget were prepared well after senior management and Board approvals of the capital budget, as was also the case in 2015 and in 2014.

The New Hampshire engineering department prepared a variance reconciliation and explanation on a line-by-line basis for the 2014 capital budget. This reconciliation and analysis was reportedly prepared in July 2015. The 2015 capital variance analysis was prepared in early May 2016. We believe that such an important management tool for the capital expenditure budget should be prepared as soon as possible after the books close for the year in January. The lack of timely analysis causes Liberty to conclude that appropriate management action to fix problems with the capital expenditure budget have not yet been implemented.

New top New Hampshire leadership was not present during 2014. We understand leadership's view as not being aware of any 2014 capital budget problems and as focusing on actual levels of capital spend as compared to budget late in 2015, focusing on conforming to the total dollar budget. Under the circumstances, a more granular view appears necessary to bringing meaning to capital planning for New Hampshire.

D. Recommendations

1. **Incorporate into the Liberty Utilities' strategic plans and five-year forecasts specific operational metrics as objectives for the planning process.** *(Conclusion 3)*

Liberty Utilities' five-year forecasts are driven by targeted financial metrics that are clearly defined. Liberty believes that operational metrics should be included in the five-year forecast that also drive the planning process, and allow increased monitoring and management of operational issues by Liberty Utilities, Oakville and the holding company.

2. **Redesign and rigorously apply the capital budgeting process so as to ensure the provision of full project business cases and program capital expenditure applications by September for the following budget year.** *(Conclusions 7 and 8)*

Business cases for growth, discretionary and regulatory support should also be performed according to the company's capital expenditure policy, which includes NPV analysis for these projects. The budget process should result in capital packages that are finalized and approved by (sequentially) the state president, Oakville finance and by the parent board of directors in December.

3. **Manage the capital budgets to annual variance tolerances of plus or minus 5 percent for total expenditures and plus or minus 20 percent for individual projects and line items.** *(Conclusions 9)*

Liberty Utilities New Hampshire should establish and use variance tolerances for capital expenditure budget performance that are specific and provide measurements for performance levels. For instance, "good performance" tolerances should be 5 percent or less, moderate be 5 to 10 percent, and unacceptable for 10 percent or more of the total budget. Tolerances should also be established for individual projects and line items, to emphasize and ensure that capital budget management produces the spending on the priorities and specific needs that are addressed in the Approved Capital Budget.

4. **Change monthly and year-end management reporting processes to include monitoring and detailed analysis of capital expenditure spending and variances.** *(Conclusions 10 and 11)*

Monthly management reports and meetings at the New Hampshire level should start to include capital budget reporting, variance analysis and variance mitigation on a line-item basis. Management of the capital budget must become a greater focus for the state president and vice president – finance.

5. **Replace the monthly "operating call" presentations and year-end management reporting processes with Oakville with a more structured, documented monitoring and detailed analysis of capital expenditure spending and variances.** *(Conclusions 9 through 11))*

Oakville should begin to monitor and manage line item performance of the capital budget on monthly, quarterly and annual bases.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

Department of Energy Data Requests - Set 2

Date Request Received: 6/2/23
Request No. DOE 2-12

Date of Response: 6/12/23
Respondent: Anthony Strabone

REQUEST:

Please provide a copy of the most recent and current "Liberty Way" policy and procedures for capital expenditures.

RESPONSE:

Please see Attachment DOE 2-12.

Liberty™

Name	Version No.
Capital Expenditure Planning and Management	4.0
Doc No.	Effective date
100-220-200-001	12/31/2013
Owner	Last approval date
Peter Eichler, Senior VP, Regulatory Strategy and Central Services	07/18/2022
Approver	
Gerald Tremblay, Senior VP Operations	

Capital Expenditure Planning and Management

Table of Contents:

1. **Purpose** 3
2. **Scope** 3
3. **Definitions** 4
   3.1. Blanket Projects 4
   3.2. Capital Project 4
   3.3. Discretionary 4
   3.4. Functional Lead 4
   3.5. Growth 5
   3.6. Growth Portfolio 5
   3.7. IT Capital Portfolio 5
   3.8. Mandated (by regulations or laws) 5
   3.9. Project Champion 5
   3.10. Project Completion 5
   3.11. Project Manager 5
   3.12. Project Sponsor 6
   3.13. Regional President 6

3.14. Regulatory Supported 6
3.15. Safety 6
4. Capital Planning vs Capital Budget Process 6
4.1. Assumptions 7
5. Applications for Capital Expenditure Approval 8
5.1. Communications of Approvals and Approval Limits 9
5.2. Planned and Budgeted Safety and Mandated Projects 9
5.5. Variances to Budget or Schedule 10
6. Capital Expenditure Documentation 11
6.1. Business Case 11
6.2. Capital Project Expenditure Form 13
6.3. Change Orders 14
6.4. Project Closeout Report 14
7. Reporting 15
7.1. The Monthly Operations Review 15
7.2 Monthly Capital Project Reporting 16
7.3 Monthly Cash Spend Reporting 16

Appendix A: Capital Project Expenditure Form
Appendix B: Business Case Template
Appendix C: Monthly Capital Project: Reporting for Period End
Appendix D: Change Order Form
Appendix E: Project Closeout Report
Appendix F: Capital Budget Cycle

1. **Purpose**

Liberty Utilities Co. and its subsidiaries (collectively "LU") incur capital expenditures for a variety of projects each year depending on growth trajectories, maturation of assets, statutory requirements, and extraordinary occurrences. Both planned and unplanned capital expenditures designed to meet business needs are to be subject to the policies and procedures in this document.

Five categories will be utilized to organize and prioritize Capital Expenditure requests. The categories are as follows in descending priority:

- Safety
- Mandated
- Growth
- Regulatory Supported
- Discretionary

For Safety and Mandated initiatives, a Capital Project Expenditure Form ("CPE") must be completed and approved regardless of the project size in order to commence with project activities.

For Growth, Regulatory Supported, and Discretionary initiatives greater than $100,000, a completed Business Case and CPE Form (excluding the CPE-Financial Summary section) is required for approval to commence with project activities, while projects with estimated costs less than $100,000 will require a CPE Form completed in order to commence with project activities.

For cases where there may be a blanket of projects combining Safety & Mandated with Growth, Regulatory Supported, and Discretionary the process followed for project approval shall be as outlined in section 5.3.

This document also provides direction as to the level of autonomy regional and functional leadership can exercise as well as procedures to address changes, material variances, ongoing reporting, and expenditure closeout.

2. **Scope**

To define the processes related to approving, monitoring, and reporting capital expenditures to ensure:

- Appropriate documentation is:
  - Prepared to reflect proper necessity, scope, cost, and schedule;
  - Documentation is provided as part of the approval process; and
  - Retained in historical records in accordance with regulatory requirements and needs.

- Appropriate authorization is obtained before the start of all projects.
- Consistent evaluation of capital projects across the enterprise.
- Projects are completed within planned time frames, to approved cost allocations
- and with full scope delivery.
- Material changes to scope, timing, and costs are authorized appropriately by the regional or corporate leadership prior to their occurrence.
- Effective and efficient deployment of capital resources across the enterprise are managed by regional leadership such that reallocation of capital according to evolving requirements, and priorities change within the region can be executed.
- Financial gains and ancillary benefits used to justify initiatives are achieved and impacts are reflected in subsequent monetary budgeting activities.

3. Definitions

Capital projects are projects which are net new to the company or spend which results in the furtherance to the life of an asset. Capital projects at LU are broken into five categories used to assess proposed projects. Respective definitions are provided below. These categories are to be used in both the development of regional capital projects and during the monitoring phase once projects are approved.

3.1. Blanket Projects

Blanket projects are various smaller capital initiatives that are grouped together to constitute a total spend for projects with similar scope.

3.2. Capital Project

A Capital project, both planned and unplanned, are designed to achieve stated objectives where one of the outcomes is materialization of, or improvement to, assets that can be listed on the company's Statement of Financial Position.

3.3. Discretionary

All other capital expenditure projects that do not fit within the four prior grouping will be grouped under the "Discretionary" category. The merits of each project will be assessed individually.

The following definitions are commonly used terms in this document. To prevent misunderstandings, or misinterpretations, explicit definition is provided below.

3.4. Functional Lead

Functional Leads provide corporate strategy, policy and procedural definition for their respective area of knowledge. They are accountable for defining and maintaining the framework under which regional businesses operate.

3.5. Growth

Expenditures categorized as "Growth" are those used to expand the physical plant. For example, projects such as extending distribution mains or services, installation of new feeders, and expansion of substations. For capital expenditures where a gas, electric, or water system Line Extension Policy exists and is supported through approved regulations, the management and reporting of individual transactions is exempt from this policy. Rather, activities will be aggregating into a portfolio and managed as a grouped entity.

3.6. Growth Portfolio

To avoid the burdensome chore of administering and reporting on individual customer connections or line extension as independent projects, Growth projects are to be pooled into a group named "Growth Portfolio".

3.7. IT Capital Portfolio

For any LU software application in any work process or functional group the procedure would follow the PMO -1.0 – Work-In-Take Process.

3.8. Mandated (by regulations or laws)

Expenditures categorized as "Mandated" are those used to meet statutory or regulatory compliance. To qualify for inclusion in this category, proposed initiatives must provide a copy of any applicable legislation, statute or regulation.

3.9. Project Champion

On behalf of the Project Sponsor, the Project Champion is accountable for completing project documentation and facilitating approvals. In some scenarios, the project champion may be the Project Manager; however, it is acknowledged that many permutations exist where the two roles are separate. In the absence of a Project Manager, the Project Champion is responsible for ensuring appropriate job codes are established in Oakville and the regional utilities.

3.10. Project Completion

The Project Completion is dictated by the handover of the final product to the operations group and the closing of all the contracts and work order associated to the project spend.

3.11. Project Manager

The Project Manager is the individual tasked to drive the project on behalf of the project sponsor and achieve the stated objectives. Where a Project Manager has been assigned, they are responsible for adhering to the required documentation (i.e., Business Case and/or CPE), in additional to obtaining relevant FWO codes (to be referred to as Work Break Down Schedule (WBS) in

SAP System) via the regional LU accounting teams. Project Managers, in the absence of explicit direction, will always abide by Project Management Body of Knowledge principles.

3.12. Project Sponsor

The Project Sponsor is the individual with demonstrable interest in the outcome of a project who is ultimately responsible for securing financial and workforce resources to achieve stated objectives.

3.13. Regional President

Regional Presidents, also referred to as the Regional Lead, oversee their respective utilities and are accountable for achieving financial and operating metrics for their respective businesses. Regional Presidents have authority over workforce and capital resources granted to them provided that utilization is consistent with established corporate policies.

3.14. Regulatory Supported

Expenditures categorized as "Regulatory Supported" are those used to implement projects where special regulatory mechanisms have been established to accelerate the financial returns of specific initiatives.

3.15. Safety

Expenditures categorized as "Safety" are those used to reduce workplace hazards, accidents and exposure to harmful situations and substances. It is noted that expenditures addressing imminent dangers would be completed when identified.

4. Capital Planning vs Capital Budget Process

The journey to define capital budgets is often an iterative process characterized by the need for timely and accurate information in order to make informed decisions. The act of developing a budget is outside the scope of this document. For illustration purposes, the Capital Budget process workflow (Appendix F) depicts a simplified budgeting process typically carried out annually between LU and the ultimate parent company, Algonquin Power and Utilities ("APUC").

In Summary, the Corporate Long Term Model is the driver for setting the capital budget for a succeeding year. At the time of forming a succeeding year's capital budget, a preliminary Business Case and/or CPE Form may be submitted for each project prior to the conclusion of the Corporate Long Term Model.

Once the Corporate Long Term Model and related capital budget is set by the APUC Board, Regional Liberty leadership are responsible throughout the successive year for planning the projects that fall within that year's set capital budget, inclusive of review and approval of CPE Forms and Business Cases not already submitted as part of the capital budget formation process.

4.1. Assumptions

4.1.1. As an input to the procedures outlined in this document, it is assumed all LU capital budgets are developed and approved outside of the activities governed by this document. This document details how expenditures are planned and monitored but does provide direction as to how budgets are to be derived in conjunction with APUC or LPCO.

4.1.2. Capital projects submitted as part of the annual budget process are approved as part of the larger capital expenditure envelope of spend for any given year. Prior to actual spend on a specific project, the respective LU region will have to follow procedures noted under section 5 of this document.

4.1.3. This Policy assumes that Regional and APUC Boards have authorize the envelope of spend for the succeeding years Capital Program.

4.1.4. This Policy assumes that the regional accounting teams have utilized US Generally Accepted Accounting Principles (US GAAP) is assessing capitalization of spend on the respective capital projects. For a further discussion on this process please see the Liberty Utilities Capitalization Accounting Policy.

4.1.5. As an input to the procedures in this document, budgets assigned to regions or functional groups are the responsibility of those parties. As such minor variances to approved projects or portfolios are to be handled within given budgets.

4.1.6. The Integrated Technology (IT) Project Management Office's (PMO) Work In Take (WIT) process is outlined within the PMO -1.0 – Work In Take Process and

4.1.7. should be followed in accordance with the rules set forth in that document as is beyond the scope of this procedure. For assistance on this process please contact the LABS IT Group.

4.1.8. Regulatory approved line extension policies outlining specific eligibility criteria and rates of return exist outside of content represented in this document. Expenditures exercised under granted customer connection budgets are exempt from this policy.

4.1.9. All LPCO Business Development projects which follow the stage gating process, are excluded from this document and should be governed under the APMM (Algonquin Project Management Methodology) policy.

5. Applications for Capital Expenditure Approval

All project submissions will have a completed financial assessment pursuant to the following thresholds:

- Safety and Mandated projects will require a completed CPE Form.
- Growth, Regulatory Supported, and Discretionary projects with a capital cost below $100,000 will require a completed CPE Form.
- Growth, Regulatory Supported, and Discretionary projects with a capital cost greater than
  $100,000 will require a completed Business Case as well as a CPE form. Note: the Financial Summary section of the CPE form will not be a requirement as this information is captured within the accompanied business case.
- In the event that there is an unexpected, or emergency service disruption which requires immediate capital spend without sufficient time to follow the protocols noted in this policy, the capital spend can be spent on an emergency basis, however, within five (5) business days after the emergency event occurring a CPE form must be completed and submitted for approval pursuant to section 5.2.
- All Blanket Projects combining Safety & Mandated with Growth, Regulatory Supported, and Discretionary shall follow section 5.3.
- All Unplanned Projects will follow those rules outlined in section 5.4 below.
- In summary, the below table outlines the required documentation that will be discussed in sections 5.2 to 5.4:

Table 1: Capital Expenditure Documentation by Category

Category	Amount	CPE	Business Case	Project Close Out Report	Over Expenditure Application
Safety & Mandated	All amounts	Required	N/A	Required	When necessary
Growth, Regulatory Supported, Discretionary	<$100,000	Required	N/A	Required	When necessary
Growth, Regulatory Supported, Discretionary	>100,000	Required (Cost Sections not required)	Required	Required	When necessary

Instructions for filling out the CPE Forms and Business Cases along with best practices for project estimation and key project metrics can be found in section 6.1 and 6.2 respectively.

For multiyear projects, budgets are defined annually. Every effort will be made to support the capital resources required for multiyear projects.

5.1. Communications of Approvals and Approval Limits

The approval limits for the creation of work orders within the LU financial systems are outlined in Table 2.

Table 2- Approval of Authority Limits	
Level	**Value (USD or CDN)[1]**
CEO	Over $7,500,000
Executive Team Member/Executive VP	$7,500,000
Senior Vice President	$3,500,000
Regional President (LU)[2]	$3,000,000
State President, GM &VP (LU)	$2,000,000
VP	$1,000,000
Senior Director	$500,000
Director	$300,000
Senior Manager	$200,000
Manager	$100,000
Supervisor	$10,000
Staff (requisitioner/buyer[3])	TBD[4]

Approvals for purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

5.2. Planned and Budgeted Safety and Mandated Projects

Expenditures categorized as Safety or Mandated in the approved budget are authorized to commence provided that each project has a completed and approved CPE Form. Project details must be entered into the Clarity financial system. Each project should be entered as follows:

5.2.1. Blanket/Program Project work orders will be established annually to capture work that is part of the normal business cycle and utilizes standard construction materials, methods, and resources.

[1] These levels do not fluctuate to follow Foreign Exchange (irrespective of currency- USD or CDN).
[2] International Presidents will have the same limits as Regional Presidents.
[3] Buyer: The individual(s) responsible for generating a commitment with a vendor to perform services or deliver material or equipment. Such individual is appointed by the director of the area and is responsible for the physical and financial management of the object of the contract and for assuring the strict observance of contractual clauses, including those relating to the monthly measurement of the services contracted and associated indicators, the fulfillment of deadlines, and cost and quality commitments.
4 Must be enabled on a department by department basis by appointing an approved member of the staff.

5.2.2. The CPE Form will be utilized to summarize the scope, cost, and schedule for blanket projects. The form shall be updated annually as part of the Approval process.

5.2.3. Specific Projects will be established and budgeted to reflect work of a unique, one-time project nature. A CPE Form will be required for such projects prior to commencement of construction.

Once a project has started, material changes to the timing or variances relative to initial cost will be captured and reported pursuant to section 7 of this policy. A material change to the timing of a project is defined as the movement of an in- service date from the scheduled quarter and in to a new one.

5.3. Planned and Budgeted Growth, Regulatory Supported/Discretionary Projects

Projects included in the budget as Growth, Regulatory Supported or Discretionary groups and projected to have a cost of less than $100,000 will require a completed CPE Form and follow a similar approval process to that of Safety and Mandated projects.

Projects included in the budget as Growth, Regulatory Supported or Discretionary groups and projected to have a cost of greater than $100,000 will require a more robust review of the project to assess its scope, schedule and benefits.

For projects over $100,000, a business case must be completed along with a CPE Form as outlined in section 5.0 above. A blanket Business Case can be used for projects where many smaller transactions collate in to one initiative. Similarly, a business case can be used for a portfolio of activities. All projects in these categories will be assessed based on the following criteria:

5.3.1. Operational risk, and

5.3.2. Business objectives.

5.4. Unplanned Projects

Projects that are deemed unplanned will be those projects that were not allotted for in the annual capital planning process or approved within the final annual budget book document. The unplanned projects will be reviewed and approved pursuant to the same manner as noted in sections 5.1 to 5.3 of this document.

5.5. Variances to Budget or Schedule

Any project variances must be approved pursuant to approval limits noted in section 5.1 of this document. A variance threshold of 10% for budget variances shall require approval. Variances are defined as:

5.5.1. The overall out of scope project costs that draw the full approved estimated project contingency and overrun the respective cost category items outlined in the business case or CPE form; or

5.5.2. Expected completion date extends beyond originally defined fiscal year impacting capital budgets or stated business case objectives; or

5.5.3. Scope of deliverables is materially different from what was chartered and approved in the business case.

For multiyear projects, monetary variances are to be tracked both an annual and total project basis. Reporting is carried out pursuant to section 7.2 of this policy.

Material changes in schedule are defined as any delay resulting in a completion date outside of the original scheduled operating quarter. Regional leadership is responsible to manage delays and changes in cash flow to ensure financial metrics are sustained for their respective businesses. The Project Manager is accountable to communicate expected variances to regional leadership when identified, ideally before the variance has occurred. All schedule and cost variances are to be inputted into clarity to accurately reflect any scope growth or project delays.

No expenditure shall be made to cause a project to be over-budget without formal approval unless the delay results in adversely affecting the project or the operation of the company. In case of an emergency the Regional President should take appropriate action to preserve life and public safety.

6. Capital Expenditure Documentation

Samples of templates are provided in the appendices. Standalone versions of the documents can be separately obtained on the Community SharePoint.

6.1. Business Case

As noted in Table 1 of this document, both planned and unplanned projects classed as a Growth, Regulatory Supported or Discretionary projects and having a value greater than $100,000 will require a completed business case.

It is the responsibility of the Project Manager, or Champion, to prepare the business case, with assistance from appropriate stakeholders. The key sections found in the Business Case form and the general guidelines required to successfully complete this stage of the project planning process are outlined as follows:

6.1.1. Project ID#: This represents the unique project code that defines the project during the budget cycle

6.1.2. Project Scope Statement: This may include but is not limited to deliverables associated to the project, the acceptance criteria, what will not be included in the project, and any assumptions or constraints

6.1.3. Background: This section shall:

I. Describe the current operational asset and risk of not carrying out the respective capital project.

II. Describe any related project previously approved for this project and any funds previously spent that are related to this proposal.

III. Describe the decision criteria used in evaluating the alternatives: i.e., Work process improvement, system improvement, etc.

6.1.4. Recommendation/Objective: This section should look to answer why the Project Scope Statement is looking to be resolved along with the recommended actions or purpose the investment serves for the business (i.e., the asset has reached the end of its useful life, improves safety, etc.).

6.1.5. Alternatives/Options: Describe reasonably viable alternatives and associated analysis (i.e., pro/con, what if, scenario, etc.), where applicable.

6.1.6. Financial Assessment/Cost Estimates: This section should outline a summary of the project cash flows as broken down in the Business Case template.

The risk profile of the estimating technique utilized can be summarized in the AACE Estimate Class table below. In summary, as the maturity level of the project increases the accuracy of the estimate improves, meaning there is less risk in the variability of the scope. The below table may be used as a guideline and or reference for projects greater than $10M in value in estimating project contingencies:

Table 3: AACE Estimation Class (Policy 18R-97 P. 3)

Estimate Class (Indicate AACE class; estimate should achieve a Class 3 when possible)				
Estimate Class	Maturity Level (% of complete definition)	End Usage (typical purpose of estimate)	Methodology (typical estimating method)	Expected Accuracy Range (high/low)
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgement	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored of parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Note. Reprinted from "Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for The Process Industries", by Larry R Dysert AACE International Practice No 18R-97. Retrieved from Rev March 1, 2016.

6.1.7. Schedule: When available a high level logic driven schedule should be produced (via a project planning software tool where applicable) in order to address the key milestone dates.

6.1.8. Risk Assessment: Describe the inherent risk associated with not carrying out this project, including impact on the utility customer. In summary, the Project Managers and Champions are required to exercise professional judgment in the preparation of businesses cases. Information presented and the effort invested in a business case should be tempered against the magnitude of the request. In all cases the document should always seek to provide full and accurate details to support sound decision making.

6.2. Capital Project Expenditure Form

A CPE form is required to be completed in full for all projects under $100,000 as this document triggers the creation of the job within the accounting system.

If a project has a value greater than $100,000 a business case is required to be submitted in conjunction with the CPE. In these instances, the Financial Summary section of the CPE is skipped as these data items will be covered in the business case.

Financial Work Orders/Work Breakdown Schedules) (FWOs/WBS or jobs) are used by the company to track project transactions for items such as timesheets, vendor purchase orders and invoices, accruals, and overhead charges in the accounting system. A new FWO /WBS is typically created once a CPE or business case has been approved by management and before any costs are incurred. The form is available on SharePoint: Click here for FWO/WBS Form.

6.3. Change Orders

Should an approved project require a spend change outside of the original scope of work, a Change Order Form will need to be completed and approved on a two-tier system:

6.3.1. Each change order will require approval subject to the approval limits pursuant to the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group; and

6.3.2. If the cumulative amount of change orders plus the original approved project cost now exceed the approval limit of the initial approver, an approver from the next approval threshold will be required.

i. *For instance, for a $400,000 dollar project the payment approval listing would require an initial approval from Senior Director or Director. If subsequent to the initial approval the cumulative change orders total $110,000, that would bring the total project cost to $510,000 and now also require an approval from the Regional President (LU).*

It is important to note, that in certain circumstances, the Local Commissions requirements will dictate the threshold for the required submission of the Change Order Form, however, it is under the discretion of the project team to manage the change for the project pursuant to the Change Order Form outlined in this document.

6.4. Project Closeout Report

As a vital aspect of any project, closeout is the physical turnover of deliverables from the project team to the operational group. Every project must complete this step irrespective of project size.

All capital projects require a formal close-out to be conducted; multiyear projects do not require annual close out reports. The report will be prepared by the Project Manager in consultation with Functional Leads or regional Subject Matter Experts. Closeouts must be signed off by the Project Sponsor and are due within 90 days of the project completion date.

7. Reporting

The reporting on capital projects is carried through three forms:

1. Monthly Operations Review
2. Monthly Capital Project Reporting
3. Monthly Cash Spend Reporting

7.1. The Monthly Operations Review

On a monthly basis, the Financial Planning & Analysis (FP&A) schedule a meeting to review both regional operating performance and Capital Expenditure variances by region.

7.1.1 Stakeholders Attending the Meeting

- Vice President, Senior Manager, Manager, and the Senior Analyst from FP&A Oakville
- Senior CAPEX Project Analyst, and Director of Capital Planning
- Senior Vice President of Operations
- Regional Presidents (Optional)
- Regional Finance heads

7.1.2 Standing Agenda

The following is the core agenda for each meeting by Regional Presidents and Finance Heads:

1.0 Discussion on Major Regional Based Initiatives

2.0 Discussion on Health and Safety Results (YTD)
- 2.1 Recordable Incident Rate (RIR)
- 2.2 Lost Time Incident Rate (LTIR)
- 2.3 Motor Vehicle Accident Rate (MVAR)

3.0 Financial Performance
- 3.1 Review of Income Statements variances
- 3.2 Distribution Business Group Profit Bridge
- 3.3 Overall Profit by Line of Business and State
- 3.4 Capex variance discussions on overall regional variances

7.2 Monthly Capital Project Reporting

The definition of a major capital project are those projects that have an accrual accounting annual spend of greater than $1M. On a monthly basis a meeting will be held by each regional engineering teams to review project status. Project status will be noted in the Monthly Capital Project Reporting template. The report and resultant meeting will address a brief discussion on risk, cost, and schedule. Key aspects of the report will cover:
Subsequent to the meeting, the engineering teams shall share the

monthly report to the regional accounting teams for inclusion in the monthly management report at the Regional accounting team's discretion.

- Estimate at Completion (EAC)
  - EAC represents the latest contract values, approved or unapproved changed orders, and any potential changes
- Budget: Includes the annual board approved budget as outlined per the budget book
- Actual Cost (AC) including:
  - Year to Date (YTD); and
  - Project to Date (PTD) accrual accounting values
- Color coded matrix outlining status of risk, schedule; and cost.
  - Green - no issues
  - Yellow - potential issues
  - Red - major issues

7.3 Monthly Cash Spend Reporting

On a monthly basis after the Monthly Operations meeting, the capital planning group will prepare a Clarity based report outlining the new accruals forming the beginning and ending accrual by month for the current year. The regional finance heads will be responsible for populating this report with actual cash spend to date along with a project-based estimate to complete highlighting the monthly major project cash payment impacts caused in the respective monthly update.

Appendix A: Capital Project Expenditure Form

Project Name:			
Financial Work Order (FWO):	TBD	**Project ID #:**	#
Requesting Region or Group:		**Date of Request (MM/DD/YY):**	
Project Sponsor:		**Project Start Date:**	
Project Lead:		**Project End Date:**	
Prepared by:		**Requested Capital ($)**	
Planned or Unplanned Projects:	☐ Planned ☒Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☒ Mandated ☐ Growth ☐ Regulatory Supported ☐ Discretionary		

Details of Request

Project description

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?
GUIDANCE: If yes, please detail the specific assets that will be removed: 1. *Original Cost of Plant to be removed (if known):* 2. *What is the replacement cost of the plant being removed (if original cost not known)?* 3. *Original Work Order of Plant to be removed (if known):* 4. *Is the Plant being removed reusable?* 5. *What is the year of original installation of the plant being removed*

What alternatives were evaluated and why were they rejected?

What are the risks and consequences of not approving this expenditure?

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.

Are there other pertinent details that may affect the decision making process?

Complete the Financial Summary table only if:

Financial Summary

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No
Regulatory Lag (Click appropriate box)	☒ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete[5]	☐Fixed or Firm Price ☒Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)			

[5] For Best Practices on estimating project contingencies please see the Capital Policy

Approvals and Signatures[6]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $100,000			Click here to enter a date.
Senior Manager:	Up to $200,000			Click here to enter a date.
Senior Director/Director:	Up to $500,000			Click here to enter a date.
State President / Senior VP / VP:	Up to $2,000,000			Click here to enter a date.
Regional President:	Up to $3,000,000			Click here to enter a date.
Corporate - Sr VP Operations:	Up to $3,500,000			Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $7,500,000			Click here to enter a date.

[6] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Appendix B: Business Case Template

Project Overview			
Project Name:		**Date Prepared:**	Click here to enter a date.
Project ID#:	Click here to enter text.	**Cost Estimate:**	
Project Sponsor:	Click here to enter text.	**Project Start Date:**	Click here to enter a date.
Project Lead:	Click here to enter text.	**Project End Date:**	Click here to enter a date.
Prepared By:	Click here to enter text.	**Planned or Unplanned Projects:**	☐ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☐ Growth ☐ Regulatory Supported ☐ Discretionary		
Project Scope Statement (Insert the scope of work, major deliverables, assumptions, and constraints)			
Background (Insert description of current operational arrangement, and brief history of project & asset)			
Recommendation/Objective (Insert the unique problem this project is looking to resolve)			
Alternatives/Options (Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)			
Financial Assessment/Cost Estimates (Double click embedded excel file to update; include contingency allowance in excel file)			

Next Anticipated Test Year	Click to select a date	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐Less than 6 Months ☐6-12 Months ☐1 to 3 years ☐Greater than 3 years		

Category	Total Already Approved	2018	2019	Beyond 2019	Total
Internal Labour (including labour and travel)	$ -	$ -	$ -	$ -	$ -
Materials (including consumables)	$ -	$ -	$ -	$ -	$ -
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (Including consultants)	$ -	$ -	$ -	$ -	$ -
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *Provide brief explanation on basis of estimate, activities completed to determine costs*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule (List key milestone dates)		
Key Milestone Description	**Forecast Start Date**	**Forecast End Date**
	Click here to enter a date.	Click here to enter a date.

Risk Assessment (Please describe the risk of not completing the project)

Trade Finance (Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)

Approvals and Signatures

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $100,000			Click here to enter a date.
Senior Manager: :	Up to $200,000			Click here to enter a date.
Senior Director/Director:	Up to $500,000			Click here to enter a date.
State President / Senior VP / VP:	Up to $2,000,000			Click here to enter a date.
Regional President:	Up to $3,000,000			Click here to enter a date.
Corporate - Sr VP Operations:	Up to $3,500,000			Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $7,500,000			Click here to enter a date.

Appendix C: Business Case Template

Monthly Capital Project

Reporting For Period End:

		Previous Year			Current Year					Overall Project Metrics										
Budget #	FWO/Project #	A Budget	B Actual Costs	C Variance (B - A)	D Clarity Approved Budget	E Actual Costs	F Estimate to Complete	G Total Estimate at Completion Cost (E+F)	H Projected Variance (E + F - D)	I Total Project Budget	J Total Project Estimate at Completion B + G + [2019 if needed]	K Total Project Variance (J - I)	Project Manager	Percent Complete	Scope	Schedule	Cost	Risks	Quality	Comments
TR-124	*SMAPLE*	*$ 1,000,000*	*$ 1,000,000*	*$ -*	*$ 1,000,000*	*$ 1,000,000*	*$ 50,000*	*$ 1,050,000*	*$ 50,000*	*$ 2,000,000*	*$ 2,050,000*	*$ 50,000*	*John Doe*	*100%*	Scope	Schedule	Cost	Risks	Quality	*E 100% complete, P 100% complete, C 100% complete*
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
				$ -				$ -	$ -	$ -	$ -	$ -			Scope	Schedule	Cost	Risks	Quality	
Regional Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -								

Appendix D: Change Order Form

Project Overview			
Reason for Change: (Please Provide a brief explanation for the cause of the change order)			
Project ID:	Click here to enter text.	**Project Name:**	Click here to enter a date.
Change Order Name:	Click here to enter text.	**Date Prepared:**	Click here to enter a date.
Change Order #:	Click here to enter text.	**Financial Work Order (FWO):**	
Project Sponsor:	Click here to enter text.	**Revised Start Date:**	Click here to enter a date.
Project Lead:	Click here to enter text.	**Revised End Date:**	Click here to enter a date.
Prepared By:	Click here to enter text.	**Change Type**	☐ In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☐ No	**If No is Selected, please specify source of funds**	

Financial Assessment/Cost Estimates (Double click embedded excel file to update; include contingency allowance in excel file)	
Updated Unlevered Internal Rate of Return:	Click here to enter text.
Basis of Current Change Order Amount:	*Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc*) Click here to enter text.

Schedule Impacts (As a result of the Change Order, where applicable, List the Impacts to schedule)		
Baseline Schedule (BL)	**New Forecast (NF)**	**Variance (BL – NF)**
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.

Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.
Click here to enter a date.	Click here to enter a date.	Click here to enter a date.

Approvals and Signatures

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $100,000			Click here to enter a date.
Senior Manager:	Up to $200,000			Click here to enter a date.
Senior Director/Director:	Up to $500,000			Click here to enter a date.
State President / Senior VP / VP:	Up to $2,000,000			Click here to enter a date.
Regional President:	Up to $3,000,000			Click here to enter a date.
Corporate - Sr VP Operations:	Up to $3,500,000			Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $7,500,000			Click here to enter a date.

Appendix E: Project Closeout Report

Requesting Region or Group:		**Date of Closeout (MM/DD/YY):**	Click to select date
Project Name:			
Requesting Region:		**Sponsor** (Name)**:**	
Project Champion:		**Project Champion**	
Project Status	☐In Service ☐Complete ☐ Closed		
Project Start Date:	Click to select date	**Project Completion Date:**	Click to select date
Requested Capital ($)		**Expenditure Included in Approved Budget?**	☐Yes ☐No

Section 1. Approval

Approval of the Project Closeout and Assessment Report indicates an understanding and formal agreement that the project is ready to be closed. By signing this document, each individual agrees all administrative, financial, and logistical aspects of the project should be concluded, executed, and documented as described herein.
Further, by signing this Report, it is accepted that CWIP (FERC Account 107) should be transferred to Utility in Plant Service (FERC Account 101)

Approver Name	Title	Signature	Date
	Project Lead		
	Project Sponsor		
	Operations Manager		
	Accounting Manager		

Section 2. Final Deliverable/Deployment Checklist

Sponsor to respond to each question. For each "no" response, include an issue in Open Issues section.

Item	**Question**	**Response**
2.1	Do you agree that the product and/or service is ready to be deployed?	Yes ☐ No ☐
2.2	Do you agree the product and/or service has sufficiently met the stated business goals and objectives?	Yes ☐ No ☐
2.3	Do you fully understand and agree to accept all operational requirements, operational risks, maintenance costs, and other limitations and/or constraints imposed as a result of ongoing operations of the product and/or service?	Yes ☐ No ☐
2.4	Has the final unitization estimate been provided to Property Accounting?	Yes No
2.5	Do you agree the project should be closed? If no, please explain:	Yes No

Item	Question	Response
	Rate your level of satisfaction with regards to the project outcomes listed below	
2.5	Project Quality	/5
2.6	Product and/or Service Performance	/5
2.7	Scope	/5
2.8	Cost (Budget)	/5
2.9	Schedule	/5

Section 3. Project Documentation Checklist

Project Manager Respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question		Response
3.1	Have project documentation and other items (e.g., Business Case, Project Plan, Charter, Budget Documents, Status Reports) been prepared, collected, filed, and/or disposed?		Yes ☐ No ☐
3.3	Were audits (e.g., project closeout audit) completed and results documented for future reference?		Yes ☐ No ☐
3.4	Identify the storage location for the following project documents items:		
Item	**Document**	**Location (e.g., Google Docs, Webspace)**	**Format**
3.4a	Business Case		☐ Electronic ☐ Manual
3.4b	If available, the Final Project Schedule		☐ Electronic ☐ Manual
3.4c	Budget Documentation and Invoices		☐ Electronic ☐ Manual
3.4d	Status Reports		☐ Electronic ☐ Manual
3.4e	Risks and Issues Log		☐ Electronic ☐ Manual
3.4f	Final deliverable		☐ Electronic ☐ Manual
3.4g	If applicable, verify that final project deliverable for the project is attached or storage location is identified in 3.4.		

Section 4. Project Team
Project Manager to list resources specified in the Project Plan and used by the project.

Name	Role	Type (e.g., Contractor, Employee)

Section 5. Project Lessons Learned

Project Team to identify lessons learned specifically for the project. State the lessons learned in terms of a problem (issue).If available please include a Lesson Learned Log in the attached.. Please summarize the top three issues on the project and the recommended improvements to correct a similar problem in the future.

Problem Statement	Problem Description	References	Recommendation

Section 7. Open Issues

Project Manager and Functional Lead to describe any open issues and plans for resolution within the context of project closeout. Include an open issue for any "no" responses in the Final Product and/or Service Acceptance Checklist and the Project Artifacts Checklist sections.

Issue	Planned Resolution

Section 8. Project Cost Summary

Project Manager and Functional Lead to provide details for the following tables.

Cost Category	1- Budget	2- Actual	3 = 1 -2 Variance
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			

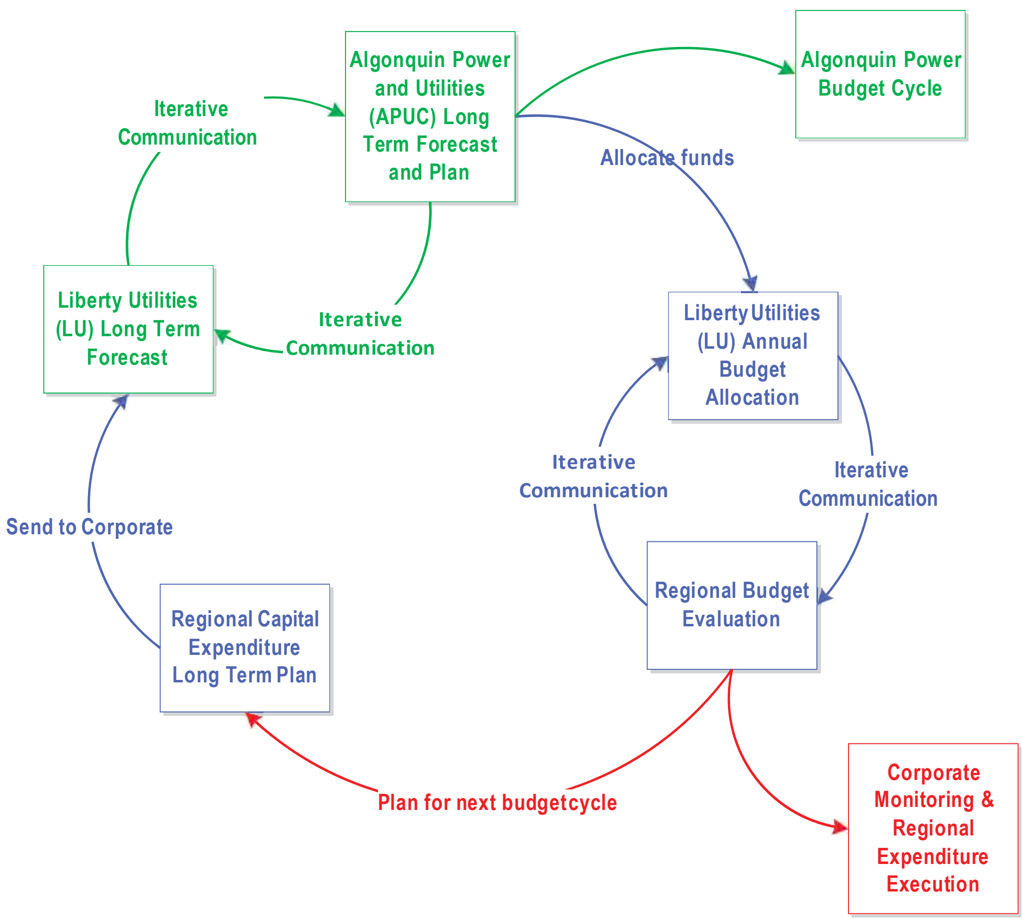
Total Project Costs ($)			

Reasons for Variance	**Impact**
Cause 1	$
Cause 2	$
Cause 3	$

Project Manager to list of all work orders associated with project that should be closed once Close Out Report is accepted.

Registry of All Job Codes (Regional, Corporate, LABs)

Appendix F: Capital Budget Cycle



Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 3

Date Request Received: 7/12/23
Request No. DOE 3-1

Date of Response: 7/26/23
Respondent: Ryan Patnode

REQUEST:

Reference: DOE 2-11 and Attachment DOE 2-11. For each of the projects and plant additions listed below for 2019, 2020, 2021, and 2022 please provide all copies of all documentation required under the Liberty's Policy & Procedures for Capital Expenditures including start dates, Business Cases, Capital Project Expenditure Forms, and Project Close Out Reports:

Capital Projects GSE CY 2019		Budget	Actual	Variance
8830-1901	01663 GS Storm Program Proj	$100,000	$349,695	-$249,695
8830-1912	Dist-Damage & Failure Blanket	$700,000	$1,127,737	-$427,737
8830-1991	01659 Granite St Meter Purchases	$230,000	$952,029	-$722,029
8830-1965	Rockingham Substation Trans.	$200,000	$301,229	-$101,229
8830-1964	Rockingham Substation	$200,000	$276,462	-$76,462
8830-1925	IT Systems & Equipment	$125,000	$509,011	-$384,011
8830-1927	IT Systems Allocations	$ 50,000	$ 77,273	- $ 27,273
8830-1949	NN ERR/Pockets of Poor Perf.	$100,000	$217,007	-$117,007
8830-1969	GSE Mall Road-Street Lights	$0	$421,587	-$421,587
8830-1993	GSE Facilities Capital Impr.	$550,000	$373,268	$176,732
8830-UNALL	Finance Unalloc Burden	$0	$309,595	-$309,595

Capital Projects GSE CY 2020		Budget	Actual	Variance
8830-1944	Golden Rock Substation	$ 300,000	$ 311,738	-$ 11,738
8830-1958	Install Service to Tuscan Village	$ 900,000	$2,362,438	-$ 1,462,438
8830-1965	Rockingham Substation Trans.	$1,750,000	$1,804,061	-$ 54,061
8830-2037	GSE-Dist New Bus-Resid	$1,000,000	$1,400,390	-$ 400,390
8830-1960	Golden Rock Underground	$ 100,000	$ 120,997	-$ 20,997
8830-1964	Rockingham Substation	$ 750,000	$ 824,447	-$ 74,447
8830-2046	Bare Conductor Replacement	$1,700,000	$2,183,426	-$ 483,426
8830-2027	IT Systems & Equipment Blanket	$ 125,000	$ 183,976	-$ 58,976
8830-2072	SAP Ariba GSE Portion to Pay	$ 164,143	$ 251	$ 163,892
8830-2093	GSE Facilities Capital Improv.	$ 750,000	$ 559,460	$ 190,540

Docket No. DE 23-039 Request No. DOE 3-1

8830-2095	Tuscan Village EV Chargers	$ 210,000	$ 21,838	$ 188,162
8830-UNALLOC	OH Finance Unalloc Burden	$ 384,069	$ 843,160	-$ 459,091
8830-2052	Golden Rock Dist. Automation	$ 125,000	$ 224,795	-$ 99,795

Capital Projects GSE CY 2021		Budget	Actual	Variance
8830-1958	Install Service to Tuscan Village	$1,000,000	$812,956	$ 187,044
8830-1965	Rockingham Substation Trans.	$6,000,000	$6,372,658	-$ 372,658
8830-2069	Golden Rock Feeder 19L2	$2,100,000	$1,383,849	$ 716,151
8830-1964	Rockingham Substation	$7,000,000	$10,238,907	-$3,238,907
8830-2074	Rockingham Dist. Feeders	$1,500,000	$1,219,683	$ 280,317
8830-2095	Tuscan Village EV Charges	$ 150,000	$ 354,768	-$ 204,768
8830-2193	GSE Facilities Capital Improv.	$ 368,000	$ 93,889	$ 274,111
8830-2197	Add-on to Garage in Salem	$ 700,000	$ 667,641	$ 32,359
8830-UNALLOC	OH Finance Unalloc Burden	$ 193,063	$ 631,619	-$ 438,556

Capital Projects GSE CY 2022		Budget	Actual	Variance
8830-2212	Dist. Damage & Failure Blanket	$1,415,500	$1,932,718	-$ 517,218
8830-2291	01659 Granite St Meter Purchases	$ 500,000	$ 907,558	-$ 407,558
8830-1944	Golden Rock Substation	$ 600,000	$ 961,820	-$ 361,820
8830-1958	Install Service to Tuscan Village	$1,000,000	$ 134,806	$ 865,194
8830-1965	Rockingham Substation Trans.	$9,000,000	$7,071,538	$1,928,462
8830-2069	Golden Rock Dist. Feeder 19L4	$ 0	$ 310,595	-$ 310,595
8830-1964	Rockingham Substation	$ 500,000	$ 460,015	$ 39,985
8830-2074	Rockingham Dist. Feeders	$ 400,000	$ 231,691	$ 168,309
8830-2207	GSE-Dist-Genl Equip Blanket	$ 50,000	$ 545,727	-$ 495,727
8830-2227	IT Systems Allocations-Corporate	$ 50,000	$1,243,499	-$1,193,499
8830-2239	IE-NN URD Cable Replacement	$ 500,000	$ 509,233	-$ 9,233
8830-2285	AMI	$ 700,000	$ 2,501	$ 697,499
8830-2286	2022 Cloud-Analytics-NH	$ 700,000	$ 334,588	$ 365,412
8830-2290	Transportation Fleet & Equip.	$2,000,000	$2,404,403	-$ 404,403
8830-2293	GSE Facilities Capital Improv.	$ 600,000	$ 961,477	-$ 361,477
8830-2299	SAP Placeholder-GSE	$19,116,666	$13,550,995	$5,565,671
8830-22XX	IEEE Membership	$ 155,000	$ 207,186	-$ 52,186
8830-UNALLOC	OH Finance Unalloc Burden	$ 191,500	$2,730,627	-$2,539,127

RESPONSE:

Attachment 23-039 DOE 3-1.xlsx contains the list of projects identified above with an indication of the documentation included for each project. In reviewing the original response to DOE 2-11 the Company identified an erroneous calculation of the variance between actual and budget and has provided a revised calculation in column (i).

Please note, Corporate IT allocation projects are individually approved via the IT in-take process described in Liberty's capital policy. The Finance unallocated burdens project is a project that initially receives construction work in progress charges before the charges are allocated to individual jobs. The project is not placed in service until they are allocated out of the unallocated project to individual projects, therefore there is no documentation provided for those placeholder projects.

In gathering the requested historical documentation for the projects selected, the Company was unable to locate complete documentation for eleven projects identified in the table below. The Company has since completed that documentation and current executives with appropriate authority recently signed the documents indicating that those executives are aware of the documents and the associated projects, that they acknowledge their responsibility for those projects, and that they stand behind those projects as appropriate for recovery in this docket.

ProjectID	Year	Project Description	Document
8830-1901	2019	01663 GS Storm Program Proj	Change Order
8830-1912	2019	Dist-Damage&Failure Blanket	Change Order
8830-1965	2019	Rockingham Substation Transmission Supply	Change Order
8830-1964	2019	Rockingham Substation	Change Order, Project Closeout Report
8830-1969	2019	GSE Mall Road - Street Lights	Capital Project Business Case, Capital Project Expenditure Form
8830-1993	2019	GSE Facilities Capital Improvements	Capital Project Business Case, Capital Project Expenditure Form
8830-2052	2020	Golden Rock Distribution Automation Controller	Capital Project Expenditure Form
8830-1965	2021	Rockingham Substation Transmission Supply	Change Order
8830-2212	2022	Dist-Damage&Failure Blanket	Change Order
8830-2291	2022	01659 Granite St Meter Purchases	Change Order, Project Closeout Report
8830-22XX	2022	IEEE-Membership	Change Order

Please see the following attachments containing the project documentation requested for the selected projects:

- Attachment 23-039 DOE 3-1.1.zip contains projected documentation for the 2019 projects.
- Attachment 23-039 DOE 3-1.2.zip contains projected documentation for the 2020 projects.
- Attachment 23-039 DOE 3-1.3.zip contains projected documentation for the 2021 projects.
- Attachment 23-039 DOE 3-1.4.zip contains projected documentation for the 2022 projects.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23 Date of Response: 9/15/23
Request No. DOE 6-13 Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-1 for the following projects:

2019 Capital Projects, UNALL Finance Unalloc Burden	$309,595
2020 Capital Projects, UNALLOC OH Finance Unalloc Burden	$843,160
2021 Capital Projects, UNALLOC OH Finance Unalloc Burden	$631,619
2022 Capital Projects, UNALLOC OH Finance Unalloc Burden	$2,730,627

a. Given that these are annual blanket projects involving significant expenditures, why is not possible to writeup a Business Case and Capital Project Expenditure form for this project category as required under Liberty's Capital Expenditure Planning policy provided in Attachment DOE 2-12?

b. If not documented, then how does Liberty formulate a budget and obtain management approval for this project?

c. What records are available for DOE to review to verify how the funds were allocated? Please provide those records.

RESPONSE:

a. The expenditures associated with the unallocated project on its own do not fall under the capital project definitions of new or extending the life of an "asset." Although the expenditures in the unallocated projects are related to the support of capital projects, it is not until these work-in-progress costs are allocated to an asset-defined project that they fall under the capital approval policy.

b. Individual projects are approved by capital business cases and capital expense forms. Typically, a line item is included in the overall Capital budget which is reserved for the unallocated project expenditures that will be incurred over the course of the fiscal year. The unallocated expenditures are not approved as an individual project because the cost does not remain in this project. The costs are allocated to sanctioned projects, which are authorized to include the burden cost as part of the overall project cost. Approval of the unallocated project would be a duplicate approval of costs.

Docket No. DE 23-039 Request No. DOE 6-13

c. A sample of August 2022 journal entries for July's population was provided. See Attachment 23-039 DOE 6-13.zip.

1. FILTER ON COST ELEMENT 2

(BH) 8/31/2022 - validated filtering of pivot below

(BH) 8/31/2022 all charges have posting date in month of July
(BH) 8/31/2022 no jobs have been cancelled or transferred to Plant

Sum of Cost Code Actual Cost TTD														
WS Job Number	WS Job Name	WS Project	WS Descrip	Divisions	Cost Eleme	Account Number String	Transactio	GL Posting Date	Document Source	Cancelled	Transfer to Plant	WS Inactive	Total
301938-01070	1 Medical Center Dr Lebanon	8830-193	GSE Dist.	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/1/2022	IV	1/1/1900	1/1/1900	No	84.3
302137-01304	392 Hill Rd Alstead	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	2885.34
302137-01304	392 Hill Rd Alstead	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	IVARCT0	7/25/2022	GJ	1/1/1900	1/1/1900	No	-0.52
302138-01080	425 MIRACLE MILE, LEBANON	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	5567.3
8830-STO	Materials Burden	8830-UN	Finance	8830-CAI	2	8830-2-0000-10-1618-1070	8830 Cle	7/31/2022	GL	1/1/1900	1/1/1900	No	27711.87
302212-01012	Slavin Dr Pelham	8830-211	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/25/2022	IV	1/1/1900	1/1/1900	No	140.36
302213-01001	P11-2 Bank St Ext Lebanon	8830-211	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	IVARCT0	7/25/2022	GJ	1/1/1900	1/1/1900	No	2.1
302124-01004	SALEM LED CONV PH 4 - 346 LTS	8830-222	LED Stre	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/7/2022	IV	1/1/1900	1/1/1900	No	7912
302124-01004	SALEM LED CONV PH 4 - 346 LTS	8830-222	LED Stre	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	18197.6
302237-01071	60 County Rd Walpole NH	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	198
302138-01085	401 MAIN ST, SALEM	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	2228.91
302138-01085	401 MAIN ST, SALEM	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	IVARCT0	7/25/2022	GJ	1/1/1900	1/1/1900	No	5.6
302237-01057	17 Cottonwood Ln Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	148.61
302113-01023	Lancaster Farm Salem	8830-211	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/7/2022	IV	1/1/1900	1/1/1900	No	5009.79
302137-01449	21 Farm House Lane Pelham	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/27/2022	IV	1/1/1900	1/1/1900	No	4005.64
302213-01014	P29 River Rd Walpole	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	454.68
302213-01022	Stevens Rd Hanover	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/1/2022	IV	1/1/1900	1/1/1900	No	472.36
302223-01003	NH Route 4A Enfield	8830-222	GSE Distr	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/25/2022	IV	1/1/1900	1/1/1900	No	863.26
302237-01084	19 Cottonwood Ln Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	250.9
302237-01088	2 Lorraine Ave Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	204
302237-01097	18 Cottonwood Ln Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	279.85
302237-01099	18 Bush Hill Rd Pelham	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	1100.57
302237-01137	10 COTTAGE LN, CANAAN	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	2055.79
302037-01711	14 BASSWOOD RD	8830-203	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	82.99
302137-01146	48 Lewin Rd Enfield	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	85
302210-01033	136 GOODHUE RD, DERRY	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	249.41
302210-01034	TRAILER HOME LN, SALEM	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/27/2022	IV	1/1/1900	1/1/1900	No	833.2
302210-01034	TRAILER HOME LN, SALEM	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	739.6
302221-01005	53 Mountainview Drive Enfield	8830-222	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	2361.82
302237-01120	277 Lawrence Rd Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	482.5
302237-01120	277 Lawrence Rd Salem	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	IVARCT0	7/25/2022	GJ	1/1/1900	1/1/1900	No	27.5
302237-01165	19 Wheeler Ave charlestown NEW	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/25/2022	IV	1/1/1900	1/1/1900	No	275.4
302237-01169	55 Trescott Rd Etna NH 03750	8830-223	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/1/2022	IV	1/1/1900	1/1/1900	No	127.9
302212-01006	Old Drewsville Rd Walpole	8830-211	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	230.85
302219-01003	P4 HAVERHILL RD, SALEM	8830-211	IE-NN Di	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	312.96
302137-01432	27 Mulberry Rd Salem	8830-213	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	59.15
302210-01021	180 MARSH RD, PELHAM	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	1624.72
302210-01031	P93 Route 4 Enfield	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	223.5
302210-01035	P62 Rt 4, Enfield	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	173.43
302210-01052	P5 NEWCOMB FIELD PKWY, PELHAM	8830-221	GSE-Dist	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	405.4
302212-01132	P6/P7 HILLARD RD, ACWORTH	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	37.38
302212-01138	P14 Rockingham Rd, Salem	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	108
302212-01140	P9 Peabody Rd, Pelham	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/7/2022	IV	1/1/1900	1/1/1900	No	205.72
302212-01141	PAD3-4 PATRDGE LN, ETNA	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	303.55
302212-01142	P145, Main St, Walpole	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/19/2022	IV	1/1/1900	1/1/1900	No	803.78
302212-01143	Xfmr 5-9, Mall Rd, Salem	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	76.18
302212-01144	SG 4-MH5, Mall Rd, Salem	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/27/2022	IV	1/1/1900	1/1/1900	No	4115.2
302212-01145	156-1 NORTH MAIN STREET SALEM	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	102
302212-01145	156-1 NORTH MAIN STREET SALEM	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	109.2
302212-01146	143 Rt 135, Monroe	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	93.5
302212-01147	P41 Currier Rd, PELHAM	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/20/2022	IV	1/1/1900	1/1/1900	No	116.46
302212-01149	P18 Dutton Rd, Pelham	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/12/2022	IV	1/1/1900	1/1/1900	No	104.35
302212-01152	MACDONALD DR, HANOVER	8830-221	Dist-Dam	8830-CAI	2	8830-2-0000-10-1618-1070	(blank)	7/14/2022	IV	1/1/1900	1/1/1900	No	146.85

302212-01153	**P5,P19-21, HIGH ST, ALSTEAD**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/14/2022	**IV**	1/1/1900	**1/1/1900**	No	1058.13
302212-01157	**Grist Mill Hill Rd Canaan**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/14/2022	**IV**	1/1/1900	**1/1/1900**	No	434.71
302212-01160	**P96 RT 12A, PLAINFIELD**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/25/2022	**IV**	1/1/1900	**1/1/1900**	No	850.18
302212-01161	**20 LADY LANE SALEM P6-1**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/12/2022	**IV**	1/1/1900	**1/1/1900**	No	93.5
302212-01163	**PAD3-4, PARTRIDGE RD, ETNA**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/25/2022	**IV**	1/1/1900	**1/1/1900**	No	136.35
302212-01164	**Great Hollow Rd P23-1, Hanover**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/14/2022	**IV**	1/1/1900	**1/1/1900**	No	674.76
302212-01165	**P35 CROSS ST, SALEM**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	622.68
302212-01167	**P11 SAWMILL RD, PELHAM**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	72.8
302212-01172	**38 BRADY AVE SALEM NH**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/27/2022	**IV**	1/1/1900	**1/1/1900**	No	127.4
302212-01175	**P87-1 SHORE DRIVE SALEM NH**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/27/2022	**IV**	1/1/1900	**1/1/1900**	No	439.1
302212-01176	**P12 CAR MAR LN SALEM NH**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/27/2022	**IV**	1/1/1900	**1/1/1900**	No	346.18
302212-01177	**P89-96 Old Keene Rd Walpole**	8830-22:	**Dist-Dan**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/25/2022	**IV**	1/1/1900	**1/1/1900**	No	65.91
302223-01010	**P17 Cross St, Salem DG**	8830-22:	**GSE Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	131
302237-01012	**9 Charles St Salem**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	148.5
302237-01023	**9 SATURN WAY UNIT 29, PELHAM**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/12/2022	**IV**	1/1/1900	**1/1/1900**	No	50.18
302237-01040	**76 Valley Hill Rd Pelham**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/27/2022	**IV**	1/1/1900	**1/1/1900**	No	214.5
302237-01186	**21 COTTONWOOD LN, SALEM**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	167.28
302237-01191	**16 OLD KEENE RD, WALPOLE**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/14/2022	**IV**	1/1/1900	**1/1/1900**	No	48.82
302237-01230	**14 FOREMAN LN, PELHAM**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	381.48
302238-01047	**8 PUMPING STATION RD, SALEM**	8830-22:	**GSE-Dist**	8830-CAI	**2**	8830-2-0000-10-1618-1070	**(blank)**	7/20/2022	**IV**	1/1/1900	**1/1/1900**	No	210
Grand Total													**100,669.27** ¦ (BH) 8/31/2022

System: 8/31/2022 3:58:58 PM
User Date: 8/31/2022

Liberty Utilities New Hampshir
GENERAL POSTING JOURNAL
Multicurrency Management

User ID: RHILTON

* Voided Journal Entry
# Intercompany Journal Entry

Batch: 8830-STO

Approved: No	Batch Total Actual: US$33,031.10	Batch Total Control:	US$0.00
Approved by:	Trx Total Actual: 1	Trx Total Control:	0
Approval Date:			

Journal Entry	Transaction Type	Transaction Date	Reversing Date	Source Document	Transaction Reference	Audit Trail Code	Reversing Audit Trail Code
Currency ID	Rate Type ID	Exchange Rate					
1,834,260 Z-US$	Standard	8/1/2022		GJ	Alloc 8830STO-0722	GLTRX00123502	

Account	Description	Exchange Rate	Functional/Originating Debit	Credit
8830-2-0000-10-1618-1070	Construction Work In Progress		US$5,910.48	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$19.08	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$653.04	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$1,260.28	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$31.77	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$0.48	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$44.82	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$505.83	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$33.64	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$1,134.08	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$906.76	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$102.93	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$106.93	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$195.42	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$56.80	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$46.18	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$63.35	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$249.14	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$465.37	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$18.79	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$19.24	

* Voided Journal Entry
\# Intercompany Journal Entry

8830-2-0000-10-1618-1070	Construction Work In Progress	US$56.46
8830-2-0000-10-1618-1070	Construction Work In Progress	US$356.04
8830-2-0000-10-1618-1070	Construction Work In Progress	US$534.65
8830-2-0000-10-1618-1070	Construction Work In Progress	US$115.45
8830-2-0000-10-1618-1070	Construction Work In Progress	US$62.34
8830-2-0000-10-1618-1070	Construction Work In Progress	US$28.95
8830-2-0000-10-1618-1070	Construction Work In Progress	US$52.26
8830-2-0000-10-1618-1070	Construction Work In Progress	US$70.85
8830-2-0000-10-1618-1070	Construction Work In Progress	US$13.39
8830-2-0000-10-1618-1070	Construction Work In Progress	US$367.79
8830-2-0000-10-1618-1070	Construction Work In Progress	US$50.59
8830-2-0000-10-1618-1070	Construction Work In Progress	US$39.26
8830-2-0000-10-1618-1070	Construction Work In Progress	US$91.77
8830-2-0000-10-1618-1070	Construction Work In Progress	US$8.46
8830-2-0000-10-1618-1070	Construction Work In Progress	US$24.45
8830-2-0000-10-1618-1070	Construction Work In Progress	US$46.57
8830-2-0000-10-1618-1070	Construction Work In Progress	US$68.72
8830-2-0000-10-1618-1070	Construction Work In Progress	US$181.95
8830-2-0000-10-1618-1070	Construction Work In Progress	US$17.25
8830-2-0000-10-1618-1070	Construction Work In Progress	US$931.57
8830-2-0000-10-1618-1070	Construction Work In Progress	US$47.81
8830-2-0000-10-1618-1070	Construction Work In Progress	US$21.17
8830-2-0000-10-1618-1070	Construction Work In Progress	US$26.36
8830-2-0000-10-1618-1070	Construction Work In Progress	US$23.62
8830-2-0000-10-1618-1070	Construction Work In Progress	US$33.24
8830-2-0000-10-1618-1070	Construction Work In Progress	US$239.53
8830-2-0000-10-1618-1070	Construction Work In Progress	US$98.41
8830-2-0000-10-1618-1070	Construction Work In Progress	US$192.46
8830-2-0000-10-1618-1070	Construction Work In Progress	US$21.17
8830-2-0000-10-1618-1070	Construction Work In Progress	US$30.87
8830-2-0000-10-1618-1070	Construction Work In Progress	US$152.75
8830-2-0000-10-1618-1070	Construction Work In Progress	US$140.96

* Voided Journal Entry
\# Intercompany Journal Entry

8830-2-0000-10-1618-1070	Construction Work In Progress	US$16.48	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$28.84	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$99.40	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$78.37	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$14.92	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$29.65	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$33.62	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$11.36	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$48.56	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$37.87	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$11.05	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$86.36	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$47.54	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$16,515.55
Total Distributions: 67	Functional Totals:	US$16,515.55	US$16,515.55
	Originating Totals:		

Total Journal Entries: 1

System: 8/31/2022 9:03:40 AM
User Date: 8/31/2022

Liberty Utilities New Hampshir
GENERAL TRANSACTION EDIT LIST
Multicurrency Management

User ID: JCALVAGNA

Batch: 8830-STO

Approved:	No	Batch Total Actual:	US$33,031.10	Batch Total Control:	US$0.00
Approved By:		Trx Total Actual:	1	Trx Total Control:	0
Approval Date:					

APPROVED
By RHilton at 3:58 pm, Aug 31, 2022

(BH) evidence of review is saved in the Excel file

Intercompany Journal Entry

Journal Entry	Transaction Type	Transaction Date	Reversing Date	Source Document	Transaction Reference
Currency ID	Rate Type ID	Exchange Rate			
1,834,260	Standard	8/1/2022		GJ	Alloc 8830STO-0722
Z-US$					

Account	Description	Exchange Rate	Functional/Originating Debit	Credit
8830-2-0000-10-1618-1070	Construction Work In Progress		US$5,910.48	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$19.08	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$653.04	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$1,260.28	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$31.77	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$0.48	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$44.82	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$505.83	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$33.64	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$1,134.08	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$906.76	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$102.93	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$106.93	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$195.42	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$56.80	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$46.18	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$63.35	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$249.14	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$465.37	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$18.79	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$19.24	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$56.46	

Intercompany Journal Entry

8830-2-0000-10-1618-1070	Construction Work In Progress	US$356.04
8830-2-0000-10-1618-1070	Construction Work In Progress	US$534.65
8830-2-0000-10-1618-1070	Construction Work In Progress	US$115.45
8830-2-0000-10-1618-1070	Construction Work In Progress	US$62.34
8830-2-0000-10-1618-1070	Construction Work In Progress	US$28.95
8830-2-0000-10-1618-1070	Construction Work In Progress	US$52.26
8830-2-0000-10-1618-1070	Construction Work In Progress	US$70.85
8830-2-0000-10-1618-1070	Construction Work In Progress	US$13.39
8830-2-0000-10-1618-1070	Construction Work In Progress	US$367.79
8830-2-0000-10-1618-1070	Construction Work In Progress	US$50.59
8830-2-0000-10-1618-1070	Construction Work In Progress	US$39.26
8830-2-0000-10-1618-1070	Construction Work In Progress	US$91.77
8830-2-0000-10-1618-1070	Construction Work In Progress	US$8.46
8830-2-0000-10-1618-1070	Construction Work In Progress	US$24.45
8830-2-0000-10-1618-1070	Construction Work In Progress	US$46.57
8830-2-0000-10-1618-1070	Construction Work In Progress	US$68.72
8830-2-0000-10-1618-1070	Construction Work In Progress	US$181.95
8830-2-0000-10-1618-1070	Construction Work In Progress	US$17.25
8830-2-0000-10-1618-1070	Construction Work In Progress	US$931.57
8830-2-0000-10-1618-1070	Construction Work In Progress	US$47.81
8830-2-0000-10-1618-1070	Construction Work In Progress	US$21.17
8830-2-0000-10-1618-1070	Construction Work In Progress	US$26.36
8830-2-0000-10-1618-1070	Construction Work In Progress	US$23.62
8830-2-0000-10-1618-1070	Construction Work In Progress	US$33.24
8830-2-0000-10-1618-1070	Construction Work In Progress	US$239.53
8830-2-0000-10-1618-1070	Construction Work In Progress	US$98.41
8830-2-0000-10-1618-1070	Construction Work In Progress	US$192.46
8830-2-0000-10-1618-1070	Construction Work In Progress	US$21.17
8830-2-0000-10-1618-1070	Construction Work In Progress	US$30.87
8830-2-0000-10-1618-1070	Construction Work In Progress	US$152.75
8830-2-0000-10-1618-1070	Construction Work In Progress	US$140.96
8830-2-0000-10-1618-1070	Construction Work In Progress	US$16.48

Intercompany Journal Entry

8830-2-0000-10-1618-1070	Construction Work In Progress	US$28.84	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$99.40	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$78.37	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$14.92	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$29.65	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$33.62	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$11.36	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$48.56	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$37.87	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$11.05	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$86.36	
8830-2-0000-10-1618-1070	Construction Work In Progress	US$47.54	
8830-2-0000-10-1618-1070	Construction Work In Progress		US$16,515.55

Total Distributions:	67	Functional Total:	US$16,515.55	US$16,515.55
		Originating Totals:		

Total Journal Entries: 1

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Audit Requests
2019-2022 project 8830-Unallocated Burden

Date Request Received: 8/14/23 Date of Response: 9/8/23
Request No. AR 85 Respondent: Ryan Patnode

REQUEST:

The Company response to the Staff Data Request 3-1 for the sample project 8830-Unalocated Burden indicates the Company was unable to provide any specific project backup documentation for the project. The response indicates the unallocated jobs are still in CWIP and have not been unitized to plant in service until they get allocated to the specific project/job that are going to be unitized to plant. Please indicate by year why the variances are so much higher compared to the budgeted cost. Please indicate why for 2019-2022 the Company is spending $4,515,002 on projects that are supposed to be allocated to plant in service accounts 101/106 as that is what DOE Regulatory Staff was specifically trying to review. Please explain and provide details that indicates the Company is not charging for overheads/burdens twice for this project and other individual projects. Please explain how the capitalized fleet/equipment burdens are calculated in the $4,515,002 project costs that were unitized to plant in service.

(a) Line	(b) ProjectID	(c) Year	(d) Project Description	(e) Included in St	(f) Budget	(g) Actual	(h) = (f) - (g) Variance ($) (over)/unde	(i) = (h) / (f) % Variance (over)/und	(j) Capital Project Business Case	(k) Capital Project Expenditure Form	(l) Change Order	(m) Project Closeout Report
11	8830-UNALLOC OH	2019	Finance Unalloc Burden	N	$ -	$ 309,595	$ (309,595)		N/A	N/A	N/A	N/A
24	8830-UNALLOC OH	2020	Finance Unalloc Burden	N	$ 384,069	$ 843,160	$ (459,091)	-120%	N/A	N/A	N/A	N/A
35	8830-UNALLOC OH	2021	Finance Unalloc Burden	N	$ 193,063	$ 631,619	$ (438,556)	-227%	N/A	N/A	N/A	N/A
53	8830-UNALLOC OH	2022	Finance Unalloc Burden	N	$ 191,500	$ 2,730,627	$ (2,539,127)	-1326%	N/A	N/A	N/A	N/A
					$ 768,632	$ 4,515,002						

RESPONSE:

The unallocated burden project is a financial vehicle for burdened/ overhead to hold CWIP costs before being allocated to actual construction/ purchasing jobs. Each month there is a crediting entry from the unallocated project to that month's eligible jobs. Allocation rates are established by forecasting the overhead/burden cost divided by forecasted eligible capital spend. Eligible capital cost as it is defined in the attached "burden summary." See Attachment 23-039 AR 85.1. Eligible spending includes direct labor, materials, Vouchers, and outside services.

The New Hampshire Overhead Procedure, Attachment 23-039 AR 85.2, explains how the rates are updated each quarter and how the journal entries to the unallocated project are processed each month. The $4,515,002 spent referenced is just a view of the cost remaining in the project at year-end. The cost remaining at year-end will be part of the next year's cost allocation. There is constant movement month to month on the project spend. The debit for overhead/burden cost, Docket No. DE 23-039 Request No. AR 85

Credit out to individual jobs based on calculated rates and eligible spend. See Attachment 23-039 AR 85.2, sections 6.5 and 6.6, for examples of monthly journal entries.

Prior to SAP, all overhead/burden cost was initially charged to CWIP charged to the unallocated project. In SAP beginning in October 2022, labor burdens follow labor charges directly to individual projects.

Liberty Utilities WATER | GAS | ELECTRIC		2845 BRISTOL CIRCLE, OAKVILLE, ONTARIO L6H 7H7		
General Procedure		Proc. #:	**2100-700-100-0005**	
Description	**New Hampshire Overhead Procedure**	Revision #:	0	Page: 1 of 5

1.0 PURPOSE

The purpose of this document is to establish a methodology to be used for allocating capital overhead cost to individual capital jobs. Capital cost not directly related to individual jobs requires a method for these cost to be allocated to individual jobs. This procedure documents how allocation rates are established and how monthly entries are executed.

2.0 SCOPE

This document applies to New Hampshire operating companies. To be applied to all capital overhead cost allocated to jobs.

3.0 DEFINITIONS

Labor Burden Cost- Budgeted Employee benefit cost, employee pensions, property insurance, injuries and damages, IT-related cost, IT software depreciation, rent and back office non-labor cost. Divided by budgeted payroll (excluding incentives/time not worked/ back office labor). Cost to be allocated

Stores- Capital Material cost to be allocated

Fleet- Vehicle utilization cost to be allocated

Overhead Cost- In-direct capital labor, Opex/Capex Labor, Burden's on in-direct and Opex/Capex labor, Fleet burden correlative to In-direct labor. Oakville allocated capital cost. Cost to be allocated

4.0 REFERENCES

Labor burden rate- approved
Overhead quarterly forecast calculation

5.0 RESPONSIBILITY

Roles and responsibilities are outlined in the "Procedure" section of this document

6.0 PROCEDURE

6.1 Overview

6.1.1 Burdened and overhead rates are established periodical per rate.

6.1.2 Burdened labor rate is applied each month to current month capital labor.

6.1.3 Fleet, Stores and Overhead rate cost are charged throughout the year in each individual burden job. Each month a per established rate is applied to eligible capital spend.

6.1.4 Burden rates are established and approve by Finance. Overhead rates are established and approved by Operation each quarter.

6.2 Burdens and Overheads

6.2.1 **Labor Burden Rate**. This rate is established by the finance Manager/Director and is approved by the finance Vice President. The burden rate is applied to current month capital labor cost.

6.2.2 **Fleet Rate.** The fleet rate is established each quarter by the annual forecasted capital fleet cost divided by the annual forecasted capital labor cost. Fleet overhead rate is allocated each month to current month capital labor cost.

6.2.3 **Stores Rate.** The stores rate is established each quarter by the annual forecasted capital stores cost divided by the annual forecasted capital material cost. Stores overhead rate is allocated each month to current month capital material cost.

6.2.4 **Overhead Rate.** The overhead rate is established each quarter by the forecasted capital overhead cost divided by the forecast capital labor, material and vendor cost. The Overhead rate is allocated each month to current month capital labor,material and vendor cost.

6.2.5 **Monthly Entries.** Each month, all applicate cost is allocated by the current rate to individual jobs based on their current month eligible capital spend.

6.3 Calculation of Rates.

6.3.1 Labor Burden Cost. The burden rate is established by each utility. This rate is approved by finance.

$$\text{Labor Burden} = \frac{\text{Employee benefits, Pensions, Property insurance and damages, IT-related cost, Rent, Back office non-labor}}{\text{Budgeted payroll (Excluding incentives/ time not worked/ Back office labor)}}$$

6.3.2 Fleet Rate. The forecast fleet cost is determined by each utility and is usually based on budgeted amounts, historical cost and current spend run rate.

$$\text{Fleet Rate} = \frac{\text{Annual forecast capital fleet cost}}{\text{Annual forecast capital labor cost}}$$

6.3.3 Stores Rate. The forecast stores cost is determined by each utility and is usually based on budgeted amounts, historical cost and current spend run rate.

$$\text{Stores Rate} = \frac{\text{Annual forecast capital stores cost}}{\text{Annual forecast capital materials cost}}$$

6.3.4 Overhead Rate. The forecast overhead cost is determined by each utility and is usually based on budgeted amounts, historical cost and current spend run rate.

$$\text{Overhead Rate} = \frac{\text{Annual forecast capital in-direct labor cost, Annual forecast capital Opex/Capex labor cost, Annual forecast capital overhead in-direct, Opex/Capex, Burdened cost, Annual forecast capital overhead fleet cost, Annual forecast capital Oakville cost}}{\text{Annual forecast capital labor, materials and vendor cost}}$$

Liberty Utilities WATER | GAS | ELECTRIC		2845 BRISTOL CIRCLE, OAKVILLE, ONTARIO L6H 7H7		
General Procedure		Proc. #:	**2100-700-100-0005**	
Description	**New Hampshire Overhead Procedure**	Revision #:	0	Page: 4 of 5

6.4 Quarterly review of rate calculation.

6.4.1 **Review.** To ensure rates remain relevant on a quarterly basis the Fleet, Stores and Overhead rate shall be reviewed and adjusted accordingly per the rate calculation documented in section 6.2. The updated quarterly rate will be published and then applied in the preceding quarter.

6.5 General Accounting Journal Entries.

6.5.1 Direct Capital Labor Burden Entry
Credit: Account: 9220 -Admin expense transferred
Debit: Account: 107- Construction work in progress- Job BRD

6.5.2 Opex/Capex labor and Burden Entry
Credit: Account: 9220- Admin expense transferred
Debit: Account: 107-Construction work in progress- Job LAB

6.5.3 Fleet Capital
Credit: 184-Transporation Expense
Debit: 107-Construction work in progress- Job BRD

6.5.4 Stores
Credit: 183- Stores Expense Undistriubted
Debit:107-Construction work in progress- Job STO

6.5.5 LU Corpoarte LABS
Credit: 922- LU,APUC, LABS Capitalized
Debit: 107-Construction work in progress- Job LU

6.6 Plant Accounting Journal Entries.

6.6.1 Labor Burden Entry-
Credit Account: 107-Construction work in progress- Job BRD
Debit Account:107 Construction work in progress- Current month eligible jobs.

6.6.2 Fleet
Credit Account: 107-Construction work in progress- Job BRD
Debit Account:107 Construction work in progress- Current month eligible jobs.

6.6.3 Stores
Credit Account: 107-Construction work in progress- Job STO
Debit Account:107 Construction work in progress- Current month eligible jobs.

6.6.4 Overhead
Credit Account: 107-Construction work in progress- Job LAB & Job LU
Debit Account:107 Construction work in progress- Current month eligible jobs

7.0 APPENDICES

None

8.0 REVISION HISTORY

Date	Rev #	Description	Sponsor/Lead Person
1/31/20	3		Ryan Patnode

9.0 APPROVAL AUTHORITY

Date	Title or Position	Signature

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23	Date of Response: 11/20/23
Request No: DOE TS 2-41	Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-1 and DOE 6-13, Attachment DOE 6-13.zip for the following projects:

2019 Capital Projects, UNALL Finance Unalloc Burden	$309,595
2020 Capital Projects, UNALLOC OH Finance Unalloc Burden	$843,160
2021 Capital Projects, UNALLOC OH Finance Unalloc Burden	$631,619
2022 Capital Projects, UNALLOC OH Finance Unalloc Burden	$2,730,627

a. Confirm that these projects serve as a form of suspension account where unallocated CWIP is collected and retained until allocated to related projects.

b. How often are the costs allocated to related projects? Monthly? Annually?

c. Reference Attachment DOE 6-13.zip. Given that project numbers and associated job numbers are identified and recorded in the accounting, please explain why these costs cannot be allocated to the related projects at the time they are incurred. Also, explain the differences between the tabs in the Excel spreadsheets and what they represent.\

d. Explain why some CWIP charges are not allocated and unitized to related projects at year-end. Shouldn't the year-end balance be zero? If some projects are not completed by year-end, why should that make a difference?

RESPONSE:

a. Confirmed. These projects serve as conduits to construction work-in-progress costs until the costs are allocated to eligible capital work-in-progress jobs.

b. An allocation process is run monthly for eligible capital work-in-progress jobs.

c. The eligible CWIP spending fluctuates between the calendar months. Allocating the cost out in full each month would adequately burden certain projects due to the calendar year's spending timing. Attachment 8830 Burden Allocation Data July 2022 provides the eligible CWIP spend for the sampled amount. The individual JE#1834xxx attachments detail the specific burden/overhead allocations. The JE # 1834xxx is the actual journal entry output. The "alloc 8830-XXX" tab provides the view calculation of the eligible job population multiplied by the quarter rates. The subsequent tabs provide the backup for the eligible CWIP spend.

d. The overhead allocation percentages post-2019 are forecasted based on the CWIP forecast for the fiscal year. Prior to the implementation of SAP in 2022, the manual journal entry for eligible capital was performed a month lagged, resulting in a carryover between years. It is coupled with the overhead allocation forecast based on expected eligible CWIP spend. The predicted allocation percentage is not affected if a project is not completed by year end; only CWIP spending impacts the calculation. The allocation is impacted when projects underspend or spending shifts between years because the cost will be allocated in future months.

PURCHASE AND SALE AGREEMENT

This Agreement is dated this ___ day of December, 2017 (the "Effective Date"), between Rock Acquisition, LLC, a New Hampshire limited liability company, having an address of 2352 Main St., Suite 201, Concord, MA 01742 (the "Seller"), and Liberty Utilities (Granite State Electric) Corp., a New Hampshire corporation having a mailing address of 15 Buttrick Road, Londonderry, NH 03053 (the "Buyer").

Reference is made to the following facts:

A. Seller owns approximately 120 acres of land on Route 28 in Salem, New Hampshire, being developed as a retail and residential mixed-use project under the name of "Tuscan Village" (the "Tuscan Village Project").

B. Buyer desires to purchase approximately 1.4 acres of land (the "Real Estate"), which is part of the Tuscan Village Project, as shown on the plan attached hereto as Exhibit A, together with an easement over Tuscan Village Project for the right to access the Real Estate. The Real Estate, together with (i) all rights, privileges and easements appurtenant to the Real Estate and owned by Seller; and (ll) all improvements, on or within the Real Estate shall be collectively referred to herein as the "Property".

C. Buyer intends to seek subdivision approval from the Town of Salem to subdivide the Real Estate from the remainder of the Tuscan Village Project, to purchase the Property from Seller, and to construct an electrical substation thereon (the "Substation"), subject to the terms and conditions herein.

NOW, THEREFORE, for and in consideration of good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller agrees to sell and Buyer agrees to buy the Property for the sum and upon the terms and conditions as follows:

1. Sale and Purchase. Seller shall sell and Buyer shall purchase, in fee simple absolute and subject to the terms and conditions herein, the Property.

2. Purchase Price. The purchase price (the "Purchase Price") for the Property shall be One Million Five Hundred Thousand and 00/100 Dollars ($1,500,000.00) ("Purchase Price"), payable as follows:

(a) Buyer has paid a deposit of One Hundred Fifty Thousand Dollars ($150,000.00) (the "Deposit"). The Deposit shall be held in escrow by Hinckley, Allen & Snyder LLP (the "Escrow Agent") in an interest-bearing account and shall be applied or disbursed in accordance with the terms of this Agreement.

(b) Subject to the adjustments and prorations provided elsewhere in this Agreement, the balance of One Million Three Hundred Fifty Thousand 00/100 Dollars ($1,350,000.00) shall be paid by the Buyer to the Seller on the date of the closing of this sale (the "Closing") in immediately available funds by certified check or federal wire transfer.

3. Time of Closing. The parties agree to close on the date which is thirty (30) days after the expiration of the Permit Period, unless otherwise mutually agreed upon by the parties. The Closing shall occur at the offices of Seller's counsel in New Hampshire, or at such other place mutually agreed upon by the parties, at a time mutually convenient to the parties.

4. Warranties and Representations.

(a) Seller represents to the Buyer that: (i) Seller has marketable and insurable title to the Property; (ii) Seller is not a "foreign person" within the meaning of Section 1455, et. seq. of the Internal Revenue Code of 1986 as amended, or any regulations promulgated thereunder; (iii) Seller has the power and authority to enter into and perform its obligations under this Agreement and the execution, delivery and performance of this Agreement have been duly authorized by all necessary limited liability company actions, and (iv) there is no suit, action (legal or administrative), arbitration or other proceeding or any nature pending or to the best of Seller's knowledge, threatened against the Property, or against the Seller and relating to the Property.

(b) Buyer represents to the Seller that (i) the Buyer has the power and authority to enter into and perform its obligations under this Agreement; and (ii) the execution, delivery and performance of this Agreement have been duly authorized by all necessary actions.

5. Condition of Property. Buyer understands and agrees that, other than with respect to Seller's obligations hereunder to be satisfied prior to Closing, and Seller's post-closing construction obligations pursuant to Paragraph 20(b) hereof, Seller has not made and does not make any representations or warranties as to the physical condition, title, or any other matter or thing affecting or relating to the Property and Buyer hereby expressly acknowledges that no such representations or warranties have been made or are implied. Buyer agrees to take the Property "AS IS, WHERE IS" on the Closing Date with all faults in its then physical condition and Seller expressly disclaims any representations or warranties of title, merchantability, usage or fitness for any particular purpose.

6. Title and Deed. At the Closing, Seller shall convey to Buyer or its nominee by Warranty Deed (the "Deed") fee simple good and clear record, marketable and insurable title to the Property, free of all liens, agreements, leases, restrictions, parties in possession, mortgages and encumbrances except: (i) provisions of building and zoning laws in effect on the Closing Date; (ii) real property taxes for the then current year which are not yet due and payable on the Closing Date; (iii) any matters of record existing as of the date of this Agreement provided that the same do not materially interfere with the use

of the Property for the Substation in the reasonable discretion of Buyer (collectively, the "Permitted Exceptions").

Notwithstanding the foregoing, unless Buyer notifies Seller in writing prior to the expiration of Buyer's "Due Diligence Period" (defined in Section 7, below) of any respect in which title to the Property does not conform with the requirements of this Agreement, then Buyer shall be treated as having waived any right thereafter to assert that title to the Property is not of the quality required hereby, but such waiver shall apply only with respect to defects existing as of the date of the expiration of Buyer's Inspection Period.

If Buyer notifies Seller in writing as aforesaid of any manner in which Seller's title does not conform with the requirements of this Agreement (the "Buyer's Title Objections"), then Seller shall notify Buyer within five (5) business days thereafter, whether Seller will attempt to cure such Title Objections. Seller's failure to give notice within said five (5) business day period shall be deemed an election not to cure said Title Objections. If Seller elects to cure said Title Objections as aforesaid, Seller shall, for a period of time (not to exceed 30 days), to use diligent and good faith efforts to remove and remedy same. If, at the expiration of such thirty (30) day period, Seller despite such diligent and good faith efforts shall have failed to remove and remedy same, then, at Buyer's option, the Deposit shall be forthwith returned to Buyer, this Agreement shall become null and void, and the parties hereto shall have no further rights and obligations hereunder. Notwithstanding the foregoing, Seller shall be obligated to remove, at Seller's sole cost and expense (i) any mortgage affecting the Real Estate; (ii) any monetary lien affecting the Real Estate; and (iii) any real estate taxes or assessments affecting the Real Estate (collectively the "Monetary Liens"), provided that Seller shall be entitled to use the sale proceeds to remove the Monetary Liens.

7. Due Diligence/Investigations.

(a) For a period commencing on the Effective Date and expiring at 5:00 p.m. Eastern Standard Time forty five (45) days thereafter ("the Due Diligence Period"), Buyer shall have the right to perform its due diligence review, in such a manner as Buyer determines, of the condition of the Property, including without limitation, title, environmental condition, planning and zoning laws, and physical characteristics relating to the Property, at Buyer's sole expense, to determine the suitability of the Property for the Substation. If Buyer determines during such time, within its reasonable discretion, that the condition of the Property or any other matter related to the Property or Buyer's intended use thereof is not acceptable, then Buyer shall have the right to terminate this Agreement, by giving written notice of termination to Seller, upon which (i) the Buyer shall deliver to Seller all other reports, engineering data, plans, studies and other similar materials related to the Property prepared for or generated by Buyer in connection with its due diligence review of the Property; (ii) the Deposit shall be refunded to the Buyer; (iii) this Agreement shall become null and void; and (iv) the parties shall have no further rights or obligations hereunder. If this Agreement is not terminated as aforesaid, the Deposit shall become nonrefundable, except in the event Buyer does not obtain the Permits as set forth in Section 8.

(b) During the Due Diligence Period, Seller shall provide Buyer or its authorized representatives reasonable access to the Property, as Buyer may from time to time reasonably request to conduct, at Buyer's sole expense, all such reviews, studies, tests and the like which are reasonably appropriate in connection with the inspections authorized by Subsection (a) above. Seller agrees to reasonably cooperate with Buyer in its due diligence and, within five (5) business days after the Effective Date, will provide to Buyer copies of all reports, permits, approvals and other information and materials related to the condition of the Property, including but not limited to, site assessments, environmental assessments, surveys, existing or draft subdivision or site plans, soil studies and all other data pertaining to the physical condition or physical nature of the Property, to the extent such materials are in Seller's possession (the "Seller's Due Diligence Materials"). Seller's Due Diligence Materials will be provided by Seller without representation or warranty as to accuracy or completeness. If Seller's Due Diligence Materials are not timely delivered to Buyer within this five (5) business day deadline, the Due Diligence Period shall be extended one (1) day for each day such materials are delivered late.

(c) Buyer shall be responsible for ensuring that any part of Property affected by such investigation is restored to as near as possible its original condition. Buyer's investigation shall be conducted in a manner so as to minimize interference or disruption of any on-going business activities at the Property and on the Tuscan Village Project. Furthermore, Buyer shall also notify Seller at least two (2) days in advance of any proposed investigations requiring entry upon the Property. Seller may impose such reasonable requirements on Buyer as it may reasonably elect in order to assure that the Property is not damaged. As a condition to allowing Buyer or any of its representatives access to the Property, Buyer or its representatives shall provide Seller with evidence of comprehensive general liability insurance in an amount not less than Two Million Dollars ($2,000,000.00) naming Seller as an additional insured on such policy. Without limiting the foregoing, Buyer hereby agrees to indemnify, defend and hold Seller harmless from and against any and all claims, suits, obligations, liabilities, damages, costs and expenses (including without limitation reasonable attorney's fees) for physical injury to the Property or for injury to persons or property arising out of any of the provisions of this Section 7 or any acts or omissions of Buyer or any of its representatives in performing Buyer's due diligence review hereunder. This Section 7(c) shall survive the expiration or termination of this Agreement.

(d) Hazardous Materials, Environmental Laws. Buyer's inspection during the Due Diligence Period shall include, but shall not be limited to, investigations of the physical condition thereof and to determine the status of the Property with respect to geotechnical matters and Hazardous Materials (as hereinafter defined) and compliance with applicable Environmental Laws (hereinafter defined). Notwithstanding anything to the contrary contained herein, Buyer's right to conduct such inspections and tests shall not include the right to conduct any invasive environmental testing, and neither Buyer nor any of its agents, consultants or contractors shall perform any borings, well drilling, cut samples or similar procedures without the prior written approval of Seller. "Hazardous Materials" means asbestos, urea formaldehyde, polychlorinated biphenyls, nuclear fuel or materials, radioactive materials, explosives, known carcinogens, petroleum products and by products (including crude oil or any fraction thereof), and any pollutant, contaminant, chemical, material or substance defined as hazardous or as a pollutant or a contaminant in, or the use, manufacture, generation, storage, treatment, transportation, release or disposal of which is regulated by, any Environmental Law. "Environmental Law" means any federal, state, county, municipal, local or other statute, ordinance or regulation that relates to or deals with the protection of the environment or wildlife and/or human health and safety, including all regulations promulgated by a regulatory body pursuant to any such statute, ordinance, or regulation, including the Comprehensive Environmental Response and Liability Act of 1980, as amended, 42 U.S.C. Section 9601 et seq., the Resource Conservation and Recovery Act, as amended, 42 U.S.C. Section 6901, et seq., the Federal Water Pollution Control Act, as amended, 33 U.S.C. Section 1251 et seq., the Clean Air Act, as amended, 42 U.S.C. Section 7401 et seq. and any applicable local law or the laws of the State of New Hampshire and any regulations promulgated thereunder (collectively, the "Environmental Laws").

8. Approvals. The Buyer shall have a period of one hundred twenty (120) days after the expiration of the Due Diligence Period (the "Permit Period") to obtain, at Buyer's sole cost and expense, all necessary final and unappealable governmental licenses, permits, and approvals to construct the Substation on the Property (the "Permits"). Buyer shall be responsible to obtain any and all necessary permits and approvals, including subdivision approval, at Buyer's sole cost and expense, except that if such permits and approvals are conditioned upon construction or installation of improvements as part of Seller's Tuscan Village Project, the cost of such improvements shall be Seller's responsibility, as further set forth in Section 20(c). Buyer shall use diligent and good faith efforts to obtain all required Permits. Seller agrees to cooperate with Buyer in seeking said Permits, provided that Seller shall not be required to incur any costs or expenses in connection therewith. Seller hereby authorizes Buyer during the term of this Agreement to apply for and sign applications for any Permits and shall execute the authorization letter attached hereto as Exhibit B simultaneously with the execution of this Agreement.

In the event the Buyer, despite its diligent and good faith efforts, is not able to secure the Permits within the Permit Period, with all appeal periods expired with no appeals filed or with any appeals dismissed or determined with finality in favor of Buyer, either party may, if it so elects, terminate this Agreement, upon which the Deposit shall be refunded to Buyer.

9. Condemnation. If, prior to the Closing, all or any part of the Property shall be condemned by governmental or other lawful authority such that, in Buyer's reasonable judgment, its contemplated use of the Property is materially, adversely affected, Buyer shall have the option of (a) completing the purchase in accordance with the terms of this Agreement, in which event all condemnation proceeds or claims thereof relating to the Property, if any, shall be assigned to Buyer or (b) canceling this Agreement, in which event any Deposit paid by Buyer shall be forthwith returned to Buyer and this Agreement shall be terminated with neither party having any rights or obligations hereunder.

10. Taxes and Assessments. Real property taxes, water and sewer charges, utility costs, if any, shall be prorated and adjusted on a per diem basis as of the date of Closing using the most recently available assessment, invoice, meter reading or billing. Taxes due and payable for all prior years shall be paid, by Seller, on or before the Closing. If the Closing shall occur before the tax rate is fixed for the then-current year, the apportionment of taxes shall be upon the basis of the tax rate for the preceding year applied to the latest assessed valuation, with the proration to be adjusted between the parties based on actual taxes for the year in which Closing occurs at the time such actual taxes are determined. If as of the date of Closing no separate assessment has been assigned to the Property then, for purposes of prorating, the assessed value for the Property will be that percentage of the overall assessment of the land valuation component of the property from which the Property has been subdivided as the acreage of the Property bears to the total acreage of the unsubdivided property prior to subdivision.

11. Transfer Tax. The expense and cost of all state and local documentary, revenue stamps, or other transfer taxes, if any, relating to the sale of the Property shall be divided evenly between the parties on the date of Closing consistent with New Hampshire conveyancing practice. Both parties agree to execute any tax returns required to be filed in connection with any such taxes.

12. Default by Buyer. If the Buyer shall fail to close the transaction contemplated hereby, or shall default in any other obligation of Buyer hereunder for a period of more than ten (10) days after written notice of such default by Seller, the Deposit made hereunder shall be paid by the Escrow Agent to the Seller as liquidated damages as Seller's sole remedy, either in equity or law. The parties acknowledge that such liquidated damages are a fair and reasonable measure of Seller's potential damages from Buyer's failure to fulfill Buyer's agreements herein, and that such liquidated damages do not and will not constitute a penalty. The parties acknowledge and agree that Seller has no adequate measure of damages in the event of Buyer's breach of or default under this Agreement because it is impossible to compute exactly the damages or losses which would accrue to Seller in such event. Therefore, the parties have taken these facts into account in setting the amount of the deposits made hereunder, and hereby agree that: (i) such Deposit is a reasonable forecast and approximation of such actual damages and losses which would accrue to Seller in the event of Buyer's default hereunder, and which could result from Seller's inability to resell the Property for the same agreed purchase price due to any number of presently undeterminable factors, including, but not by way of limitation, compensation to Seller for removing the Property from the market and reimbursement for costs and expenses (including attorney's fees) incurred by Seller; and (ii) the Deposit represents a reasonable amount for such damages and losses and not a penalty against the Buyer. In such an event this Agreement shall become null and void and the parties shall have no further rights or obligations hereunder.

13. Default by Seller. If, Seller shall default in the performance of any of its obligations hereunder, Buyer shall, have the right either (i) to terminate this Agreement without further liability hereunder, in which event the Deposit shall be forthwith returned to

Buyer and the parties shall have no further rights of obligations hereunder or (ii) to pursue a suit for specific performance.

14. Brokerage Fees. Seller and Buyer represent and warrant to each other that no brokerage fees or real estate commissions are or shall be due or owing in connection with this transaction or in any way with respect to the Property. Seller agrees to defend, indemnify, and hold Buyer harmless from any claims, costs, judgments, or liabilities of any kind advanced by persons claiming real estate brokerage fees through Seller. Buyer agrees to defend, indemnify and hold Seller harmless from any claims, costs, judgments, or liabilities of any kind advanced by persons claiming real estate brokerage fees through Buyer. The indemnities set forth in this Paragraph 14 shall survive Closing

15. Conditions Precedent to Buyer's Obligation to Purchase the Real Estate. The obligation of the Buyer to purchase the Property under this Agreement is expressly conditional and contingent upon all of the following:

(a) receipt of marketable and insurable title to and possession of the Property simultaneously with the Closing in the condition required by this Agreement, subject to the Permitted Exceptions;

(b) all of Seller's warranties and representations set forth in Paragraph 4 hereof being true as of the Closing, and Seller shall have fully satisfied all covenants hereunder required to be satisfied before the Closing;

(c) no eminent domain proceeding pending against the Property or any portion thereof;

(d) there being no material adverse change in the condition of the Property from its condition as of the date of the expiration of the Due Diligence Period; and

(e) receipt or waiver of the Permits.

These conditions and Seller obligations are for the benefit of Buyer and any one or more of such conditions or obligations (collectively, the "Buyer Conditions Precedent to Closing") may be waived by Buyer in its sole discretion. If any one of the Buyer Conditions Precedent to Closing are not met, Buyer may terminate this Agreement by giving written notice to Seller and receive a refund of the Deposit.

16. Conditions Precedent to Seller's Obligation to Sell the Property. The obligation of the Seller to sell the Property under this Agreement is expressly conditional and contingent upon receipt of the full Purchase Price from the Buyer for the Property at the Closing.

17. Notices. All notices and other communications required or permitted to be given hereunder shall be in writing and shall be (i) mailed by certified or registered mail,

postage prepaid, or (ii) sent overnight mail by a recognized national delivery service, or (iii) faxed or emailed (with confirming hard copy mailed by first class mail) addressed as follows or to such other addresses as the parties may designate in writing from time to time:

If to Seller:	Rock Acquisition, LLC 2352 Main St., Suite 201 Concord, MA 01742 Tel: (603) 912-5467 Email: tbean@tuscanbrands.com
With a copy to:	Hinckley, Allen & Snyder LLP 650 Elm St., Suite 500 Manchester, NH 03101 Attn: John H. Sokul, Jr. Tel: (603) 225-4334 Email: jsokul@hinckleyallen.com
If to Buyer:	Liberty Utilities 15 Buttrick Road Londonderry, NH 03053 Attn: Jill Fitzpatrick Tel: (603) 216-952-2999 Email: Jill.Fitzpatrick@libertyutilities.com
With a copy to:	Liberty Utilities 15 Buttrick Road Londonderry, NH 03053 Attn: Michael J. Sheehan Tel: (603) 216-335 Email: Michael.Sheehan@libertyutilities.com

18. Closing Costs. Notwithstanding anything to the contrary contained herein, the Closing costs shall be paid as follows:

By Buyer:

(a) title examination and title insurance premium
(b) one-half of the State real estate transfer tax
(c) recording fees
(d) its own legal fees

By Seller:

(a) cost of preparing the Deed
(b) one-half of the State real estate transfer tax

(c) cost of obtaining and recording all title clearing documents, if any
(d) its own legal fees

19. Documents to be Delivered at Closing. At the Closing, the Seller and Buyer shall execute, acknowledge and deliver all documents required to effectuate the transaction contemplated by this Agreement.

20. Construction Obligations. The following special obligations shall apply to the transaction and shall survive the Closing:

(a) Buyer shall construct, at Buyer's sole cost and expense, the Substation which will provide adequate electrical service to the Tuscan Village Project as generally shown on the conceptual master plan, a copy of which is attached hereto as Exhibit C, and according to the service requirements timetable attached hereto as Exhibit D. Buyer represents and warrants that the electrical system supplying electricity to the Tuscan Village Project, including the Substation, will be sufficient to serve the Seller's proposed development as and when needed per Exhibit D.

(b) Within thirty days following execution of this Agreement, Seller shall provide, at Seller's sole cost and expense, gravel, unpaved (but reasonable) access to the Real Estate in the general location shown on Exhibit E. The access will be paved by Seller following the Closing as and when Seller's Tuscan Village project is fully built out.

(c) Seller shall reserve in the deed to Buyer a slope/grading easement in the area labeled "Proposed 15' 0" grading easement" on Exhibit F. Seller shall be responsible, at its sole cost and expense, for any grading and related improvements within the slope/grading easement. Buyer shall be responsible, at its sole cost and expense, to construct a screening fence around the substation and for all other improvements on the Property.

21. Time of Essence. Time is expressly declared to be of the essence of this Agreement.

22. Headings. The headings to the Sections hereof have been inserted for convenience of reference only and shall in no way modify or restrict any provisions hereof or be used to construe any such provisions.

23. Modifications. The terms of this Agreement may not be amended, waived or terminated orally, but only by an instrument in writing signed by both Seller and Buyer.

24. Successors. This Agreement may not be assigned by the Buyer without Seller's prior written consent, which shall not be unreasonably withheld.

25. Deposit and Escrow Funds.

(a) The Deposits made hereunder shall be held in escrow by Hinckley, Allen & Snyder LLP as escrow agent, subject to the terms of this Agreement and shall be duly accounted for at the Closing. The Deposit shall be held in a federally insured, interest-bearing, money market escrow account. In the event that Buyer or Seller sends notice to Escrow Agent certifying to Escrow Agent that it is entitled to receive the Deposit pursuant to the terms of this Agreement (other than at the Closing), Escrow Agent shall forward a copy of such certification to the other party (pursuant to the notice provisions of Paragraph 17 hereof). If Escrow Agent does not receive an objection from such party to such certification within fifteen (15) days after the date of such notice, Escrow Agent may disburse all such amounts to the certifying party. If Escrow Agent receives an objection or receives conflicting demands, Escrow Agent shall have the right to do either of the following: (i) interplead the Deposit into a court of competent jurisdiction in Hillsborough County, New Hampshire (the cost of doing so, up to a maximum of $1,000, to be deducted from the Deposit) and the parties shall thereafter be free to pursue their rights at law or in equity with respect to the disbursement of the Deposit and the Escrow Agent shall be fully released and discharged from its duties and obligations under this Agreement; or (ii) resign and transfer the Deposit to a replacement escrow agent reasonably satisfactory to Buyer and Seller. Upon the transfer of Deposit to such replacement escrow agent, the Escrow Agent shall thereupon be fully released and discharged from all obligations to further perform any and all duties or obligations imposed upon it by this Agreement.

(b) The Escrow Agent shall incur no liability hereunder whatsoever, except in the event of its willful misconduct or gross negligence. The other parties hereto, jointly and severally, agree to defend and indemnify the Escrow Agent against all reasonable costs, obligations and liabilities suffered by it for which it may be claimed to be liable hereunder, except for that occasioned by its willful misconduct or gross negligence. The indemnity provided in the preceding sentence shall survive any termination of this Agreement. The fees of the Escrow Agent and costs incurred by it in performing its duties hereunder shall be shared equally by the parties.

(c) The Buyer acknowledges and understands that the Escrow Agent is Seller's attorney in this transaction. In the event of any dispute between the Buyer and the Seller arising out of this Agreement, the Buyer agrees that the Escrow Agent may represent the Seller in connection with that dispute provided that Escrow Agent also proceeds in accordance with (i) or (ii) of Paragraph (a), above. The Buyer agrees that in the event of any such dispute and provided that the Escrow Agent proceeds in accordance with (i) or (ii) of Paragraph (a) above, it will not object to the Escrow Agent's representation of the Seller in such dispute because of any potential or actual conflict of interest arising due to the Escrow Agent's role as Escrow Agent under the terms of this Agreement.

26. Counterparts. The Agreement may be signed by the parties in counterparts.

27. Cooperation. The parties agree to cooperate with each other in good faith

and in all reasonable respects to cause the transactions contemplated by this Agreement to be consummated in accordance with the terms of this Agreement and in allowing each party to fulfill its obligations and covenants contained in this Agreement, including, without limitation, each parties' permitting and construction activities.

28. Entire Agreement. This Agreement contains the entire agreement between Seller and Buyer, and there are no other terms, conditions, undertakings, promises, statements, or representations, express or implied, concerning the sale and other undertakings contemplated by this Agreement.

29. Title Standards. With respect to the conveyance of the property contemplated by this Agreement, any title matter which is the subject of a title standard of the New Hampshire Bar Association Title Examination Standards at the time for delivery of the deed shall be governed by said title standard to the extent applicable and not inconsistent with any provision of this Agreement.

30. Drafting Party. Buyer and Seller acknowledge that each of them and their counsel have had an opportunity to review this Agreement and that this Agreement will not be construed against either party merely because its counsel has prepared it.

31. Force Majeure. Notwithstanding anything to the contrary contained in this Agreement the parties' respective construction obligations shall be extended by one day for each day that completion is delayed due to wars, acts of God, fire, insurrection, and riots, winter conditions or strikes that prevent normal progress of construction, provided that written notice of such delay is delivered to the other party within fifteen days after the delay.

[Signature blocks on next page]

IN WITNESS WHEREOF, the parties have executed this Agreement in duplicate as of the day and year first above written.

SELLER: ROCK ACQUISTION, LLC

By: ______________________________
Name: Joseph P. Faro
Its: Managing Member

BUYER: LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.

By: ______________________________
Name: Susan L. Fleck
Its: President

ESCROW AGENT: HINCKLEY, ALLEN & SNYDER LLP

By______________________________
Name: John H. Sokul
Its: Partner

EXHIBIT B – Authorization Letter

To Whom It May Concern:

Rock Acquisition, LLC (the "Owner") is the owner of the property located at 71 Rockingham Park Blvd., Salem, New Hampshire (the "Property"). The Owner hereby authorizes Liberty Utilities and/or its agents to execute, submit and prosecute applications and any applicable materials to the Town of Salem boards, commissions, agencies and the like (including, without limitation, zoning boards, planning boards and the Selectmen) on behalf of the Owner, for the purpose of obtaining municipal permits and approvals for the construction of an electrical substation on the Property.

Rock Acquisition, LLC

By: ____________________

Name: Joseph R. Faro

Title: Managing Member

Duly authorized

IN WITNESS WHEREOF, the parties have executed this Agreement in duplicate as of the day and year first above written.

SELLER: ROCK ACQUISTION, LLC

By: ______________________________
Name:
Its:

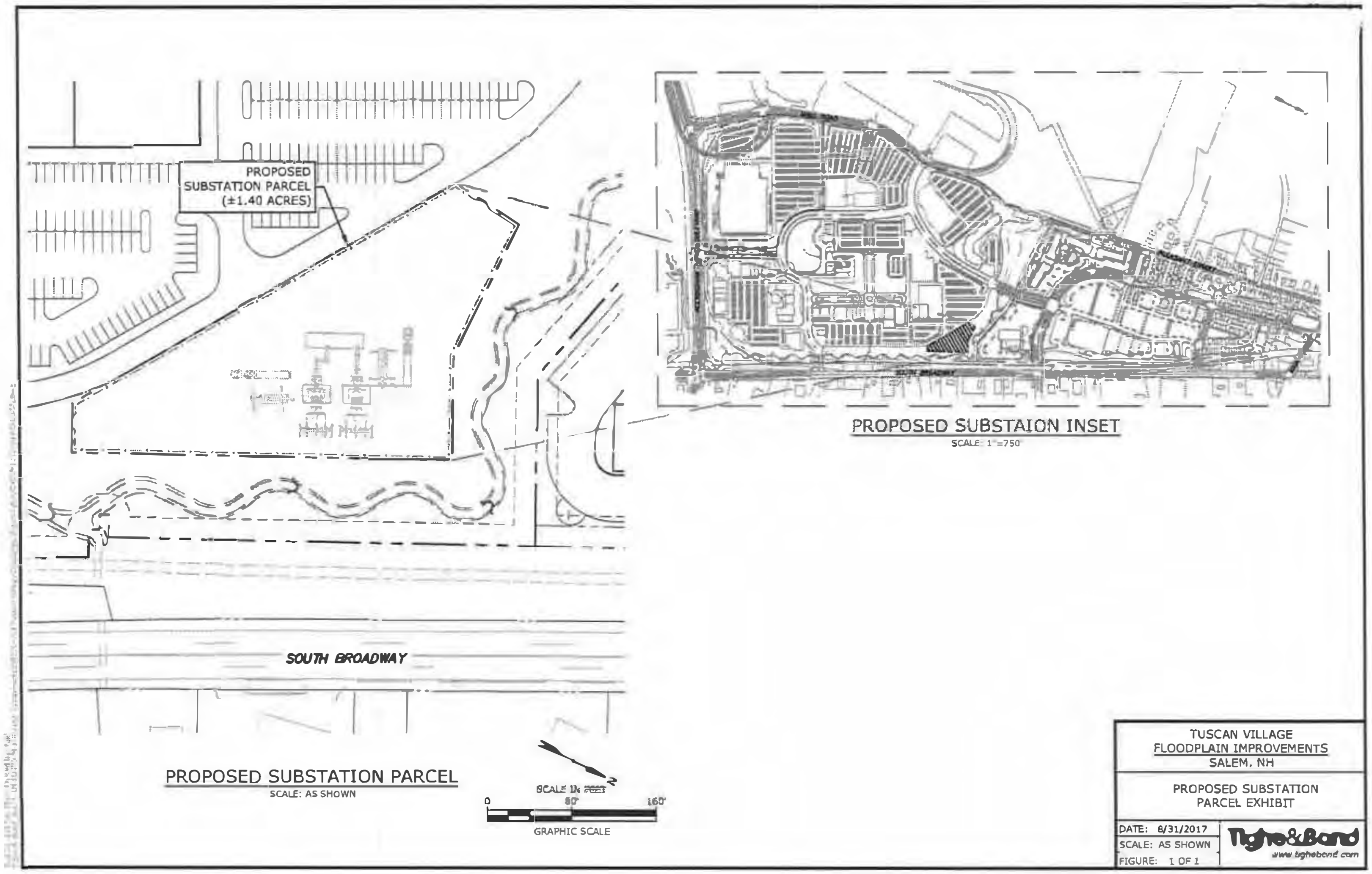
BUYER: LIBERTY UTILITIES (GRANITE STATE ELECTRIC) P.

By: ______________________________
Name: Susan L. Fleck
Its: President

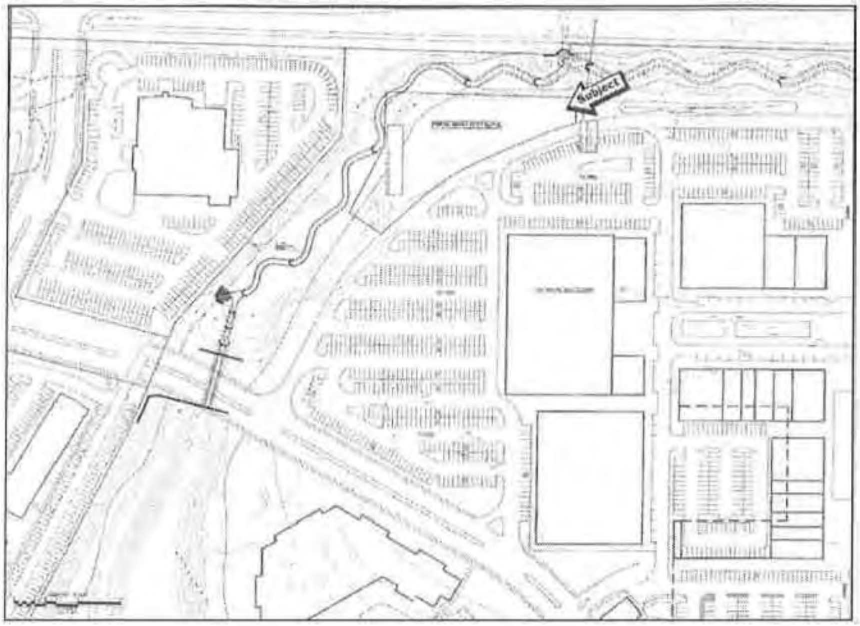
ESCROW AGENT: HINCKLEY, ALLEN & SNYDER LLP

By______________________________
Name: John H. Sokul
Its: Partner

EXHIBIT A – Plan Showing Real Estate


PROPOSED
SUBSTATION PARCEL
(±1.40 ACRES)
SOUTH BROADWAY
PROPOSED SUBSTATION PARCEL
SCALE: AS SHOWN
SCALE IN FEET
0
80'
160'
GRAPHIC SCALE
PROPOSED SUBSTAION INSET
SCALE: 1"=750'
TUSCAN VILLAGE
FLOODPLAIN IMPROVEMENTS
SALEM, NH
PROPOSED SUBSTATION
PARCEL EXHIBIT
DATE: 8/31/2017
SCALE: AS SHOWN
FIGURE: 1 OF 1
Tighe&Bond
www.tighebond.com

REAL ESTATE APPRAISAL REPORT



1.23± ACRES TUSCAN VILLAGE
SALEM, NEW HAMPSHIRE

OWNED BY
ROCK ACQUISITION, LLC

CAA FILE NO. 60.0491

PREPARED FOR
ATTORNEY MICHAEL SHEEHAN
SENIOR COUNCIL
LIBERTY UTILITIES

AS OF
JULY 13, 2017

Crafts Appraisal Associates, Ltd.
4 Bell Hill Road • Bedford, NH 03110 • 603 472-2444 • fax 603 472-9856 •
Email admin@craftsappraisal.com

Crafts Appraisal Associates, Ltd.

Real Estate Appraisals

July 27, 2017

Attorney Michael Sheehan
Senior Council
Liberty Utilities
15 Buttrick Road
Londonderry, NH 03053

Re: **REAL ESTATE APPRAISAL REPORT OF**
1.23± ACRE PARCEL
TUSCAN VILLAGE
SALEM, NEW HAMPSHIRE
OWNED BY ROCK ACQUISITION, LLC
CAA PROJECT FILE NUMBER 60.0491

Dear Attorney Sheehan,

I have inspected the above-captioned property in order to report my opinion of the Market Value of the fee simple estate as of July 13, 2017. The subject of this report consists of a hypothetical 1.23± acres that will be dedicated to Liberty Utilities' installation of a substation to service the larger Tuscan Village Development on the former Rockingham Park. Exhibits provided by Liberty Utilities indicate this parcel to be on the eastern portion of the larger site near North Broadway. It shows it being on the perimeter of a parking area that will service a commercial portion of the development that is yet to be developed.

The purpose of this appraisal is to assist the intended user, Attorney Michael Sheehan and other involved in the loan decision process at Liberty Utilities in establishing a market value of the fee simple estate on which to make future financial decisions.

This appraisal report was prepared for the exclusive use of Liberty Utilities. This report is not intended for any other use. Any use of this appraisal by any other person or entity, or any reliance or decisions based on this appraisal, are the sole risk of the third party. Crafts Appraisal Associates, Ltd. accepts no responsibility for damages suffered by any third party as a result of reliance on, decisions made, or actions taken based on this report.

The appraisal research and analysis are summarized in the following report. As such, it might not include full discussions of the data, reasoning, and analyses that were used in the appraisal process to develop the opinion of value. Supporting documentation concerning the data, reasoning, and analyses is retained in our files. The information contained in this report is specific to the needs of the client and for the intended use stated in this report.

I hereby certify that I have inspected the subject property, that I have considered all factors that were pertinent to the value estimate, and that I have not knowingly or intentionally omitted any important data. I further certify that I have no present or contemplated future interest in the property, and that my professional fee is not dependent upon the value estimate.

On the basis of my inspection, investigation, study and analysis, I am of the opinion that the subject's value is:

MARKET VALUE OF THE FEE SIMPLE ESTATE AS OF JULY 13, 2017...... $925,000

Respectfully submitted,

Donald E. Watson

Donald E. Watson
Certified General Appraiser
No. NHCG-191

TABLE OF CONTENTS

Summary of Important Facts and Conclusions 1

RECITALS

Scope of Work 4
Municipal Considerations 8
Subject Property Description 16

VALUATION

Sales Comparison Approach 20

ADDENDUM

Certification 32
Statement of Limiting Conditions 34
Appraiser's Qualifications 35
Partial List of Clients Served 36

SUMMARY OF IMPORTANT FACTS & CONCLUSIONS

Owner of Record:	Rock Acquisition, LLC
Location:	Tuscan Village Development 71 Rockingham Park Boulevard Salem, New Hampshire
Map/Lot:	98/7887
Deed Reference:	Book 5763, Page 52, Rockingham County Registry of Deeds.
Land Area:	A hypothetical 1.23± acre parcel within the larger 120.64± acre parcel that comprises the former Rockingham Park slated to be developed in a mixed-use fashion known as Tuscan Village.
Improvements:	Vacant land
Zoning:	Commercial Industrial (CIC)
Flood Zone:	According to the National Flood Insurance Program Map for Rockingham County, Community Panel No. 33015C0563E, with an effective date of May 17, 2005, the subject appears to be in an area designated as Zone X, an area outside of any known flood zone. There are some flood zone areas associated with the larger parcel and the exact placement of the subject within that is not quite defined. However, based on exhibits provided it appears it is not in the flood zone.
Assessment:	There is no meaningful assessment for the subject as appraised here.
Highest & Best Use:	Commercial development
Intended Use/User:	The purpose of this appraisal is to assist the intended user, Attorney Michael Sheehan, Senior Council, and others

involved in decisions at Liberty Utilities to establish the market value to assist in making future financial decisions.

This appraisal report was prepared for the exclusive use of Liberty Utilities. This report is not intended for any other use. Any use of this appraisal by any other person or entity, or any reliance or decisions based on this appraisal, are the sole risk of the third party. Crafts Appraisal Associates, Ltd. accepts no responsibility for damages suffered by any third party as a result of reliance on, decisions made, or actions taken based on this report.

Extraordinary Assumptions: No hazardous materials or conditions were observed during the property inspection, nor were any disclosed. This report has not been prepared in an environmental-risk capacity and should not be construed as such. This report assumes that the subject property is free and clear of hazardous materials. If this is found to be untrue, the value in this appraisal could be affected.

This appraisal is based upon the assumption that a 1.23± acre parcel as represented by the client will be subdivided from the larger parcel for use as a utility substation. This is to service the proposed developed which is assumed to be completed.

The above are considered to be an *Extraordinary Assumptions*. USPAP 2014-2015 Edition, defines extraordinary assumption as: *"an assumption directly related to a specific assignment as of the effective date of the assignment results, which, if found to be false, could alter the appraiser's opinions or conclusions."*

Hypothetical Condition: This appraisal values a 1.23± acre parcel that has yet to exist but is assumed to have been subdivided from the larger parcel for the sake of this appraisal.

USPAP 2014-2015 Edition, defines *Hypothetical Condition* as: *"a condition directly related to a specific assignment, which is* *contrary to what is known by the appraiser to exist on the effective date of the assignment result, but is used for the purpose of analysis."*

Estimated Exposure Time:	6-12 months
Valuations:	Sales Comparison Approach $925,000
Valuation Date:	July 13, 2017
Report Date:	July 27, 2017
Appraiser:	Donald E. Watson Certified General Appraiser No. NHCG-203

SCOPE OF WORK

INTRODUCTION

The purpose of this assignment is to estimate the Market Value of the fee simple estate of 1.23± acres proposed to be subdivided from a larger parcel to be developed and known as Tuscan Village in Salem, New Hampshire as of July 13, 2017. Inspected on July 13, 2017, the subject of this report consists of a hypothetical 1.23± acres that will be dedicated to Liberty Utilities' installation of a substation to service the larger Tuscan Village Development on the former Rockingham Park. Exhibits provided by Liberty Utilities indicate this parcel to be on the eastern portion of the larger site near North Broadway. It shows it being on the perimeter of a parking area that will service a commercial portion of the development that is yet to be developed.

The appraisal research and analysis are summarized in the following report. As such, it might not include full discussions of the data, reasoning, and analyses that were used in the appraisal process to develop the opinion of value. Supporting documentation concerning the data, reasoning, and analyses is retained in our files. The information contained in this report is specific to the needs of the client and for the intended use stated in this report.

In preparing this appraisal my work included the following:

- Personal inspection of the subject on July 13, 2017;
- Review of available information from the Town of Salem's assessor's office;
- Review of various exhibits provided by the client;
- Inspection of the subject neighborhood to establish uses and trends within the neighborhood;
- Discussions with real estate professionals including other appraisers, brokers, and property owners to compile a pool of data to assist in the valuation section of this report;
- Research of databases including Crafts Appraisal, Paragon, and the Warren Group.

More information on the Scope of Work, such as the type and extent of the data researched and analysis applied, is discussed in the valuation section(s) of the report.

DEFINITION OF MARKET VALUE

Market Value is the major focus of most real property appraisal assignments. Both economic and legal definitions of Market Value have been developed and refined. A current economic definition agreed upon by federal financial institutions in the United States of America is:

The most probable price which a property should bring in a competitive and open market under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus. Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby:

1. *buyer and seller are typically motivated;*
2. *both parties are well informed or well advised, and acting in what they consider their own best interests;*
3. *a reasonable time is allowed for exposure in the open market;*
4. *payment is made in terms of cash in United States dollars or in terms of financial arrangements comparable thereto; and*
5. *the price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.*

This definition is from regulations published by federal regulatory agencies pursuant to Title XI of the Financial Institutions Reform, Recovery, and Enforcement Act (FIRREA) of 1989 between July 5, 1990, and August 24, 1990 by the Federal Reserve System (FRS), National Credit Union Administration (NCUA), Federal Deposit Insurance Corporation (FDIC), the Office of Thrift Supervision (OTS), and the Office of Comptroller of the Currency (OCC). This definition is also referenced in regulations jointly published by the OCC, OTS, FRS, and FDIC on June 7, 1994, and in the *Interagency Appraisal and Evaluation Guidelines*, dated December 10, 2010, Federal Register/Volume 75 No. 237, Page 77471.

PROPERTY RIGHTS APPRAISED

This report is concerned with the value of the subject's fee simple estate. The Dictionary of Real Estate Appraisal, Fifth Edition, defines fee simple estate as: *"The absolute ownership unencumbered by any other interest or estate, subject only to the limitations imposed by the governmental powers of taxation, eminent domain, police power, and escheat."*

EXTRAORDINARY ASSUMPTIONS

No hazardous materials or conditions were observed during the property inspection, nor were any disclosed. This report has not been prepared in an environmental-risk capacity and should not be construed as such. This report assumes that the subject property is free and clear of hazardous materials. If this is found to be untrue, the value in this appraisal could be affected.

This appraisal is based upon the assumption that a 1.23± acre parcel as represented by the client will be subdivided from the larger parcel for use as a utility substation. This is to service the proposed developed which is assumed to be completed.

HYPOTHETICAL CONDITION

This appraisal values a 1.23± acre parcel that has yet to exist but is assumed to have been subdivided from the larger parcel for the sake of this appraisal.

VALUATION METHODOLOGIES

In appraising real estate the following methods may be used:

- The Cost Approach, which adds the estimated value of the underlying land and the depreciated improvement cost to derive a value indication.
- The Sales Comparison Approach, which compares the subject to sales of similar properties to derive a value indication.
- The Income Approach, which has two potential methodologies; Direct Capitalization and Discounted Cash Flow Analysis. The first methodology uses capitalization techniques to convert anticipated benefits into an indication of value, while the second applies a discount rate to a set of projected income streams and a reversion to determine value.
- The Development Procedure, which values undeveloped acreage by discounting the cost of development and the probable proceeds from the sale of developed sites. This method incorporates components from each of the other three approaches.

In appraising the subject, I used the Sales Comparison Approach, which is explained in the valuation section of this report. I did not utilize the Cost or Income Approaches given in this market they are utilized to value improved properties and since the subject, as described here, is vacant land they would not result in an appropriate value. For this reason the Cost and Income Approaches were not developed. The Development Procedure can sometimes be utilized in valuing vacant land but to do so requires engineering, approvals, etc. Since the subject does have these the Development Procedure would not be appropriate and was also not developed. The Sales Comparison Approach will result in a credible opinion of value for the subject property.

MUNICIPAL CONSIDERATIONS

INTRODUCTION

This section will address specific issues that impact the subject such as community and neighborhood considerations and trends.

MUNICIPAL DESCRIPTION

The subject is in Salem, which is in Rockingham County in the southern part of the state midway between Boston, MA and Concord, NH. The major highways servicing the local area are north/south state Route 28 and east/west Routes 97 and 111. Major links to the regions are provided by Interstates 93 and 495, running north/south and east/west, respectively. Salem is easily accessible via I-93, and is 30 miles north of Boston, 6 miles north of Lawrence, MA, 12 miles east of Nashua, NH and 19 miles southeast of Manchester, the state's largest city.

The population change for Salem totaled 19,643 over 55 years, the sixth largest numeric change was from 9,210 in 1960 to 28,853 in 2015. The largest decennial percent change was an increase of 119% between 1960 and 1970. The next largest percent increase, of 20%, occurred between 1970 and 1980. The 2015 Census estimate for Salem was 28,853 residents, which ranked 7th among New Hampshire's incorporated cities and towns.

The following chart demonstrates the community's growth over the past five decades as compared with that of Rockingham County.

YEAR	SALEM	ROCKINGHAM COUNTY
2015	28,853	299,006
2010	28,776	295,223
2000	28,219	278,748
1990	25,841	246,744
1980	24,124	190,345
1970	20,142	138,951

As of 2015 there are a total of 11,733 housing units in the community. Of that total 8,496 are single-family with 687 two to four units, 1,765 five or more units, and 523 mobile homes or other housing units.

The 2015 Census indicates that Salem's per capita income is $37,325 with a median household income of $79,755.

Salem's major employers are summarized below:

Northeast Rehabilitation Hospital	300
J.C.Penney Co.	200
Reliable Security Guard	135
Salem Haven	120
Home Depot	100

Salem's most distinguishing characteristic is its proximity both to the major highway system and the state of Massachusetts. Much of Salem's economy is affected both positively and negatively, by its location. The most recently published unemployment rates are as follows:

AREA	5/17	5/16
New Hampshire	2.7%	2.7%
Rockingham County	2.9%	2.9%
Salem-Town NH Portion Lawrence, Mass.-NH NECTA	3.6%	3.4%
Salem	3.6%	3.4%

Salem falls within the Lawrence, Massachusetts PMSA and has a higher unemployment rate compared with the remainder of the state of New Hampshire due to the Massachusetts influence. As such, this figure is a weak indicator of the true conditions in Salem, New Hampshire.

The retail sector has always been a bright spot for Salem. The lack of sales tax in New Hampshire, along with the easy access from Massachusetts, are a driving force of this retail activity. There are many retail businesses along North and South Broadway, aka Route 28, which have benefited from their proximity to Massachusetts. Over 300 retail businesses offer a wide variety of consumer merchandise.

Salem is governed by a five-member board with members elected for three-year terms and a full-time town manager. The selectmen and town warrants are voted on in the annual town meeting in March of each year. The community's planning and zoning functions are handled by a planning department, and are administered by a full-time director and a five-person planning board, who implement the town's land use and zoning ordinances.

In summary, Salem has traditionally benefited from its location along the New Hampshire/Massachusetts border and its proximity to Route 93. Salem's population has grown over the last ten years, but at a rate slower than many of the surrounding communities. From an employment standpoint, almost a full 50% of the town's labor force works in Massachusetts, which currently contributes to a higher unemployment rate in the town, than in the state overall.

Historically, Salem has had a strong economic base, especially in the retail and industrial sectors. Again, this trend is partly due to the favorable tax structure in New Hampshire and the exceptional access via Interstate 93. The Mall at Rockingham Park, due to its size and location attracts new businesses, employees and shoppers.

The factors that have contributed to Salem's strength in the past are still present. Although the overall economies of both New Hampshire and Massachusetts have impacted the town, its non-manufacturing segment, including retailing, has remained strong.

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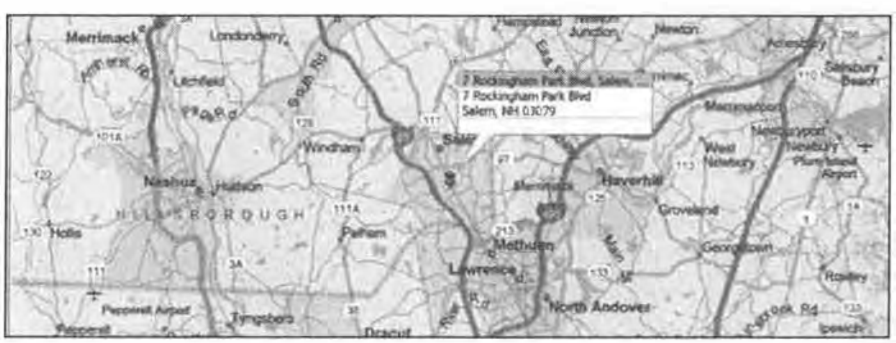


MARKET ANALYSIS

NEW HAMPSHIRE HEADING INTO 2017 WITH STRONG ECONOMY

New Hampshire is closing out 2016 with the nation's lowest unemployment rate, wages that are on the rise and strong real estate sales.

Combined, these factors show the state's economy is strong heading into 2017. The state's gross domestic product growth rate of 2.9 percent is among the highest in the nation, according to the most recently available federal data.

"Right now the state is in very good shape, probably the best shape it's been in economically in 10 years," said Russ Thibeault, president of Applied Economic Research in Laconia.

Still, there are challenges. Businesses say the low unemployment rate is making it hard to find skilled workers for open jobs. The state's modest in-migration also may make it hard for the state to sustain its growth.

"Without more people, the economy just can't grow anymore," said Steve Norton, executive director of the New Hampshire Center for Public Policy Studies.

UNEMPLOYMENT

New Hampshire's unemployment rate sat at 2.7 percent in November, tying with South Dakota for the lowest in the nation. That compares to 4.6 percent unemployment nationally.

A low unemployment rate increases competition for workers, which can in tum raise wages, Thibeult said. It also makes it easier for people seeking jobs to find one, because there is less competition.

On the flip side, New Hampshire businesses say it's hard to find skilled workers, particularly in fields such as advanced manufacturing. The state doesn't keep data on job vacancies, so it's hard to know how many positions are unfilled. But a lack of available workers could stop businesses from expanding.

"Almost anywhere you tum in the economy they are dealing with a shortage of skilled workers," said David Juvet, senior vice president of the Business and Industry Association.

HOUSING

New Hampshire's housing market is seeing an uptick in sales and home prices, according to recent data from the New Hampshire Association of Realtors.

November data show closed sales on single family homes went up 18.4 percent over the past year. The median sale prices for single family homes went up 5.9 percent, to $248,750, in the same period. Inventory of available homes has fallen quickly, making it more of a sellers' than a buyers' market.

Mortgage interest rates remain low but have finally started to rise, which adds uncertainty to the housing market heading into 2017, Thibeault said.

JOBS AND WAGES

Wages in New Hampshire also are climbing, offering another indicator of economic strength. On average, they're up 4 to 5 percent, according to data from the federal Bureau of Labor Statistics.

The median wage in New Hampshire is roughly $24 an hour, but that can vary sharply based on where someone lives. In the Lebanon-Hanover area, for example, the median wage hits almost $28 an hour. But over in Conway and Wolfeboro, an area dominated more by tourism and retail jobs, the median wage is closer to $19, according to a November report by the New Hampshire Department of Employment Security.

Roughly 734,000 workers were employed in New Hampshire as of November.

Leisure and hospitality jobs increased by 6 percent since last year, the highest increase, according to federal data.

Source: Kathleen Ronayne *Associated Press*

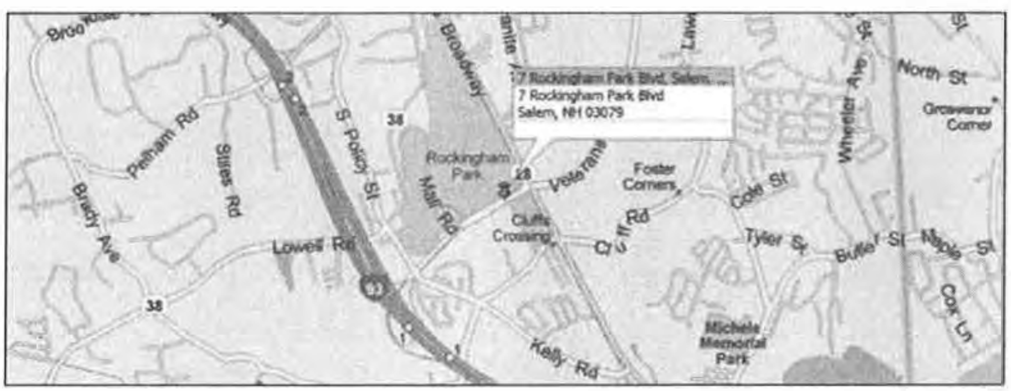
NEIGHBORHOOD DESCRIPTION

The subject is located on the west side of Route 28, South Broadway. It is sandwiched between Route 28 and Interstate 93. The neighborhood boundaries are roughly defined as Route 28, South Broadway, to the east, Route 97, Main Street, to the north, Interstate 93 to the west, and Rockingham Boulevard to the south.

The subject neighborhood has excellent access to the major highway system of the region by virtue of its proximity to Interstate 93. I-93 is the major north/south travel corridor running through central New Hampshire. Southerly it leads into Massachusetts and the greater Boston area. To the north it heads into the Manchester/Bedford market area and on into the White Mountains and Lake Regions of the state. The neighborhood has immediate access at either Exit 1, which is from Rockingham Park Boulevard or Exit 2 from Route 97, Main Street. Route 28 is a heavily traveled and commercially developed secondary state highway bisecting the community in a north/south direction. Prior to the construction of I-93, it fulfilled a similar role accessing the central portion of the state. It continues to be heavily traveled due to the retail development along the street.

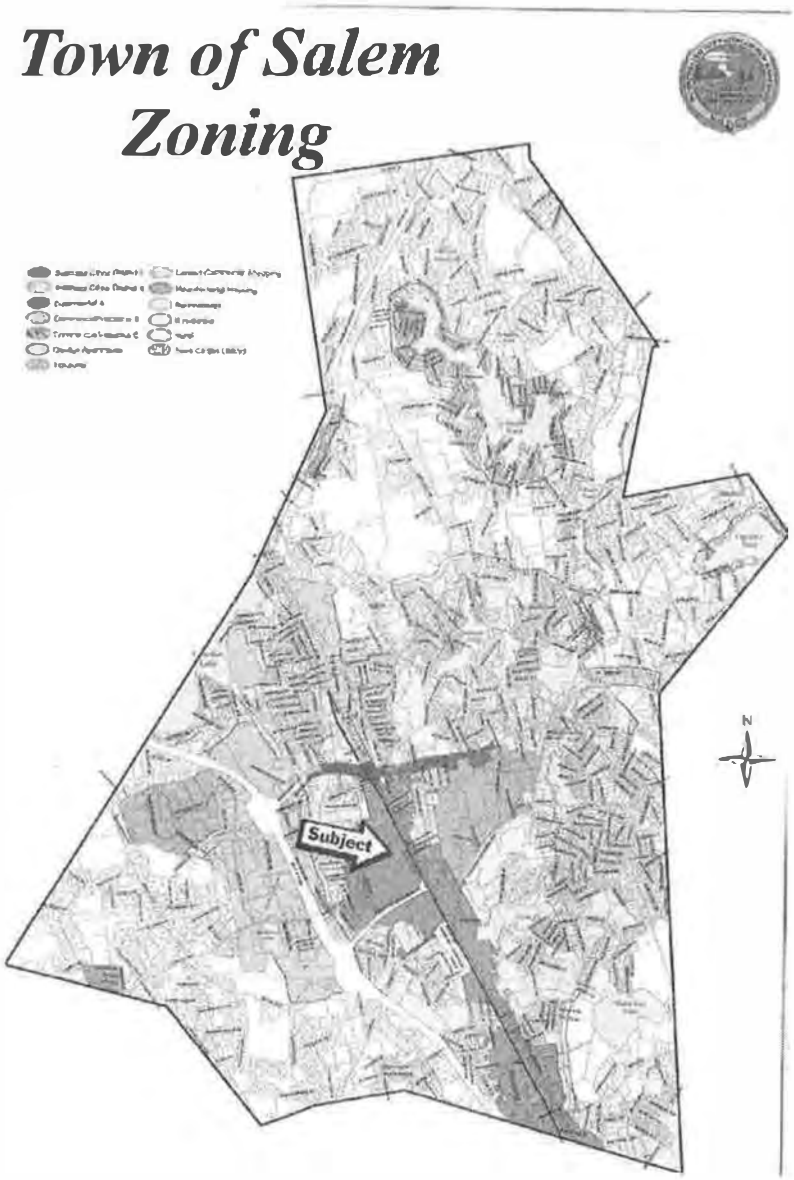
Route 28 is known as South Broadway from the intersection of Route 97, Main Street, to the north, southerly to the Massachusetts border. Due to the fact that Massachusetts has a sales tax, while New Hampshire does not, the locations in close proximity to the border have been heavily developed with commercial properties, more specifically retail. As a result South Broadway is one of the premier locations in the southern part of New Hampshire. Virtually all national retail franchises, including fast food restaurants, are located on this street. These are situated in freestanding buildings as well as anchored plazas. There are a number of automobile related uses on the street including dealerships.

In the subject's immediate area, in addition to the subject itself, the dominant feature is the Mall of Rockingham Park. This is a 1,000,000± SF Mall constructed during the early 90's. The streets in the western section of the subject's immediate neighborhood are primarily older retail.



ZONING

The subject is located in the Commercial A (CA) Zone. This zone permits a wide range of commercial uses with minimal dimensional requirements.



ASSESSMENT

The subject is a hypothetical 1.23± acre lot proposed to be subdivided from the larger 120± acre parcel and as such does not have an assessment as of the date of this appraisal.

SUBJECT PROPERTY DESCRIPTION

INTRODUCTION

This property description is more based on plans provided by the client on site inspection the specific property was difficult to locate within the larger parcel.

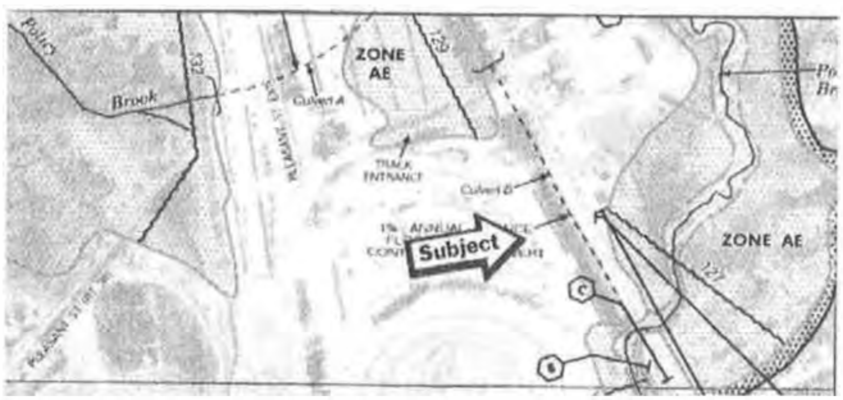
The following property description is presented for appraisal purposes only and is not intended to be exhaustive in nature.

SITE DESCRIPTION

The subject is an irregularly shaped parcel consisting of 1.23± acres. It is proposed to be located in the eastern portion of the larger parcel adjacent to what is proposed for a retail development closest to the area that is proposed for a cinema. The site has some topographic issues but it would more than likely be improved to generally level as part of the site preparation of the larger development. Its frontage and access would come from a to-be-built private road servicing the aforementioned retail development.

UTILITIES: The area is serviced by municipal water, sewer, electric, telephone, and natural gas.

FLOOD ZONE: According to the National Flood Insurance Program Map for Rockingham County, Community Panel No. 33015C0563E, with an effective date of May 17, 2005, the subject appears to be in an area designated as Zone X, an area outside of any known flood zone. There are some flood zone areas associated with the larger parcel and the exact placement of the subject within that is not quite defined. However, based on exhibits provided it appears it is not in the flood zone.



EASEMENTS: The appraiser is not aware of any easements or adverse conditions that would negatively impact the subject property.

HISTORY OF CONVEYANCE

According to the Rockingham County Registry of Deeds, there has not been a transfer of the subject as described here. The larger parcel transferred as follows:

SALE DATE	10/14/2016
SALE PRICE	$40,000,000
BOOK/PAGE	5763/52
GRANTOR	Rockingham Venture
GRANTEE	Rock Acquisition, LLC
COMMENTS	This was the sale of a larger parcel of what was known as Rockingham Racetrack. The purchaser in this transaction is proposing to develop it in a life style type center with a variety of uses including retail, hospitality, residential. The subject parcel which would be subdivided from this larger parcel would be to provide area for a utility substation by Liberty Utilities because of the increased demand to service the proposed development.

EXPOSURE TIME

Reasonable exposure time is one of a series of conditions in most market-value definitions. Exposure time is always presumed to proceed the effective date of the appraisal. USPAP, 2014-2015 Edition, defines exposure time as follows:

> *"The estimate length of time the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal;"*

The subject represents a small parcel of what is a larger development. Given the exhibits provided to me it would make for a nice outparcel to the larger retail development which it abuts. As that development comes to fruition there would be good demand for this parcel. Therefore, I feel that the exposure would be dictated by the pace of development of the larger development. As that development moves forward I feel that the exposure would be a relatively short period of time however, as of the date of this appraisal there would be little demand for the parcel as it sits today. Therefore in summary, the exposure time associated with the subject is directly related to the development timeline of the larger development.

HIGHEST AND BEST USE

The Dictionary of Real Estate Appraisal, Fourth Edition, defines Highest and Best Use as:

"The reasonably probable and legal use of vacant land or an improved property, which is physically possible, appropriately supported, financially feasible, and that results in the highest value. The four criteria the highest and best use must meet are legal permissibility, physical possibility, financial feasibility, and maximum productivity."

The subject is a hypothetical 1.23± acre parcel that is irregular in shape and is located on the eastern side of the larger 120± acre parcel. It is directly adjacent to what is proposed to be a larger retail development. Its access would come from a road that would be developed along with that development.

The development which is to be known as Tuscan Village is a lifestyle center which will have a variety of uses including the adjacent retail development but will also have other components such as hospitality and residential. It is the site of the former Rockingham Racetrack. The area around the larger parcel is heavily developed in a commercial fashion. Directly adjacent to the larger parcel is the large Mall at Rockingham Park. The larger parcel is surrounded by heavily developed roads known as Rockingham Park Boulevard, South Broadway Street, and Main Street. Access is very good and my feeling is that the subject parcel would represent a good outparcel to be developed in concert with the larger retail parcel. Given its size it would most likely support a restaurant use although a small standalone retail use would also be appropriate.

SALES COMPARISON APPROACH

Introduction

The Sales Comparison Approach compares the subject to similar properties that have sold in the same market or in similar markets to derive an indication of its market value.

Research

I surveyed the subject's market area for information regarding sales and listings of properties similar to the subject. Research was conducted around the Southern and Seacoast part of the State for well located commercial parcels. Particular attention was paid to those in close proximity to larger commercial developments such as that of the subject. That research resulted in a relatively large pool of comparable sales from which the four that were considered to be the most comparable to the subject were chosen for analysis here. They consist of one each in the communities of Dover, Manchester, Hooksett, and Salem.

I gathered information regarding comparable properties from the Real Data Research Service, INNOVIA - the Northern New England Network MLS, CIBOR NH – the Commercial MLS, Crafts Appraisal Database, local and county municipal offices, brokers and appraisers. All of these sources are believed to be reliable. Parties familiar with the transactions confirmed the transactions whenever possible.

Unit of Comparison

In reviewing the comparable sales, it was necessary to determine a meaningful unit of comparison. A definite relationship was found to exist among the comparable sales in the form of sale price per acre. As such, I have determined that the sale price per acre is the most meaningful unit of comparison in analyzing the subject and the comparables.

Summary of Comparable Properties

The comparables used in this approach are discussed briefly below. Please refer to the Comparable Sale Forms that follow this section for more information regarding these properties.

COMP 1: This represents the March 2017 sale of a four parcel property located at 817, 819, and 825 Central Ave and 3 Ridge Street in Dover, New Hampshire. The total size of the property was 1.14± acres and it sold for $950,000 or $673,759/acre. The parcel had 347.92±' of frontage on Central Ave and an additional 170±' of frontage on Ridge Street. The parcels were improved with a number of older residential or multi unit residential all of which were in below average condition and were felt to not add any contributory value to the sale. The buyer purchasing the property planned to develop it with a 15,000± SF owner-occupied retail center. This property is a corner parcel located in direct proximity to the Hannaford and Shaw's development and is considered to be a good to very good commercial location.

COMP 2: This represents the October 2014 sale of property located at 5 Driving Park Drive in Manchester, New Hampshire. This 2.58± acre parcel sold for $1,700,000 or $656,878/acre. The property was purchased by the owner of a furniture store who subsequently improved it with a 64,000± SF two story building. The property is located one parcel removed from South Willow Street at a signalized intersection. It has some visibility from South Willow Street and is adjacent to a large commercial development from which it has access through a number of the parking lots just east of South Willow Street as the City has prevailed on owners to make this available from one parcel to another to relieve some of the shopping traffic along South Willow Street.

COMP 3: This represents the April 2016 sale of property located at 1293 Hooksett Road, Hooksett, New Hampshire. This 1.05± acre parcel sold for $795,000 or $757,143/acre. The property is located at a signalized intersection in close proximity to a dense retail development. It represents a corner parcel with access from two roads and has subsequently been improved with a branch bank.

COMP 4: This represents the December 2015 sale of property located at 417 South Broadway in Salem, New Hampshire. This 4.898± acre parcel sold for $3,900,000. However, there was an existing building on the site which was going to be reused by the purchaser who is an abutting property owner, owning a car dealership across South Broadway from the subject. They intended to use it as a used car dealership. The depreciated contributory value of the building and the site improvements was $700,000 making the effective price for the land $3,200,000 or $653,328/acre. Some of the total acreage was felt to be impacted by wetlands and would not support building however it may have been able to contribute to the density on the parcel.

SALE CONSIDERATIONS

In real estate transactions, property rights transferred, terms of sale (financing), conditions of sale (buyer/seller motivation), and expenses incurred immediately after purchase are factors that can influence sale price. In this analysis Comps 1, 2, and 3 involved fee simple estate, had conventional financing or were cash transactions, and appear to have been typically motivated, arm's length transactions. Since the Market Value of the subject's fee simple estate is being appraised here, and the other sale considerations are typical, adjustments have not been applied for these factors.

Comp 4 was sold to what would be considered an abutting property owner given that they had a car dealership directly across the street. They were going to use this parcel for expansion of the used car operation of that dealership. As such, I have adjusted it down by 10%.

MARKET CONDITIONS

Market conditions may change over time due to inflation, deflation, fluctuations in supply and demand, or other factors. As a result, the comparable sales may require adjustments to reflect changes in market conditions between the sale dates and the date of this report. In a market in which prices are increasing, these adjustments take the form of positive appreciation adjustments.

In considering changes in market conditions since the comparables sold, I consulted business publications for an overview of general economic conditions, industry-specific publications including the New England Real Estate Journal, The Appraisal Journal, and local brokers and appraisers familiar with the subject's market area.

The market for well located commercial properties has improved commensurate with the improvement in the overall commercial marketplace. While the broader recovery has been led by industrial and multi-family residential, commercial properties, as noted, have begun to improve. After an initial period of stabilization where vacancies and credit losses began to decrease the market is now to the point where landlords can write multi-year leases some with escalations. As the financial performance of these properties has improved investors have become more interested in the property type and therefore improved commercial properties have shown appreciation.

It is felt that the demand for improved properties has improved the demand for well located commercial land and has also led to some appreciation in that market. As such, I have adjusted each of the comparables upward by 0.25% per month from January 2015 to the date of appraisal.

Other Potential Adjustments

Relevant differences that may influence sale price can include size, location, and a variety of physical characteristics. In the case of the subject and the comparables it is felt that there are two areas that require formal adjustment. Those are location and physical features and are made as follows:

Location: This appraisal assumes that the subject will be adjacent to a larger retail establishment and will benefit from the synergy of the overall development. As such, it is felt that it will be a very good commercial location within that commercial development however, it will not benefit necessarily from the broader traffic flow as if it was located along a main artery.

Comp 1 is located on Central Ave, which is Dover's primary commercial thoroughfare. It is an area that is heavily developed with commercial development. This parcel is located in direct proximity to two large grocery store anchored centers and is a corner location. As such, I feel this is a superior location and have adjusted it downward by 10%.

Comp 4, which is located directly on South Broadway in Salem, was felt to be in the same market as the subject, does benefit from a closer proximity to the Massachusetts boarder which drives much of the retail development in Salem and also is a heavily developed area. Therefore, I feel this comparable is superior from a locational standpoint of view and have adjusted it downward by 10%.

Comps 2 and 3 were felt to be similar. Comp 2 is located in Manchester and is one parcel removed from South Willow Street although it has access at a signalized intersection. It is in close proximity to other retail development at the northern end of South Willow Street where development has begun to decline. Given its greater proximity to South Willow Street, some of which is offset by its location on South Willow Street, I feel that it is similar to the subject even though it does have some benefits from a visibility standpoint of view. Comp 3 was also felt to be similar. It was at a signalized intersection in proximity to some large development. The subject property upon completion will have a greater density in supportive type uses however I feel that is offset by the signalized intersection and therefore no adjustment has been made to this comparable.

PHYSICAL FEATURES: The subject property will be a flat site serviced by all municipal utilities upon completion of the larger development. Comps 1, 2, and 3 were all felt to be similar in that they were ready to develop sites and as such no adjustment has been made to those.

Comp 4, as noted, has a certain amount of wetlands on the larger parcel. The impact of those wetlands is such that perhaps they would not support building however it does have contributory value as far as density and parking. Therefore, I feel that it is inferior and have adjusted it upward by 20%.

VALUE CONCLUSION

The comparable properties and their adjustments are summarized in the table that follows this section. The analysis indicates the following adjusted per acre values:

Comp 1..........................	$612,446
Comp 2..........................	$707,786
Comp 3..........................	$785,536
Comp 4..........................	$677,517

The adjusted per acre values range from $612,446 to $785,536. Each of the sales provides a meaningful indication of value for the subject after adjustments. Of the four comparables Comp 4 was accorded the least weight. While it is the only comparable in Salem it was bought by an abutter and was also impacted by wetlands. While both of these things were adjusted for I feel for those reasons it is a slightly less reliable comparable and have accorded it the least weight.

The other three comparables were felt to be better indicators of value. Comp 2 which is the oldest comparable is similar in the fact that it is a parcel that derives much of its value because of its proximity to other commercial development and is not located directly on the main artery. For that reason I feel that it should be given consideration.

Based on this investigation and analysis, as well as personal experience and judgment, I have formed the opinion that the subject warrants a value estimate of $750,000 per acre, as shown:

$750,000/acre x 1.23± acres = $922,500
ROUNDED TO $925,000

- - - - - - - - - - -

COMPARATIVE VALUE ANALYSIS CHART

FACTORS	SUBJECT	COMP 1	COMP 2	COMP 3	COMP 4
Location	71 Rockingham Park Boulevard Salem, NH	825 Central Ave Dover, NH	5 Driving Park Dr. Manchester, NH	1293 Hooksett Rd. Hooksett, NH	417 South Broadway Salem, NH
CAA Ref. No.	N/A	7991	7801	7892	7844
Sale price	N/A	$950,000	$1,700,000	$795,000	$3,200,000[1]
Sale date	N/A	3/17	10/14	4/16	12/15
Rights transferred	N/A	Fee simple	Fee simple	Fee simple	Fee simple
Financing	N/A	Cash to Seller	Conventional	Cash	Conventional
Motivation	N/A	Arm's length	Arm's length	Arm's length	Abutter -10%
Expenses immediately after purchase	–	–	–	–	–
Market Conditions	N/A	+1%	+7.75%	+3.75%	+4.75%
Adjusted price	N/A	$959,500	$1,831,750	$824,813	$3,016,800
No. of Acres	1.23± acre	1.41± acres	2.588±	1.05±	4.898±
Adjusted Price per Acre	N/A	$680,496	$707,786	$785,536	$615,925
Location	N/A	Superior -10%	Similar	Similar	Superior -10%
Physical Features	N/A	Similar	Similar	Similar	Inferior +20%
INDICATED VALUE/ACRE	**N/A**	**$612,446**	**$707,786**	**$785,536**	**$677,517**

[1]Effective Price

COMPARABLE LAND SALE 1

SALE DATA

Location:	817, 819, & 825 Central Ave and 3 Ridge Street, Dover, NH
Grantor:	Dean A. Fournier Charitable Trust 2005
Grantee:	Jeanette Gestapo, LLC
Sale Date:	3/1/2017
Sale Price:	$950,000
Sale Price Per Acre:	$673,759
Date Recorded:	3/22/2017
County/Deed Type:	Rockingham/Fiduciary
Book/Page:	4464/111
Rights Transferred:	Fee simple
Conditions of Sale:	Arm's length
Financing:	Cash to Seller
Confirmed By:	DEW
Date:	7/1/2017
Source:	Broker

PHYSICAL DESCRIPTION

Size:	1.41± acres
Frontage:	347.92±' on Central Ave/170±' on Ridge St.
Shape/Road Grade:	Slightly irregular/At grade
Topography:	Level

MUNICIPAL DATA

Water/Sewer/Gas:	Municipal/Municipal/Natural
Zoning:	Business - 3
Improvements/Land Use:	Older residential structures to be razed
Highest & Best Use:	Commecial development

REMARKS

These are four adjacent parcels of land that were purchased together for $950,000. The parcels were each improved with an older wood-frame residence or multi-unit residences that were in average to below average overall condition at the time of sale. They had no contributory value to the sale. The buyer purchased the property planning to develop it with a 15,000± SF owner-occupied retail building. This is located at a corner and less than one-quarter mile east of the Hannaford and Shaw's development.

7991

COMPARABLE LAND SALE 2

SALE DATA

Location:	5 Driving Park Drive, Manchester, NH
Grantor:	Five Driving Park, LLC
Grantee:	Leclerc Plaza, LLC
Sale Date:	10/1/2014
Sale Price:	$1,700,000
Sale Price Per Acre:	$656,878
Date Recorded:	10/30/2014
County/Deed Type:	Hillsborough/Warranty
Book/Page:	8704/509
Rights Transferred:	Fee simple
Conditions of Sale:	Arm's length
Financing:	Conventional
Confirmed By:	DEW
Date:	10/1/2014
Source:	Grantee & Documentation

PHYSICAL DESCRIPTION

Size:	2.588± acres
Frontage:	On Driving Park Drive
Shape/Road Grade:	Irregular/Generally at grade
Topography:	Level

MUNICIPAL DATA

Water/Sewer/Gas:	Municipal/Municipal/Natural
Zoning:	General Business (B-1)
Improvements/Land Use:	9,600± SF building to be razed
Highest & Best Use:	Commercial development

REMARKS

This property subsequent to the sale was improved with a 64,000± SF two story furniture sales building. In addition to its access from Driving Park Drive, which places it one parcel removed from South Willow Street, there is generally a pass through among these properties located on the west side of South Willow Street that allows free passage without having to access South Willow Street directly. This property is located below the grade of South Willow Street and behind a Wendy's restaurant, but does have some visibility from South Willow Street. The purchaser built a furniture store which is his third furniture store in the southern New Hampshire area.
7801

COMPARABLE LAND SALE 3

SALE DATA

Location:	1293 Hooksett Road, Hooksett, NH
Grantor:	John M. Kelly Revocable Trust of 1993
Grantee:	Merrimack County Savings Bank
Sale Date:	4/1/2016
Sale Price:	$795,000
Sale Price Per Acre:	$757,143
Date Recorded:	4/1/2016
County/Deed Type:	Merrimack/Warranty
Book/Page:	3510/1370
Rights Transferred:	Fee simple
Conditions of Sale:	Arm's length
Financing:	Cash
Confirmed By:	DEW
Date:	8/1/2016
Source:	Grantee/Public Records

PHYSICAL DESCRIPTION

Size:	1.05± acres
Frontage:	Hooksett Road
Shape/Road Grade:	Irregular/Slightly above grade
Topography:	Generally level

MUNICIPAL DATA

Water/Sewer/Gas:	Municipal/Municipal/Natural
Zoning:	Commercial
Improvements/Land Use:	Small auto service building to be razed
Highest & Best Use:	Commercial development

REMARKS

This parcel had a couple of older auto service buildings on it that were owned by a used car entity located across Hooksett Road from these. They never really utilized these properties and subsequently sold it to be developed with a branch bank for Merrimack County Savings Bank.

7892

COMPARABLE LAND SALE 4

SALE DATA

Location:	417 South Broadway, Salem, NH
Grantor:	State of New Hampshire
Grantee:	South Broadway Development, LLC
Sale Date:	12/24/2015
Sale Price:	$3,900,000
Sale Price Per Acre:	$1,387,000
Date Recorded:	12/30/2015
County/Deed Type:	Rockingham/Quitclaim
Book/Page:	5681/1714
Rights Transferred:	Fee simple
Conditions of Sale:	Abutter
Financing:	Conventional
Confirmed By:	AJC
Date:	5/1/2016
Source:	Public Records/Appraisal

PHYSICAL DESCRIPTION

Size:	4.898± ac (2.998± usable)
Frontage:	400±' on South Broadway
Shape/Road Grade:	Irregular/At grade
Topography:	Level

MUNICIPAL DATA

Water/Sewer/Gas:	Municipal/Municipal/Natural
Zoning:	Commercial/Industrial C
Improvements/Land Use:	See remarks
Highest & Best Use:	Commercial

REMARKS

Reportedly the improvement was constructed in 1965 as a state police barracks. Since the date of construction the building has been expanded and upgraded numerous times over the years. More recently it has been utilized as a liquor store. It is situated on a 4.89± acre lot. There are areas of wetlands. The property was purchased by Rockingham Toyota which is located directly across the street. The grantee intends on utilizing the site and the building for the sale of used cars. It is their intent to utilize the existing improvement in some manner. In order to estimate the contributory value of the building I utilized Marshall Valuation Service Section 13. This indicated a depreciated value of the improvements of $630,000. To that I added $70,000 for contributory value of existing site improvements. This would indicate a price paid for the land of $3,200,000.

7844

CERTIFICATION

The Appraiser certifies and agrees that:

1. the statements of fact contained in this report are true and correct.

2. the reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.

3. the Appraiser(s) have no present or prospective interest in the property that is the subject of this report and no personal interest with respect to the parties involved.

4. the Appraiser(s) have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment.

5. the Appraiser(s) engagement in this assignment was not contingent upon developing or reporting predetermined results.

6. the Appraiser(s) compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal.

7. the Appraiser(s) have made a personal inspection of the property that is the subject of this report.

8. no one provided significant real property appraisal assistance to the person(s) signing this certification.

9. the Appraiser(s) have not performed a previous appraisal of the subject property or provided any other service involving the subject property within the three years prior to this assignment.

10. the reported analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the Code of Professional Ethics and Standards of Professional Appraisal Practice of the Appraisal Institute and the Uniform Standards of Professional Appraisal Practice (USPAP).

11. the use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.

12. Crafts Appraisal Associates, Ltd. concentrates its practice in the appraisal of residential, commercial, industrial, special-purpose and development properties throughout New England. As such, the appraisers are competent to undertake this appraisal assignment, and copies of the qualifications of the appraisers who participated in preparing this appraisal are included in the Addendum of this report.

MARKET VALUE OF THE FEE SIMPLE ESTATE AS OF JULY 13, 2017...... $925,000

Donald E. Watson

Donald E. Watson
Certified General Appraiser
No. NHCG-191

STATEMENT OF LIMITING CONDITIONS

1. All facts and data set forth in this report are true and accurate to the best of the appraiser's knowledge and belief.

2. Sketches and maps included in the report are for the purpose of aiding the reader in visualizing the property and are not necessarily drawn to exact scale.

3. No land survey has been made by the appraiser and land dimensions given in the report are taken from available public records and the appraiser assumes no responsibility for the accuracy of such land dimensions.

4. No investigation of legal fee or title to the property has been made. No consideration has been given to liens or encumbrances against the property except as specifically stated in the report.

5. The appraiser assumes that there are no hidden or unapparent conditions of the property, subsoil or structures that would render the property more or less valuable. The appraiser assumes no responsibility for any engineering necessary to uncover such things.

6. Possession of this report, or a copy thereof does not carry with it the rights of publication, nor may it be used for any public purpose without the prior written consent of Crafts Appraisal Associates, Ltd.

7. The Americans with Disabilities Act (ADA) became effective January 26, 1992. The appraiser has not made a specific compliance survey and analysis of this property to determine whether or not it is in conformity with the various detailed requirements of the ADA. It is possible that a compliance survey of the property together with a detailed analysis of the requirements of the ADA could reveal that the property is not in compliance with one or more of the requirements of the act. If so, this fact could have a negative effect upon the value of the property. Since I have no direct evidence relating to this issue, I did not consider possible noncompliance with the requirements of the ADA in estimating the value of the property.

8. The party for whom this report was prepared may distribute copies of this report, in its entirety, to such third parties as may be selected by the party for whom this report was prepared; however, selected portions of this report shall not be given to third parties without prior written consent of the signatories of this report. Further, neither all nor any part of this report shall be disseminated to the general public by the use of advertising media, public relations media, news media, sales media or other media for public communication without the prior written consent of the signatories of this report.

9. This report is based on market conditions existing as of the date of the assignment and the appraiser's estimate of future market conditions. The appraiser is not responsible for unforeseeable events that alter market conditions subsequent to the effective date of the opinion.

10. The use of this report is subject to the requirements of the Appraisal Institute relating to the Code of Professional Ethics and the Uniform Standards of Professional Appraisal Practice.

APPRAISER QUALIFICATIONS
DONALD E. WATSON
CERTIFIED GENERAL APPRAISER NO. NHCG-191

BACKGROUND SUMMARY

With over twenty-nine years in real estate and twenty-two years in the appraisal industry, I have served a wide variety of clients, including municipal and state governments, major universities, lending institutions, nonprofit organizations and investors. I have extensive experience with all property types ranging from unimproved land to subdivisions to improved commercial, industrial and residential properties including complexes and condominiums throughout New Hampshire. My appraisals have been widely used in eminent domain proceedings, estate-planning, financing, divorces, etc.

EDUCATION

NEW HAMPSHIRE COLLEGE, MANCHESTER, NH: Economic & Finance Program

OHIO STATE UNIVERSITY: A.S. Animal Science

HARVARD UNIVERSITY GRADUATE SCHOOL OF DESIGN:
Commercial Real Estate Development & Financing

SOCIETY OF REAL ESTATE APPRAISERS: Course 101, An Introduction to Appraising Real Property

APPRAISAL INSTITUTE:

- Course 1A-1, Real Estate Appraisal Principles
- Course 1A-2, Basic Valuation Procedures
- Course 1B-A, Capitalization Theory & Techniques, Part A
- Course 1B-B, Capitalization Theory & Techniques, Part B
- Course 2-1, Case Studies in Real Estate Valuation
- Course SPP, Standards of Professional Practice, Parts A & B
- Course 530, Advanced Sales Comparison & Cost Approaches
- Report Writing
- Over twenty (20) one and two day seminars

REALTORS' NATIONAL MARKETING INSTITUTE:

- Course CI - 101, Fundamentals of R.E. Investment & Taxation
- Course CI - 102, Fundamentals of Location & Market Analysis
- Course CI- 103, Advanced R.E. Taxation & Marketing Tools for Investment Real Estate

PROFESSIONAL DESIGNATIONS AND AFFILIATIONS

EXPERT WITNESS:	New Hampshire Land and Tax Court Federal Bankruptcy Court Federal District Court New Hampshire Superior Court
CERTIFIED GENERAL APPRAISER:	State of New Hampshire

PARTIAL LIST OF CLIENTS SERVED AND PROPERTIES APPRAISED BY CRAFTS APPRAISAL ASSOCIATES, LTD.

NATIONAL & LOCAL CORPORATIONS

Anagnost Companies
Anheuser Busch Company
Audley Construction Company
Autodesk, Inc.
B&M Railroad
Bentley Pharmaceutical
Brookstone Company
Burger King Corp.
Cabinet Press
Cendant Mobility
Circuit City Stores, Inc.
Cities Services, Inc.
CLD Consulting Engineers
Coca Cola Bottling Company
Coldwell Banker Relocation Corp.
Creative Capital Leasing
Crotched Mountain Properties
Dexter Shoes
Dunkin' Donuts
Eastpoint Properties
ECCO USA, Inc.
Executive Relocation
Freudenberg – North America
GMAC Relocation Services
Gulf Oil Corp.
H&R Block
Henry Hanger Company
Honey Dew Donuts
Howe, Riley & Howe, PC
Hubbard, LLC
Hunneman Real Estate
Infantine Insurance Corp.
Ingersol-Rand Co.
International Automotive Management
J.A. Wright & Company
John B. Sullivan Corp.
John G. Burk & Associates, CPA
JP Chemical Company, Inc.
LaCrosse Footwear, Inc.
Lahey Hitchcock Clinic
Landa & Altsher, PC
Long & Foster Relocation
Mast Road Grain & Lumber
McDonald's Corp.
Midas Muffler
Mobil Oil Corp.
National Gypsum Corp.
New England Circuits, Inc.
Northern Telecom
Old Dutch Mustard Company, Inc.
OSRM Sylvania
Patsy's
Peterbilt Corp.
Pizza Hut
Primacy Relocation
Prudential Relocation
Public Service Company of NH
Rite-Aid
St. Johnsbury Trucking Company, Inc.
Saint-Gobain Performance Plastics
STARS Relocation
State Street Development Corp.
Stewart Title Insurance Co.
Stoneyfield Farm Yogurt, Inc.
Tamposi Company
Texaco
Two Guys Smoke Shop
TransUnion Settlement Solution
Union Leader Corp.
UPS Commercial Underwriters
Velcro USA, Inc.
Verizon
Waterford Development
Weichert Relocation Services
Worldwide Relocation Management, Inc.

SPECIAL PURPOSE PROPERTIES & NONPROFIT ORGANIZATIONS

Abenaqui Country Club
American Red Cross
Assumption Greek Orthodox Church
Boston Minuteman Council
Boys & Girls Club of America
Bretton Woods Resort
Calvary Bible Church
Concord Indoor Tennis & Racquetball Club
Concord Lincoln-Mercury
Consumers Water Company
Dartmouth College
Ear Nose & Throat Physicians & Surgery PA
Easter Seals Society
Executive Health Club
Faith Christian Center
First Church of the Nazarene
Girl Scouts of Swift Water Council
Girl Scouts of Spar and Spindle Council
Good Shepherd School, Inc.
Green Meadow Golf Course, Inc.
Hampshire Hills Racquet & Health Club
Hickory Hill Golf Course, Inc.
Hillsboro Ford
International Brotherhood of Teamsters
Jack O'Lantern Resort

PARTIAL LIST OF CLIENTS SERVED continued

SPECIAL PURPOSE PROPERTIES & NON-PROFIT ORGANIZATIONS – CONTINUED

Manchester Children's Home
Manchester Community Health Center
Manchester Mental Health Center
Mount St. Mary's College
Mountain Club on Loon, The
New Hampshire Children's Aid Society
Portsmouth Regional Hospital
Rockefeller Estate
Serenity Place
Shriner's Hospitals for Children
Sky Meadow Development
Southern NH University
Summit at Four Seasons – Time Share
Talarico Automobile Dealerships
University of New Hampshire (UNH)
Visiting Nurses Association
Wentworth-Douglas Hospital
YMCA Camp Belknap

FEDERAL, STATE & LOCAL MUNICIPALITIES

City of Concord, NH
City of Berlin, NH
City of Dover, NH
City of Franklin, NH
City of Manchester, NH
City of Nashua, NH
Federal Aviation Administration
Greater Nashua Housing & Dev. Corp.
Keene Housing Authority
Laconia Airport Authority
Manchester Airport Authority
Manchester Highway Department
Manchester Housing Authority
Manchester Water Works
NH Housing Finance Authority
NH Dept. of Transportation
Salem Housing Authority
State of New Hampshire
State of Vermont
Town of Bedford, NH
Town of Brattleboro, VT
Town of Candia, NH
Town of Hampton, NH
Town of Hollis, NH
Town of Londonderry, NH
Town of Merrimack, NH
Town of Newmarket, NH
Town of North Andover, MA
Town of Pelham, NH
Town of Salem, NH
Town of Seabrook, NH
Town of Stratham, NH
U.S. Dept. of Transportation
U.S. Environmental Protection Agency
U.S. Postal Service
Veterans' Administration

CONSERVATION ORGANIZATIONS

Bedford Conservation Commission
Bedford Land Trust
Derry Conservation Commission
Derry Preservation Initiative
Dover Conservation Commission
Hollis Conservation Commission
Land Conservation Investment Program
Moose Mountain Regional Greenways
Mount Vernon Conservation Commission
Nature Conservancy
New Hampshire Audubon Society
North Hampton Forever
Society for the Protection of NH Forests
Stratham Conservation Commission
Temple Conservation Commission

LENDING & RELATED INSTITUTIONS

Bank of America
TD BankNorth
Beacon Federal
Berkshire Mortgage Finance
Berlin City Bank
Boston Federal Savings Bank
Cambridge Savings Bank
Centrix Bank & Trust Co.
Chittenden Bank
Citicorp Mortgage, Inc.
Community Bank & Trust Co.
Danversbank
Digital Federal Credit Union
E-Bid Mortgage
EastWest Mortgage
Eastern Bank
Enterprise Bank & Trust Co.
Federal Home Loan Mortgage Corp.
Federal National Mtg. Association
First Colebrook Bank
First Commercial Bank of Chicago
Flagship Bank
Ford Motor Credit Corp
GMAC Mortgage Corp.

PARTIAL LIST OF CLIENTS SERVED continued

Lending & Related Institutions - continued

H&R Block Mortgage Corp.
Haverhill Cooperative Bank
John Hancock Mutual Ins. Company
Laconia Savings Bank
Lake Sunapee Bank
Ledyard National Bank
Marco Community Bank
Mercantile Bank & Trust Co.
Merrimack County Savings Bank
Money Tree Mortgage
New England Federal Credit Union
Ocean National Bank
Passumptic Savings Bank
Salem Five Cents Savings Bank
St. Mary's Bank
Savings Bank of Walpole
Southern NH Bank & Trust Co.
Sovereign Bank
Telephone Credit Union of NH
Toyota Motor Credit Corp.
Traveler's Insurance Co.
Triangle Credit Union
Wachovia Mortgage
Western Federal Credit Union
Winchester Cooperative Bank

LEGAL REPRESENTATIVES

Abramson, Baillinson & O'Leary
Backus, Meyer &Solomon & Rood
Barradale, O'Connell, Newkirk & Dwyer, PA
Beaumont & Campbell, PA
Bernstein, Shur, Sawyer & Nelson, PA
Borofsky, Lewis & Amodeo-Vickery, PA
Bouchard Kleinman & Wright, PA
Boutin & Associates, PLLC
Boynton, Waldron, Doleac, Woodman & Scott, PA
Bradley, Burnett & Kinyon, PA
Bragdon, Berson, Davis & Klein
Cassassa & Ryan Attorneys at Law
Cleveland, Waters & Bass, PA
Cocheco Elder Law Associates
Cronin & Bisson, PC
Curtin Law Office
D'Amante, Couser, Steiner, Pellerin, PA
Devine, Millimet & Branch, PA
DiMento & Sullivan, PA
Duddy Law Offices
Finis E. Williams, III Law Firm
Greene & Perlow, PA
Hall, Morse, Anderson, Miller & Spinelli
Hamblett & Kerrigan
Hebert & Uchida, PLLC
Hodes, Buckley, McGrath & LeFevre, PA
Lotter & Bailin, PC
Mazerolle & Frasca, PA
McDonald & Kanyuk, PLLC
McLane, Graf, Raulerson & Middleton, PA
McNeil & Taylor, PA
Nadeau Law Offices
Orr & Reno, PA
Ransmeier & Spellman, P.C.
Riley & Fay, PLLC
Routhier, Donald Law Offices
Sarrouf, Tarricone & Flemming
Sheehan Phinney Bass & Green, PA
Stark, Rodney L., PA
Sullivan & Gregg, PA
Sulloway & Hollis, PA
Tardif, Shapiro & Cassidy, PA
Upton & Hatfield, LLP
Vittek Law Offices
Wadleigh, Starr & Peters, PLLC
Wiggin & Nourie, PA
Winer & Bennett, LLP
Wrigley, Weeks & Martin, PC

Liberty Utilities

Capital Project Business Case 2020

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview

Project Name:	Rockingham Substation	**Date Prepared:**	2/1/2020
Project ID#:	8830-1964	**Cost Estimate:**	$400,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	3/1/2020
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2020
Prepared By:	Joel Rivera	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115kV supply lines, 115/13.2 kV - 33/44/55 MVA transformers, two 7.2 MVAR capacitor banks and 13.2kV metal clad switchgear. The new Rockingham Substation will be constructed at company owned land, neighboring the Tuscan Village Development. This substation will allow the retirement of the Salem Depot Substation given its issues with age and condition of the assets.

In 2020 it is planned to complete the design and procurement phase of the substation project. It will also include substation site work.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment, particularly in the Tuscan Village Development. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The new demand from the development is estimated at 17 MW. The loading of the system will increase to where various components (feeders, transformers and supply lines) will exceed certain planning and operating criteria. For a list of planning criteria violations expected to be exceeded with the upcoming load expansions see 2022 Planning Criteria Violations – Salem Area.pdf

See related projects Rockingham Transmission Supply and Rockingham Distribution Feeders.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed Tuscan Village Development in the range of 17MW located at the former Rockingham Park Track.

This project will provide the required capacity to supply the upcoming customer expansions and will resolve all identified criteria violations for the town of Salem. It will also resolve all issues with asset condition at the Salem Depot Substation and make way for future investments in distribution automation and grid modernization.

This business case covers Phase 2 of the Salem Area Study which installs new Rockingham #21 Substation.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

Liberty Utilities

Capital Project Business Case 2020

This project is part of the Salem Area Study. For details on alternatives considered refer to Appendix A and Section 4 of the Salem Area Report.

Financial Assessment/Cost Estimates

(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2020	2021	Beyond 2021	Total
Internal Labour (including labour and travel)	$ -	$ 25,000	$ -	$ -	$ 25,000
Materials (including consumables)	$ -	$ 250,000	$ -	$ -	$ 250,000
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (including consultants)	$ -	$ 125,000	$ -	$ -	$ 125,000
AFUDC ($)					
Total Project Costs ($)	$ -	$ 400,000	$ -	$ -	$ 400,000

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule

(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	4/31/2020
Construction	6/30/2020	12/31/2020

Risk Assessment

(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits. The risk of equipment failure due to age and condition of the Salem Depot substation assets will increase if this project is delayed. The ability for the Company to restore load during emergencies and the ability to re-route power to perform routine maintenance will be compromised if this project is not completed or is delayed.

This project is needed to support the construction of the second 115kV line which is slated to begin in the fall of 2021. This project will enable reducing the loading on the 23kV supply system that will allow the necessary outages to construct the second 115kV line. As loading in the development continues to increase, delays on this project will further increase difficulties in obtaining planned outages to safely construct new facilities.

This project has a risk score of 50.

Liberty Utilities
WATER · GAS · ELECTRIC

Capital Project Business Case

2020

Trade Finance (Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)
Unknown

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)
Please reference the following supporting documents: 2022 Planning Criteria Violations - Salem Area.pdf Salem Area Study Report.pdf 23kV Supply System Salem.pdf Rockingham Substation Project Schedule and One-Line.pdf

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering		03/04/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering		2/25/2020
Senior Vice President/ Vice President	Up to $500,000	Richard MacDonald Vice President, Operations		2/21/2020
State President:	Up to $500,000	Susan Fleck President, NH		2/26/2020
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Capital Project Business Case 2019

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation	**Date Prepared:**	1/9/2019
Project ID#:	8830-1964	**Cost Estimate:**	$200,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2019
Prepared By:	Joel Rivera	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.

In 2019 it is planned to design the installation of the 115kV line structures, 13.2kV metal clad switchgear and two 115/13.2kV transformers at the new substation site.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase or worsening of components exceeding planning and operating criteria.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track.

The recommended plan accomplishes all system capacity and asset replacement requirements. Upon completion of the projects within the Salem Area Study, Baron Ave and Salem Depot substations will be retired. The plan will be achieved in three (3) phases. This business case is for Phase 2 of the Salem Area Study.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Liberty Utilities
WATER · GAS · ELECTRIC

Capital Project Business Case 2019

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2018	2019	Beyond 2019	Total
Internal Labour (including labour and travel)	$ -	$ -	$ 10,000	$ -	$ 10,000
Materials (including consumables)	$ -	$ -	$ -	$ -	$ -
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (including consultants)	$ -	$ -	$ 190,000	$ -	$ 190,000
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade for design activities on this project. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	12/31/2019

Risk Assessment
(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Joel Rivera		3/5/19
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering		3/5/19
Senior Vice President/ Vice President	Up to $500,000			
State President:	Up to $500,000			
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		3/7/19

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Capital Project Expenditure Form 2019

Project Name:	Rockingham Substation		
Financial Work Order (FWO):		**Project ID #:**	8830-1964
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	1/9/2019
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2019
Prepared by:	Joel Rivera	**Requested Capital ($)**	$200,000
Planned or Unplanned Projects:	☒ Planned ☐ Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.

In 2019 it is planned to design the installation of the 115kV line structures, 13.2kV metal clad switchgear and two 115/13.2kV transformers at the new substation site.

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

No

What alternatives were evaluated and why were they rejected?

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Liberty Utilities

Capital Project Expenditure Form 2019

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Complete the Financial Summary table only if:

- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year		**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐ 1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: [i]	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)			

Liberty Utilities — Capital Project Expenditure Form | 2019

Approvals and Signatures [ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Joel Rivera	JRR	3/5/19
Senior Manager:	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	C. Rodrigues	3/5/19
Senior VP/VP:	Up to $500,000			
State President:	Up to $500,000			
Regional President:	Up to $3,000,000			
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration:	All Requests	Peter Dawes VP, Finance & Administration	Peter Dawes	3/7/19

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23	Date of Response: 9/15/23
Request No. DOE 6-19	Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-1, 2021 Capital Projects, Rockingham Substation, Change Order Form dated 4/05/2021.

a. Please provide an itemized breakdown with descriptions of the $4 million in additional expenditures for the project.
b. Given that the elevation grade change was due to Tuscan Development's error, why didn't Liberty hold Tuscan accountable for the extra project costs resulting from the error? Did Liberty ever approach Tuscan about this issue?
c. Given that the size and weight of the new transformers were known to Liberty prior to installation, why were the costs of the pilons not anticipated by Liberty during design and planning.

RESPONSE:

a. The original estimate of the substation project was based on costs for previously completed similar projects and not on bids based on preliminary designs. The table below depicts the breakdown of the $4 million in additional expenditures. Due to the Company providing revised drawings incorporating the change in elevation to the potential bidders during the competitive bid process, the Company is unable to determine the cost added to account for the change in the substation elevation. That is, the Company did not receive bids prior to the elevation change to enable the requested cost breakdown.

are incurred. However, when the training costs involved relate to facilities that are not conventional in nature, or are new to the service company's operations, these costs may be capitalized until the time that the facilities are ready for functional use. As stated in part (a) of this response, utilizing a distribution automation controller as part of the distribution automation scheme was the first implementation of this technology on the Company's system, and therefore, the Company capitalized the training costs in accordance with CFR § 367.83

c. Per the approved business case, the following estimated project cost breakdown is confirmed: $25,000 for internal labor, and $100,000 for subcontractor labor, resulting in a total project cost of $125,000.

    i. The estimated internal cost of $25,000 did not increase to $47,929.31. Per the project closeout form, the internal labor was $4,240.96. Burdens of $43,688.35 were applied to this project as a result of direct charges from both internal labor and contractor charges.

    ii. The contractor cost did not increase from $100,000 to $176,866. The $176,866 is due to a timing issue between the reversal of an accrual for an invoice in the amount of $88,433 and the actual invoice (in the same amount) being applied to the project. The double counting of this invoice resulted in the contractor costs being reported as $176,866. The total contractor costs, which include other external resources besides SEL, were $118,227.

    iii. As stated in part c.ii of this response, the total external contractor cost was $118,227. The amount from SEL, which includes labor costs to set up the automation system, program the devices, and provide troubleshooting support was $110,122. Contractor costs associated with the test and commissioning of the system were $6,380 and $1,725 was associated with traffic control.

    iv. Of the $110,122 from SEL, $4,160 was associated with training the Company's staff.

Capital Project Expenditure Form 2020

Project Name:	Rockingham Substation		
Financial Work Order (FWO):		**Project ID #:**	8830-1964
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	1/10/2020
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2020
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2020
Prepared by:	Joel Rivera	**Requested Capital ($)**	$400,000
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.

In 2020 it is planned to complete the design and procurement phase of the substation project. It will also include substation site work.

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

The scope of this project is to install a new 115kV – 13.2 kV Substation. There will be no equipment removed associated with this project. Therefore, this section does not apply.

What alternatives were evaluated and why were they rejected?

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Capital Project Expenditure Form 2020

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Complete the Financial Summary table only if:

- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year		**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: i	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$400,000		

Liberty Utilities

Capital Project Expenditure Form 2020

Approvals and Signatures [ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	03/09/2020
Senior Manager:	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	CA Rodrigues	2/25/2020
Senior VP/VP:	Up to $500,000	Richard MacDonald Vice President, Operations	Richard MacDonald	2/21/2020
State President:	Up to $500,000	SUSAN FLECK PRESIDENT		3/12/2020
Regional President:	Up to $3,000,000			
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration:	All Requests	Peter Dawes VP, Finance & Administration		

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Project Overview			
Reason for Change: Reference 2019 Capital spend report. GSE capital portfolio reallocated mid-year.			
Project ID:	8830-1964	**Project Name:**	Rockingham Substation
Change Order Name:	Rockingham Substation 2019 #1	**Date Prepared:**	8/3/2023
Change Order #:	8830-1964 #1	**Financial Work Order (FWO):**[i]	
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2023
Prepared By:	Ryan Patnode	**Change Type**[iii]	X In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$200,000**		**$200,000**	**$400,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Reference 2019 Capital spend report. GSE capital portfolio reallocated mid-year.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000			
State President / Senior VP / VP:	Up to $500,000	Neil Proudman NH President		
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities WATER | GAS | ELECTRIC

Change Order Form

2020

Project Overview			
Reason for Change: Budget Increase to fund project to accommodate work associated with Rockingham Substation			
Project ID:	8830-1964	**Project Name:**	Rockingham Substation
Change Order Name:	Budget Increase	**Date Prepared:**	07/27/2020
Change Order #:	8830-1964-01	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2020
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$400,000**		**$150,000**	**$550,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount: *Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc*)
Additional funding is requested to account for increase in costs associated with the Revised Salem Area Study as required per the NHPUC in Order Number 26,377.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	**New Forecast (NF)**	**Variance (BL – NF)**
N/A	N/A	N/A

Liberty Utilities
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Change Order Form

2020

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	07/27/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering		
State President / Senior VP / VP:	Up to $500,000	Richard MacDonald, VP Operations		
Regional President:	Up to $3,000,000	Susan Fleck President, NH		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities WATER | GAS | ELECTRIC

Change Order Form

2020

Project Overview			
Reason for Change: Budget Increase to fund project to accommodate work associated with Rockingham Substation			
Project ID:	8830-1964	**Project Name:**	Rockingham Substation
Change Order Name:	Budget Increase	**Date Prepared:**	11/04/2020
Change Order #:	8830-1964-02	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2020
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$400,000**	**$150,000**	**$350,000**	**$900,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc)
Previous change order amount was for additional funding to account for increase in costs associated with the Revised Salem Area Study as required per the NHPUC in Order Number 26,377. This change order amount of $350,000 was due to an intentional reallocation of funds from project 8830- 1944. Construction for project 8830-1944 was postponed and the remaining capital funds were transferred to this project for material procurement.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)
N/A	N/A	N/A

Liberty Utilities WATER | GAS | ELECTRIC

Change Order Form

2020

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	11/04/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2020.11.05 07:58:13 -05'00'	
State President / Senior VP / VP:	Up to $500,000	Richard MacDonald, VP Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2020.11.18 17:18:45 -05'00'	
Regional President:	Up to $3,000,000	Susan Fleck President, NH		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Business Case 2022

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation	**Date Prepared:**	01/03/2022
Project ID#:	8830-1964	**Cost Estimate:**	$500,000
Project Sponsor:	Christopher Steele	**Project Start Date:**	01/01/2022
Project Lead:	Melvin Emerson	**Project End Date:**	12/31/2022
Prepared By:	Melvin Emerson	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes)**:**	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Station and the retirement of Salem Depot #9 Substation.

In 2022 it is planned to paint the perimeter wall, install permanent gates, install animal protection, and perform civil work & landscaping.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase or worsening of components exceeding planning and operating criteria. In addition the testing of several substation transformers in the town of Salem have shown signs of gassing and continued deterioration.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed business park development in the range of 12MW – 18MW located at the Tuscan Village Development.

The recommended plan accomplishes all system capacity and asset replacement requirements. Upon completion of the projects within the Salem Area Study, Baron Ave and Salem Depot substations will be retired.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

For details on alternatives considered, refer to the 2020 Salem Area Study.

Liberty | Capital Project Business Case | 2022

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2021	2022	Beyond 2022	Total
Internal Labour (including labour and travel)	$ -	$ -	$ -	$ -	$ -
Materials (including consumables)	$ -	$ -	$ 100,000	$ -	**$ 100,000**
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (including consultants)	$ -	$ -	$ 400,000	$ -	**$ 400,000**
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade for design activities on this project. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	12/31/2019
Construction	4/1/2022	12/31/2022

Risk Assessment
(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.
Continued deterioration of substation assets increase the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)
Supporting Documentation can be found at W:\Engineering\Electric Engineering\Electric Planning Engineering

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Melvin Emerson Capital Lead	Melvin Emerson	01/04/2022
Senior Manager: :	Up to $50,000	Anthony Strabone Sr Manager, Electric Engineering	Anthony Strabone	01/04/2022
Senior Director/Director:	Up to $250,000	Christopher Steele Sr. Director, Electric Operations		
Senior Vice President/ Vice President	Up to $500,000			
State President:	Up to $500,000	Neil Proudman President, NH		
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Change Order Form

2022

Project Overview			
Reason for Change:	Budget Increase to fund project to accommodate work associated with Rockingham Substation		
Project ID:	8830-1964	**Project Name:**	Rockingham Substation
Change Order Name:	8830-1964 Rockingham Substation	**Date Prepared:**	11/30/2022
Change Order #:	8830-1964-1	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Anthony Strabone	**Revised Start Date:**	1/1/2022
Project Lead:	Melvin Emerson	**Revised End Date:**[ii]	12/31/2022
Prepared By:	Melvin Emerson	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☒ No	**If No is Selected, Please specify source of funds**[iv]	8830-1958 Tuscan Village Line South $160K.

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$500,000**		**$160,000**	**$660,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount: *$160,000*

Over expenditure is being driven by costs associated with work identified needing to be addressed under the Rockingham Substation Capital Specific Project. The major project expenditures necessary to complete construction and make the substation ready for service include station commissioning, animal protection, wall staining, gates, paving, and labor to monitor and complete construction of the substation. The anticipated overspend of this project will be offset by underspend of other capital projects and therefore will not impact the overall 2022 GSE Capital Budget.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	**New Forecast (NF)**	**Variance (BL – NF)**
N/A	N/A	N/A

Liberty | Change Order Form | 2022

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Melvin Emerson Capital Lead	Melvin Emerson	5 June 2023
Senior Manager:	Up to $300,000	Kedrick Robinson Manager, Engineering Projects	Kedrick Robinson	6/5/23
Senior Director/Director:	Up to $500,000	Anthony Strabone Director, Engineering & Project Management	Anthony Strabone	06/05/2023
State President / Senior VP / VP:	Up to $2,000,000	Neil Proudman NH President		
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $3,500,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $7,500,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

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Liberty | Capital Project Expenditure Form | 2022

Project Name:	Rockingham Substation		
Financial Work Order (FWO):		**Project ID #:**	8830-1964
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	12/23/2021
Project Sponsor:	Christopher Steele	**Project Start Date:**	01/01/2022
Project Lead:	Melvin Emerson	**Project End Date:**	12/31/2022
Prepared by:	Melvin Emerson	**Requested Capital ($)**	$500,000
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request Rockingham Substation

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Station and the retirement of Salem Depot #9 Substation.

In 2022 it is planned to design the installation of the second set of 115kV line structures, and complete work at the new substation site.

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

No

What alternatives were evaluated and why were they rejected?

For details on alternatives considered, refer to the 2020 Salem Area Study.

What are the risks and consequences of not approving this expenditure?

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Continued deterioration of substation assets increase the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Liberty | Capital Project Expenditure Form | 2022

Complete the Financial Summary table only if:

- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☒1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: [i]	☐Fixed or Firm Price ☒Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$500,000		

Liberty | Capital Project Expenditure Form | 2022

Approvals and Signatures [ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Melvin Emerson Capital Lead	Melvin Emerson	12/28/2021
Senior Manager:	Up to $50,000	Anthony Strabone Sr Manager, Electric Engineering	Anthony Strabone	12/28/2021
Senior Director/Director:	Up to $250,000	Christopher Steele Sr. Director, Electric Operations		
Senior VP/VP:	Up to $500,000			
State President:	Up to $500,000	Neil Proudman President, NH		
Regional President:	Up to $3,000,000			
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration:	All Requests	~~Peter Dawes~~ ~~VP, Finance & Administration~~		

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group

Liberty Utilities

Change Order Form

2021

Project Overview			
Reason for Change: Budget Increase to fund project to accommodate work associated with Rockingham Substation			
Project ID:	8830-1964	**Project Name:**	Rockingham Substation
Change Order Name:	Budget Increase	**Date Prepared:**	04/05/2021
Change Order #:	8830-1964-01	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2021
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$7,000,000**		**$4,000,000**	**$11,000,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc)

The drivers associated with this change order are as follows:
1. Burden rates: In 2020 the burden rates used, which were provided by Finance, to determine the cost of this project were 32.76% for contractor and outside vendors and 8% for direct material charges. However, per an update from Finance, the 2021 burden rates are 43% and 22% for contractor/outside services and direct material charges respectfully. This results in an overall increase of approximately 24%.

2. Elevation grade change: In early March 2021, the Tuscan Development Team made Liberty aware that there were issues with the elevations on the Tuscan parcel around the substation property. Tuscan indicated that the elevations provided to Liberty in 2018, which were used to design the substation, were lower than what was actually being encountered in the field. Based on field measurements; multiple meetings and discussions with the Substation Design Team, the best and safest alternative was chosen which was to raise the substation property on average 2FT.

Liberty Utilities

Change Order Form

2021

3. Transformer Foundations: Based on the weight and size of the transformers, the soil, which is based on a geo-technical study, in the area of the transformers is not suitable to support these units. In order to prevent these foundations from settling over time, each foundation will require 10, 30FT grout filled steel piles

4. Increase in labor and material costs from 2020 to 2021.

Schedule Impacts (As a result of the Change Order, where applicable, List the Impacts to schedule)		
Baseline Schedule (BL)	**New Forecast (NF)**	**Variance (BL – NF)**
N/A	N/A	N/A

Approvals and Signatures

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000	Anthony Strabone Senior Manager, Electric Engineering	Anthony Strabone	05/17/2021
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.05.17 13:52:34 -04'00'	
State President / Senior VP / VP:	Up to $500,000	Richard MacDonald, VP Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2021.05.24 09:01:02 -04'00'	

Liberty Utilities

Change Order Form

2021

Regional President:	Up to $3,000,000	~~Susan Fleck President, NH~~		5/26/21
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	COO		06/07/21

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[iv] In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23 Date of Response: 11/20/23
Request No: DOE TS 2-40 Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-1, 2019 - 2022 Capital Projects, Rockingham Substation, Change Order dated April 5, 2021; DOE 6-19; and Docket DE 19-064, Exhibit 21, Attachment JED-3c at Bates 421.

a. Please describe the Company's efforts in 2017 related to searching and investigating potential sites for the Rockingham Substation. Please list all of the potential locations reviewed. Also, please provide any documentation or records, including any written analysis, that details Liberty's property search and why certain sites were not selected.

b. Please explain why re-utilizing Liberty's existing substations, Salem Depot and Baron Ave., were not viable options for the Rockingham Substation. Did the Company ever contact or explore the potential purchase of the former restaurant property adjacent to Salem Depot, and if so, what were the results of those discussions?

c. When and why did Liberty approach the developer of Tuscan Village about locating the Rockingham Substation within that development? What were the developer's conditions, if any, for locating the substation within Tuscan Village?

d. A commercial appraisal of the proposed Rockingham Substation site within Tuscan Village was performed in July 2017. The appraisal concluded the market value of the lot to be $925,000. Please describe the decision-making process undertaken by Liberty that provided justification for the Company to purchase the lot at a price of $1.5 million, representing a $575,000 premium over and above the market value.

e. The contractor responsible for building the paved road to Rockingham Substation initially (2018) provided Liberty with the wrong elevation grade causing Liberty to redesign and revise the elevation of the substation at substantial additional expense to the Company and ratepayers. Did Liberty ever consider holding the contractor liable for that error? If not, why not?

f. Liberty commissioned a geotechnical study of the soils at the Rockingham site which concluded that some of the underlying soils were unstable. Please provide a copy of the geotechnical report.

g. Liberty constructed a screening wall around the perimeter of the Rockingham Substation site to conceal it from view. Please provide the following information:

Docket No. DE 23-039 Request No. DOE TS 2-40

i. Type of wall, wall height, and construction material used.
ii. Total cost of the wall.
iii. Confirm that the construction of the wall was at the request of the Tuscan Village owner and the Town of Salem.
iv. Provide a copy of the decision of the Town of Salem Planning Board including findings of fact involving approval of the construction of Rockingham Substation and the screening wall.
v. Copies of any and all communications between Liberty, the owner of Tuscan Village, and the Salem Planning Board related to the requirement of a screening wall.

h. Confirm that the second transformer was finished, energized, and taking load in 2022.

RESPONSE:

a. In 2017, the Company evaluated the properties listed below for locating the Rockingham substation.
    i. Salem Depot Substation- please see the Company's responses to part b below for why this property was not selected.
    ii. Baron Ave Substation- please see the Company's responses to part b below for why this property was not selected.
    iii. 1 Tuscan Blvd (current site of Rockingham Substation)
    iv. 60 Pleasant Street. This site is located West of the Tuscan Development. It proposed challenges with respect to routing of the 115 kV Supply lines and distribution feeders. With respect to routing of the ten (10) distribution feeders proposed with Rockingham Substation, these ten distributions feeders would either exit the Pleasant Street site overhead on multiple pole lines or underground along public rights of ways (streets/roads) which would significantly increase costs. Another challenge was that, in order to reach this site, the 115 kV Supply lines would need to be extended from the ROW and routed either through the Tuscan development, and the property of the Rockingham Mall Hampshire or along local roads/street resulting in increased costs for the supply lines. For these reasons listed, this property was not selected.
    v. Garabeddian Site- this site is located near the Salem Animal Rescue League and was the former site of the Salem Water Treatment Facility. This site was identified as containing contaminated soil which was recently treated by the Town of Salem. This site proposed challenges with respect to routing of the ten distribution feeders proposed with Rockingham Substation. These ten (10) distributions feeders would either exit the site overhead on multiple pole lines or underground along public right of ways which would increase costs. For these reasons listed, this property was not selected.

b. The Company did not contact or explore the potential purchase of the former restaurant property adjacent to Salem Depot because this restaurant was still in operation at the time the Company was evaluating potential sites for the new substation. The fire at the restaurant occurred in June 2018, which was after the Company completed its analysis of properties and around the same time the Company and Tuscan Development were finalizing the purchase and sales agreement for the current Rockingham Substation property.

   Salem Depot was not a viable option because the property where the existing substation was located was not of sufficient size to accommodate the new proposed substation. In order to utilize this property, the Company would have to purchase two adjacent residential properties and request the Town of Salem to discontinue the use of a local road near the Salem Depot property In addition to these issues, the Salem Depot property is located further North of the property where the Rockingham substation was constructed, which would require additional costs to extend the 115 KV Supply lines further North to the Salem Depot substation. Based on the property challenges and additional costs for the 115 kV line, the Company determined the Salem Depot property was not a viable option.

   Similar to Salem Depot, the Baron Avenue substation site was not a viable option because the existing property was not of sufficient size to accommodate the proposed substation. Property expansion at Baron Ave Substation was also a challenge due to existing wetlands in close proximity to the substation property. In addition to limited property expansion at Baron Ave, this site also presented challenges with respect to routing of the ten distribution feeders proposed with Rockingham Substation. These ten distributions feeders would either exit the Baron Ave site overhead on multiple pole lines through residential neighborhoods or underground along public right of ways which would significantly increase costs. Based on the property and distribution routing challenges, the Company determined the Baron Ave property was not a viable option.

c. As part of its efforts of identifying possible parcels for a new substation, the Company approached the developer of Tuscan Village in 2016 about locating the Rockingham Substation within that development. There only additional condition imposed by the developer for locating the substation within the development was screening.

d. Although the Company's commercial appraisal of the proposed Rockingham Substation site within Tuscan Village was less than the purchase price of $1.5 million, the arms' length negotiation between the Company and the developer resulted in the purchase price, -- and thus the actual market value -- of $1.5 million. The Company had determined this lot was clearly the best possible location for the new proposed substation in terms of overall cost and operational factors based on its evaluation of other locations in the area described above. There was no "premium" of $575,000 over market value. The true market value was what the Company paid because it resulted from an arms' length transaction between two sophisticated parties. Alternatively, the Company had determined that any "premium" was less than the increased construction costs that would have been associated with the other properties the Company considered.

e. The Company did not consider holding the contractor liable for the change in road elevation since Tuscan Development was only required to provide a paved road to the substation site and the elevation of the road was not identified as part of the agreement.

f. Refer to Attachment 23-039 DOE TS 2-40.f.

g. Please see the following responses:

   i. The wall is 15 feet high and is made of concrete.

   ii. Total cost of the wall is $653,608.

   iii. The original request of the Town of Salem was for a 15 FT high louvered metal fence option to provide substation screening. Upon review of cost and construction requirements of the metal fence option, the Company requested and received approval from the Salem Planning Board to use the lower cost option of a concrete wall to screen the substation instead of the metal fence.

   iv. Please see Attachment 23-039 DOE TS 2-40.g.iv for a copy of the approved substation drawings along with a letter from the Salem Planning Board approving the use of the concrete wall instead of the metal fence.

   v. Please see Attachment 23-039 DOE TS 2-40.g.v for additional correspondence related to the substation screening between the Company and the Town of Salem's consultant.

h. The second transformer was energized and taking load in 2023.

CHG
Geotechnical Engineering

October 5, 2020
CHG Job No. 2016

PLM, Inc.
35 Main Street
Hopkinton, MA 01748
Attention: Kevin Soden

Subject: Geotechnical Engineering Investigation
Rockingham Substation
Salem, NH

Dear Mr. Soden:

Charles H. Gross, PE, LLC (CHG) is pleased to submit the findings and recommendations of our geotechnical engineering investigation conducted at the above-referenced property for the proposed site improvements at the above address.

Thank you for engaging our services for this project. If you have any questions, please do not hesitate to call.

Very truly yours,
Charles H. Gross, PE, LLC

STATE OF NEW HAMPSHIRE
CHARLES H. GROSS
NO. 10194
LICENSED
PROFESSIONAL ENGINEER

Charles H. Gross, PE, M.ASCE
Manager

Attachments

Table of Contents

		Page
1.0	**GENERAL**	**3**
1.1	Authorization	3
1.2	Project Description	3
1.3	Purposes and Scope of the Investigation	3
2.0	**SITE CONDITIONS**	**4**
2.1	Surface Conditions	4
2.2	Subsurface Conditions	4
2.3	Groundwater	5
3.0	**FINDINGS, CONCLUSIONS AND RECOMMENDATIONS**	**6**
3.1	General	6
3.2	Foundation Support	6
3.3	Site Preparation	8
3.4	Groundwater Control During Construction	9
3.5	Stability of Excavations	9
3.6	Excavations and Preparation of Bearing Surfaces	10
3.7	Backfill and Compaction	10
3.8	Seismic Design	12
3.9	Suitability of On-Site Material for Fill	12
4.0	**LIMITATIONS**	**13**

Attachments:

Figure 1 – Locus Plan
Figure 2 – Test Boring Plan

Appendix A – Test Boring Logs

1.0 GENERAL

1.1 Authorization

In accordance with your authorization we have undertaken and completed our subsurface investigation and prepared this Geotechnical Engineering Report. Refer to Figure 1 in this report for a locus plan.

1.2 Project Description

The project consists of constructing electrical equipment in the general area where test borings were drilled on September 4, 2020. PLM provided CHG with the boring locations shown on Figure 2.

Borings B-1, B-2 and B-3 are the locations for future caisson foundations that are anticipated to be 6'-0" in diameter. B-4 and B-5 are at proposed power transformers. Boring B-6 is at the 13.2 kV Switchgear assembly.

1.3 Purposes and Scope of the Investigation

The purposes of this investigation are to define and evaluate the subsurface conditions beneath the proposed construction and provide recommendations for the foundation and earthwork activities, including recommendations for allowable soil bearing capacity and seismic site profile classification. To accomplish these tasks, the following scope of services was performed:

- Performed a visual Site inspection by our Geotechnical Engineer;
- Engaged a boring contractor to drill 6 test borings;
- Monitored the test boring operations;
- Collected soil samples and measured groundwater levels in the field;
- Logged and classified soil samples; and
- Submitted this report of our findings, conclusions and recommendations.

2.0 SITE CONDITIONS

2.1 Surface Conditions

At the time of our investigation, the Site was relatively level and vacant.

2.2 Subsurface Conditions

As part of this investigation test borings were drilled under the supervision of Charles H. Gross, P.E. to explore the Site's subsurface conditions. Test boring locations are shown on Figure 2. Mr. Gross classified soil samples in the field based on visual and textural examination using the Unified Soil Classification System.

Soil X Corp of Leominster, MA drilled 6 test borings. The borings were drilled using rotary drill rigs. Standard Penetration Tests[1] (SPT) were performed at intervals noted on the boring logs. Soil samples were collected from the ground surface to the maximum depth explored, which was 32 ft below existing grade. Test boring logs are included in Appendix A.

Our knowledge of the subsurface conditions beneath the proposed construction area is based on the findings in the test borings. The following generalized subsurface strata were encountered starting from the ground surface:

- **Fill,** consisting of Silty Sand (SM[2]) and Gravelly Sand (SP-SM), was encountered at the ground surface. The Fill extended to a depth of 5 ft in the test borings. The Fill was very loose to dense with SPT N-values ranging from 10 to 38 blows; however, it was primarily medium dense.
- **Peat (PT)** , approximately 3 ft thick, was encountered directly beneath the Fill in test boring B-6. The Peat was very soft with an SPT N-value of 2 blows.
- **Native Granular Soils** were encountered directly beneath the Fill. The Native Granular Soils consisted of Silty Sand (SM), Sand (SP-SM), and Sandy Silt (ML) and extended to the maximum depths explored, which was 32 ft below existing

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[1] SPT N-Value is the number of blows for the drill rigs automatic hammer required to advance the standard 1-3/8 inch I.D. by 2.0 inch O.D. split-spoon sampler the last 12 inches of an 18-inch sampling interval.

[2] Symbols used on the test boring logs are explained as follows:

SP-SM:	Poorly graded Sands with 5 to 12% ML or MH fines
SM:	Sands with greater than 12% ML or MH fines
Pt:	Organic soils with a distinctive organic texture and containing particles of leaves, grass, branches or other fibrous vegetative matter.
ML:	Inorganic nonplastic and slightly plastic Silts and medium plastic Clayey Silts
MH:	Inorganic slightly plastic Silts and medium plastic to very plastic Clayey Silts

grade. The soils were loose to very dense with SPT N-values ranging from 5 to greater than 59 blows.

2.3 Groundwater

The groundwater levels in the borings varied from approximately 8 to 10 ft below existing grade.

The groundwater level may be affected by local anomalous conditions as well as seasonal factors and thus, may not represent the level to be encountered in the future. Generally, groundwater levels are highest in the early spring and lowest in the late fall.

3.0 FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

3.1 General

The geotechnical concerns for the Site are the following:

- All foundation units be founded on similar bearing strata;
- Possible softening of the bearing strata due to construction operations and rainfall runoff;
- The suitability of on-Site materials for re-use as compacted fills; and

To avoid construction delays, we recommend preparing an as-built utility plan during the design phase of this project. The as-built utility plan will help the design team prepare foundation plans and specifications minimizing construction delays and potential utility damage.

3.2 Foundation Support

Geotechnical design parameters for soils in Section 2.2 include the following:

- Allowable bearing capacity of the medium dense Native Granular Soils = 3 ksf;
- Approximate unit weight of compacted Fill Soils = 120 pcf
- Approximate unit weight of Native Granular Soils = 120 pcf;
- Angle of internal friction of Native Granular Soils = 30 degrees;
- Coefficient of friction between Native Granular Soils and concrete = 0.4;
- Coefficient of friction between Processed Gravel Fill and concrete = 0.45;
- Coefficient of active earth pressure = 0.33;
- Coefficient of passive earth pressure = 3.0;
- Coefficient of earth pressure at rest = 0.5;
- Subgrade Modulus = 125 pci
- Equivalent fluid unit weight of the Native Granular Soils equal to 120 pcf to calculate passive pressures above water table;
- For design purposes of caissons, the upper 4 feet of soils should not be considered for skin friction values; and
- Hydrostatic uplift is not a concern for the proposed structures based on the depth groundwater was encountered.

6 ft dia. Caisson Foundations (B-1, B-2, & B-3)

CHG recommends that future caisson foundations be supported on the medium dense to dense Native Granular Soils. Considering the presence of wet sand, we recommend that the contractor be prepared to provide temporary casing to support the walls of the caisson shaft during drilling. The concrete should be cast-in-place directly against the Native Granular Soils.

We recommend the caissons be founded below the loose Native Granular Soils in boring B-1 & B-2 at 25 ft and B-3 at 30 ft below existing grade on the medium dense to dense sands. The net allowable bearing capacity of the medium dense Native Granular Soils is 3 ksf

For design purposes, total caisson settlements are estimated to be less than 1 inch and the differential settlement will be considerably less and should pose no significant structural problems.

Power Transforms & Switchgear Assembly (B-4, B-5, & B-6)

We do not recommend a shallow foundation scheme at these boring locations due to the presence of loose to medium dense soils consisting of the Fill, Peat, and Native Granular Soils mentioned in Section 2.2. In borings B-4, B-5, and B-6 these soils extended to a depth of approximately 20, 25, and 10 ft, respectively. The Fill is considered unsuitable for foundation support because there is no documentation provided indicating that it was placed in lifts, properly compacted, and tested. The organic Peat is unsuitable for foundation support because it is highly compressible.

CHG recommends considering a deep foundation system consisting of helical piles to support the proposed power transformers and switch gear assembly. We recommend engaging a Geotechnical Specialty Contractor for design and installation of the helical piles.

The helical piles are advanced into the ground using a rotary motor typically mounted to a backhoe or excavator. As the pile lead is advanced, additional extension sections are added as required. The lead section is advanced through the unsuitable soils into the underlying suitable medium dense Native Granular Soil bearing materials. The supported loads are transferred to the underlying suitable material via the pile shaft.

CHG recommends that the Geotechnical Specialty Contractor consider a grout-encased shaft style pile known as a Helical Pulldown Micro-pile (HPM). A helical pile with a grouted shaft provides an additional benefit as it introduces a friction component to the pile, which increases its overall capacity. The grouted portion of the pile develops friction along the interface with the displaced soil surrounding it, which contributes to the pile capacity.

The HPM consists of a conventional helical pile that is encased in a shaft of neat cement grout. The pile extensions are fitted with plates that displace the surrounding soil as the pile is advanced. A reservoir is used at the surface to maintain a head of grout above the pile. As the HPM is advanced, the grout is drawn down with the pile forming a continuous shaft. The grouted shafts typically have diameters on the order of 4 to 6 inches.

For this project, it is anticipated that a properly configured helical pile (length up to 32 ft) with a continuous shaft installed into the underlying medium dense Native Granular Soils could develop an allowable (working load) capacity up to 5 to 10 tons. We recommend the Geotechnical Specialty Contractor perform a pile load test(s) verifying the achieved working load and submit the results to the Owner's representative prior to installing production piles. In addition, we recommend the Contractor submit documentation verifying the as-built design capacity and depth of embedment of each pile immediately after it is installed to the Owners representative on-site.

For design purposes, total helical pile settlements are estimated to be less than 1 inch and the differential settlement will be considerably less and should pose no significant structural problems.

3.3 Site Preparation

If encountered, all old foundations (i.e., concrete slabs, walls, and footings) and any old sewage disposal system are unsuitable for foundation support and must be removed and then backfilled with compacted Granular Fill, crushed stone or combination thereof, as specified in Section 3.7, up to design grade. It is also recommended that existing foundations be removed beneath proposed utilities, exterior slabs, and pavement.

3.4 Groundwater Control During Construction

Groundwater was encountered in the test borings and varied from 8 to 20 feet below existing grade. However, it should be anticipated that groundwater control might be required at this Site during the excavation and backfilling operations. Groundwater infiltration into the excavation may be substantial during periods of heavy or prolonged rainfall and in the springtime of the year. Trapped groundwater in the on-site soil layers may be encountered in the excavation. Groundwater control may be accomplished with the use of sumps, ditches and pumps.

In all excavations where groundwater is encountered, it is essential that the foundation-bearing surface be protected against softening due to traffic of workmen and equipment. We recommend that groundwater be lowered a minimum of 2 feet below the bottom of the proposed excavation and that all bearing surfaces be protected against disturbance by placing a minimum 6 inch thick layer of ¾ Inch Minus Crushed Stone Fill. The stone layer should be compacted by making at least 6 passes with a hand operated vibratory plate compactor under the observation of a Geotechnical Engineer.

Surface drainage should be directed away from the excavation during construction so that the bearing surface does not become softened by water flow or puddling. This can be accomplished with proper grading or construction of small dikes at the edge of the excavation. The Site should be graded so that surface water will not accumulate, as soils will soften and lose strength.

3.5 Stability of Excavations

The Contractor is responsible for construction site safety and should be aware that slope height, slope inclination and excavation depths should in no case exceed those specified in local, state or federal safety regulations (i.e., OSHA Health and Safety Standards for Excavations, 29 CFR Part 1926) Soil stockpiles should be maintained at least 5 feet from the edge of excavations. A trench shield would be an appropriate excavation support tool to use on this project.

Design of temporary and permanent cut slopes should be in accordance with pertinent OSHA and local safety regulations. Excavations deeper than 5 feet require bracing, shoring or flattening of slopes. Permanent excavations (those planned to be left open more than one month) should be no steeper than 2.5 horizontal to 1 vertical in the overlying soils.

3.6 Excavations and Preparation of Bearing Surfaces

The Site overburden soils can be excavated by hydraulic backhoe or other conventional earth moving equipment based on the conditions encountered in our subsurface investigations.

Unstable areas, which may appear during compaction, should be excavated and replaced with ¾ Inch Minus Crushed Stone Fill, compacted Processed Gravel Fill, and/or compacted Granular Fill. Refer to Section 3.7 for ¾ Inch Minus Crushed Stone Fill gradation recommendations. If more than a 6 inch thickness of crushed stone is required to reach bottom of footing grade, the crushed stone should be completely wrapped in Mirafi 140N filter fabric, or equivalent, to mitigate migration of the fine soils into the voids of the crushed stone. Migration of fines could result in significant settlement of foundations. The crushed stone should be compacted by making at least 6 passes with a hand operated vibratory compactor under the observation of a Geotechnical Engineer.

3.7 Backfill and Compaction

Gradation of Granular Fill – Backfill beneath footings, slabs, and adjacent to walls should consist of compacted Granular Fill. This fill should consist of well graded natural sand and gravel, free from plastic fines, organic matter and deleterious material and should have the following gradation:

Gradation of Granular Fill

U.S. Sieve Size & Number	Percent Passing Maximum	Percent Passing Minimum
2 inch	---	100
1 inch	100	60
No. 4	85	25
No. 20	60	10
No. 50	35	4
No. 200	10	3

Processed Gravel Fill – This fill should consist of well-graded processed gravel and sand, free from plastic fines, organic matter and deleterious material and should have the following gradation:

U.S. Sieve Size & Number	Percent Passing Maximum	Percent Passing Minimum
3/4 inch	---	100
No. 4	85	40
No. 200	10	0

¾ Inch Minus Crushed Stone Fill – We recommend the following gradation:

U.S. Sieve Size & Number	Percent Passing Maximum	Percent Passing Minimum
1 inch	---	100
3/4 inch	100	90
1/2 inch	50	10
3/8 inch	20	---
No. 4	5	---

Within the areas excavated for footings, walls, and other limited areas where large compaction equipment cannot work, we recommend that the fill be placed in loose lifts no more than 4 inches in thickness and be compacted with hand manipulated machines such as pneumatic compactors, vibratory plate compactors, etc. In open areas where a 10-ton vibratory roller can be used, we recommend that the loose lift thickness not exceed 12 inches. Fill should be compacted within 2 percent of the optimum moisture content to a minimum of 95% of the maximum dry density as determined by the test designated ASTM D1557.

In soil load bearing areas, prior to placing any structural concrete or fill, the excavated surfaces should be cleaned of all loose or disturbed material. The resulting subgrade should then be proof-rolled with at least 6 passes each way using a vibratory compactor to minimize settlements of in-situ material locally disturbed during the excavation operations. A Geotechnical Engineer prior to placement of concrete or compacted fill should inspect all bearing surfaces.

3.8 Seismic Design

With regard to seismic design, the Site should be considered a Site Class D in accordance with Table 1613.2 of the 2015 International Building Code.

It is our opinion that the native soils encountered in the subsurface explorations that are directly beneath the proposed construction, as well as the compacted fill materials, will have sufficient density to preclude liquefaction or excessive dynamic settlement during the postulated seismic event.

It is our opinion that the native soils encountered in the test borings that are directly beneath the proposed construction, as well as the compacted fill materials, will have sufficient density to preclude liquefaction or excessive dynamic settlement during the postulated seismic event.

3.9 Suitability of On-Site Material for Fill

Only the on-site Sands (SP-SM) described in Section 2.2 without any deleterious and/or organic matter are suitable for re-use as compacted fill up to within 12 inches of the bottom of footings.

We do not recommend using the on-Site Silty Sand (SM) beneath structures, footings, and slabs because:

- they are very sensitive to disturbance due to changes in water content and construction traffic;
- they are frost susceptible, which means proper placement of these materials during freezing weather (winter conditions) will be difficult to achieve;
- they poorly drain beneath proposed pavement sections; and
- they are very difficult to work with during rainy weather and it may be necessary to dry out the near surface soils after a rainstorm by mixing and drying.

4.0 LIMITATIONS

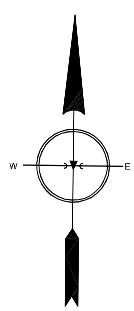
All the professional opinions presented in this report are based solely on the scope of work conducted and sources referred to in our report. The data presented by CHG in this report was collected and analyzed using generally accepted industry methods and practices at the time the report was generated. This report represents the conditions, locations, and materials that were observed at the time the fieldwork was conducted. No inferences regarding other conditions, locations, or materials, at a later time may be made based on the contents of the report. No other warranty, expressed or implied, is made.

This report was prepared for the sole use of our client. The use of this report by anyone other than our client or CHG is strictly prohibited without the express prior written consent of CHG. Portions of the report may not be used independently of the entire report.

The above recommendations and conclusions are based on our evaluation of the obtained data presented in the text. We would welcome the opportunity to monitor the pertinent phases of the foundation construction; thus, if differences are found between the field conditions described herein and those encountered during construction, we can modify our recommendations in a timely and professional manner.

ATTACHMENTS

FIGURES



Locus Plan
Rockingham Substation
Salem, NH

Charles H. Gross, PE, LLC
23 Liberty Circle, Hanson, MA
Tel: 617-909-5180

Dr. By CHG	Scale: As Shown	Figure No. 1
Ck'd. By CHG	Date: 9/14/20	Project No. 2016

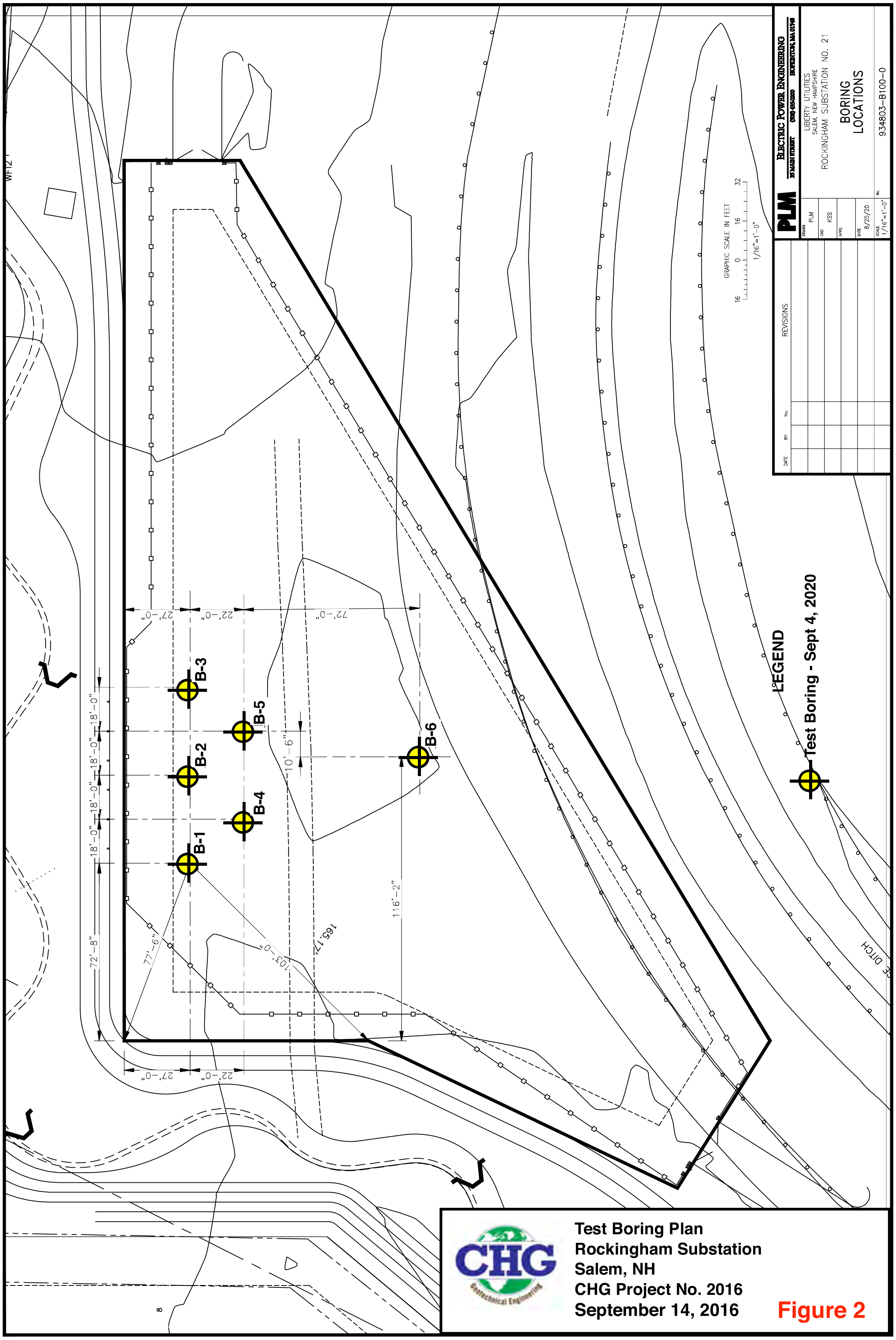

B-1
B-2
B-3
B-4
B-5
B-6
LEGEND
Test Boring - Sept 4, 2020
ELECTRIC POWER ENGINEERING
LIBERTY UTILITIES
SALEM, NEW HAMPSHIRE
ROCKINGHAM SUBSTATION NO. 21
BORING LOCATIONS
934803-B100-0
REVISIONS
GRAPHIC SCALE IN FEET
CHG
Geotechnical Engineering
Test Boring Plan
Rockingham Substation
Salem, NH
CHG Project No. 2016
September 14, 2016

Figure 2

APPENDIX A
TEST BORING LOGS

CHG Geotechnical Engineering

Project Name: **Rockingham Substation**		Boring No. **B-1**
Project Location: **Salem, New Hampshire**		Sheet 1 of 1
Project Number: **2016**		Location: See Figure 2
Boring Contractor: **Soil X Corp**		Approx. Elev.

Groundwater Observations

Date	Time	Depth
9/4/20	Completion	10'

	Casing	Sampler	Core
Type	Auger	Split Spoon	
Size I.D.	4-¼"	1-3/8"	
Hammer Wt.	Automatic Hammer		
Hammer Fall			

Date Start: 9/4/20
Date Finish: 9/4/20
Driller: D. Ledger
Inspector: C. Gross
Rig Type: M0bile B-57

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/22	0 - 2	7-15-14-10	**Fill: Silty Sand (SM):** c/f sand, 15-25% npf, light brown, dry.
	S-2	24/11	2 - 4	7-8-9-5	**Fill: Silty Sand (SM):** m/f sand, 12-20% npf, brown & dark brown, dry. 5'
5'	S-3	24/23	5 - 7	8-10-14-16	**Sand (SP-SM):** fine sand, 5-12% npf, orange-brown, moist 7'
	S-4	24/22	7 - 9	8-9-8-9	**Silty Sand (SM):** fine sand, 12–20% npf, light brown, moist. 9'
10'	S-5	24/19	10 - 12	2-4-5-6	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist 14'
15'	S-6	24/22	15 - 17	3-5-5-6	**Silty Sand (SM):** fine sand, 12–20% npf, brown, wet.
20'	S-7	24/12	20 - 22	2-3-3-4	**Silty Sand (SM):** fine sand, 12-20% npf, brown, wet. 23'
25'	S-8	24/15	25 - 27	16-18-22-20	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray-brown, wet
30'	S-9	24/20	30 - 32	12-14-19-14	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 20-30% npf, gray-brown, wet
					End of Boring @ 32'

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

CHG Geotechnical Engineering	Project Name: **Rockingham Substation** Project Location: **Salem, New Hampshire** Project Number: **2016** Boring Contractor: **Soil X Corp**	Boring No. **B-2** Sheet 1 of 1 Location: See Figure 2 Approx. Elev.

Groundwater Observations

Date	Time	Depth
9/4/20	Completion	10'

	Casing	Sampler	Core
Type	Auger	Split Spoon	
Size I.D.	4-¼"	1-3/8"	
Hammer Wt.	Automatic Hammer		
Hammer Fall			

Date Start: 9/4/20
Date Finish: 9/4/20
Driller: D. Ledger
Inspector: C. Gross
Rig Type: M0bile B-57

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/20	0 - 2	10-16-10-9	**Fill: Gravelly Sand (SP-SM):** c/f sand, 5-15% fine gravel, 5-12% npf, brown, dry.
	S-2	24/19	2 - 4	5-6-5-5	**Fill: Silty Sand (SM):** fine sand, 12-20% npf, light brown, dry. 5'
5'	S-3	24/22	5 - 7	6-8-14-10	**Sand (SP-SM):** fine sand, 5-12% npf, orange-brown, dry
	S-4	24/17	7 - 9	10-14-16-10	**Sand (SP-SM):** fine sand, 5-12% npf, orange-brown, dry 9'
10'	S-5	24/18	10 - 12	3-3-2-3	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, wet 14'
15'	S-6	24/20	15 - 17	4-7-7-7	**Silty Sand (SM):** fine sand, 12–20% npf, light brown, wet. 19'
20'	S-7	24/12	20 - 22	2-3-3-4	**Silty Sand (SM):** fine sand, 12-20% npf, light brown, wet. 24'
25'	S-8	24/19	25 - 27	8-7-10-12	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 15-25% npf, light brown, wet 28'
					Gravelly Sand (SP-SM): c/f sand, 10-15% fine gravel, 5-12% npf, gray-brown, wet
30'	S-9	7/7	30 - 30.7	37-100/1"	**End of Boring @ 30.7'**

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

CHG Geotechnical Engineering

Project Name: **Rockingham Substation**
Project Location: **Salem, New Hampshire**
Project Number: **2016**
Boring Contractor: **Soil X Corp**

Boring No. **B-3**
Sheet 1 of 1
Location: See Figure 2
Approx. Elev.

Groundwater Observations

Date	Time	Depth
9/4/20	Completion	10'

	Casing	Sampler	Core
Type	Auger	Split Spoon	
Size I.D.	4-¼"	1-3/8"	
Hammer Wt.	Automatic Hammer		
Hammer Fall			

Date Start: 9/4/20
Date Finish: 9/4/20
Driller: D. Ledger
Inspector: C. Gross
Rig Type: M0bile B-57

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/20	0 - 2	10-15-8-7	**Grass overlying Fill: Gravelly Sand (SP-SM):** c/f sand, 5-15% fine gravel, 5-12% npf, brown, dry.
	S-2	24/2	2 - 4	8-8-10-8	**Fill: Silty Sand (SM):** fine sand, 12-20% npf, light brown, dry.
					5'
5'	S-3	24/18	5 - 7	5-8-8-9	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, dry
	S-4	24/22	7 - 9	8-9-8-9	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist
					9'
10'	S-5	24/20	10 - 12	4-4-5-5	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, wet
					14'
15'	S-6	24/19	15 - 17	5-7-8-10	**Silty Sand (SM):** fine sand, 12–20% npf, light brown, wet.
20'	S-7	24/19	20 - 22	5-5-5-5	**Silty Sand (SM):** fine sand, 20-30% npf, light brown, wet.
					24'
25'	S-8	24/6	25 - 27	10-5-6-5	**Sand (SP-SM):** c/f sand, 5-10% fine gravel, 5-12% npf, brown, wet
					28'
30'	S-9	14/10	30 - 31.2	30-31-100/2"	**Silty Sand (SM):** c/f sand, 10-15% fine gravel, 15-25% npf, gray-brown, wet
					End of Boring @ 31.2'

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

CHG Geotechnical Engineering		
	Project Name: **Rockingham Substation** Project Location: **Salem, New Hampshire** Project Number: **2016** Boring Contractor: **Soil X Corp**	Boring No. **B-4** Sheet 1 of 1 Location: See Figure 2 Approx. Elev.

Groundwater Observations				Casing	Sampler	Core	
Date	Time	Depth	Type	Auger	Split Spoon		Date Start: 9/4/20
9/4/20	Completion	9'	Size I.D.	4-¼"	1-3/8"		Date Finish: 9/4/20
			Hammer Wt.	Automatic Hammer			Driller: P. Goodale
			Hammer Fall				Inspector: C. Gross
							Rig Type: CME-75 ATV

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/21	0 - 2	8-12-15-10	**Fill: Silty Sand (SM):** c/f sand, 12-20% npf, light brown, dry.
	S-2	24/18	2 - 4	6-5-5-4	**Fill: Silty Sand (SM):** m/f sand, 12-20% npf, brown, dry.
					5'
5'	S-3	24/21	5 - 7	15-28-31-38	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist
	S-4	24/18	7 - 9	18-22-19-24	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist
					9'
10'	S-5	24/21	10 - 12	3-4-5-4	**Silty Sand (SM):** fine sand, 12–20% npf, brown, wet.
15'	S-6	24/21	15 - 17	5-5-6-7	**Silty Sand (SM):** fine sand, 12–20% npf, brown, wet.
					19'
20'	S-7	24/21	20 - 22	5-7-8-9	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray-brown, wet.
25'	S-8	24/18	25 - 27	8-7-9-13	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray-brown, wet
30'	S-9	24/12	30 - 31.2	9-12-100/2"	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray-brown, wet
					End of Boring @ 31.2'

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler and casing.

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

CHG Geotechnical Engineering

Project Name: **Rockingham Substation**		Boring No. **B-5**
Project Location: **Salem, New Hampshire**		Sheet 1 of 1
Project Number: **2016**		Location: See Figure 2
Boring Contractor: **Soil X Corp**		Approx. Elev.

Groundwater Observations

Date	Time	Depth
9/4/20	Completion	9'

	Casing	Sampler	Core
Type	Auger	Split Spoon	
Size I.D.	4-¼"	1-3/8"	
Hammer Wt.	Automatic Hammer		
Hammer Fall			

Date Start: 9/4/20
Date Finish: 9/4/20
Driller: P. Goodale
Inspector: C. Gross
Rig Type: CME-75 ATV

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/12	0 - 2	8-11-13-10	**Fill: Silty Sand (SM):** m/f sand, 12-20% npf, brown, moist.
	S-2	24/15	2 - 4	9-10-10-8	**Fill: Silty Sand (SM):** m/f sand, 5-15% fine gravel, 12-20% npf, brown, moist. 5'
5'	S-3	24/15	5 - 7	3-5-4-5	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist
	S-4	24/18	7 - 9	8-9-9-11	**Sand (SP-SM):** fine sand, 5-12% npf, light brown, moist 9'
10'	S-5	24/21	10 - 12	3-4-5-4	**Silty Sand (SM):** fine sand, 12–20% npf, brown, wet.
15'	S-6	24/21	15 - 17	4-5-5-6	**Silty Sand (SM):** fine sand, 12–20% npf, brown, wet.
20'	S-7	24/18	20 - 22	4-5-5-4	**Silty Sand (SM):** fine sand, 12-20% npf, brown, wet. 24'
25'	S-8	24/21	25 - 27	7-8-8-13	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray, wet
30'	S-9	24/21	30 - 32	6-7-8-22	**Silty Sand (SM):** c/f sand, 5-12% fine gravel, 12-20% npf, gray, wet
					End of Boring @ 32'

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

CHG Geotechnical Engineering

Project Name: **Rockingham Substation**		Boring No. **B-6**
Project Location: **Salem, New Hampshire**		Sheet 1 of 1
Project Number: **2016**		Location: See Figure 2
Boring Contractor: **Soil X Corp**		Approx. Elev.

Groundwater Observations

Date	Time	Depth
9/4/20	Completion	8'

	Casing	Sampler	Core
Type	Auger	Split Spoon	
Size I.D.	4-¼"	1-3/8"	
Hammer Wt.	Automatic Hammer		
Hammer Fall			

Date Start: 9/4/20
Date Finish: 9/4/20
Driller: P. Goodale
Inspector: C. Gross
Rig Type: CME-75 ATV

Depth	No.	Pen./Rec. (inches)	Sample Depth (feet)	Blows/6"	Sample Description
	S-1	24/9	0 - 2	6-7-9-5	**Fill: Silty Sand (SM):** c/f sand, 5-15% m/f gravel, 12-20% npf, black, moist.
	S-2	24/12	2 - 4	13-21-17-17	**Fill: Silty Sand (SM):** m/f sand, 5-15% fine gravel, 12-20% npf, black & light brown, moist. 5'
5'	S-3	24/18	5 - 7	1-1-1-2	**Peat (PT):** fibrous, black and brown, wet
	S-4	24/18	7 - 9	1-2-10-13	8'
10'	S-5	24/18	10 - 12	6-7-6-2	**Silty Sand (SM):** m/f fine sand, <5% fine gravel, 12–20% npf, brown, wet. 11.5'
					Sandy Silt (ML): slightly plastic, 20–30% very fine sand, gray-brown, wet. 13.5'
15'	S-6	24/18	15 - 17	6-6-7-11	**Silty Sand (SM):** c/f sand, 15–25% npf, brown, wet. 19'
20'	S-7	24/21	20 - 22	5-6-7-9	**Silty Sand (SM):** fine sand, 15-25% npf, brown, wet. 24'
25'	S-8	24/15	25 - 27	5-7-7-13	**Gravelly Sand:** c/f sand, 10-15 fine gravel, 5-12% npf, gray, wet
30'					**Auger Refusal @ 29'** **End of Boring @ 29'**

Sample Types
S - split spoon
ST - shelby tube
AF - auger flight
RC - rock core
c/f means coarse to fine
m/f means medium to fine
npf means nonplastic fines

Notes:
1. Automatic hammer used for driving & split-spoon sampler

Granular Soils

N-Value	Density
<4	very loose
5-10	loose
11-30	medium
31-50	dense
>50	very dense

Cohesive Soils

N-Value	Consistency
<2	very soft
2-4	soft
5-8	medium
9-15	stiff
16-30	very stiff
>30	hard

INDEX TO DRAWINGS

1. TITLE SHEET
2. EXISTING CONDITIONS PLAN
3. OVERVIEW PLAN
4. SITE PLAN
5. SITE SECTION
6. GRADING PLAN
7. STORMWATER MANAGEMENT PLAN
8. CONSTRUCTION DETAILS
LANDSCAPE PLAN (BY OTHERS)

ABUTTERS

MAP/LOT #	NAME & ADDRESS	MAP/LOT #	NAME & ADDRESS
98/12502	DEMOULAS SUPER MARKETS, INC. 875 EAST STREET TEWKSBURY, MA 01876	116/11150	MAY DEPARTMENT STORES COMPANY PROPERTY TAX DEPARTMENT 7 WEST 7TH STREET CINCINNATI, OH 45202
98/12543	TUSCAN VILLAGE RESIDENTIAL HOLDINGS, LLC 150 PRESIDENTIAL WAY, SUITE 200 WOBURN, MA 01801	117/7885	STATE OF NEW HAMPSHIRE P.O. BOX 483 CONCORD, NH 03301
98/11094 116/7884 116/11167	ROCKSAL MALL LLC C/O SIMON PROPERTY GROUP P.O. BOX 6120 INDIANAPOLIS, IN 46207	117/7880	ROCKINGHAM 620, INC. C/O KIMCO REALTY CORPORATION 3333 NEW HYDE PARK ROAD #100 NEW HYDE PARK, NY 11042
107/11154 107/11153	SERITAGE SRC FINANCE LLC 3333 BEVERLY ROAD HOFFMAN ESTATES, IL 60179	99/12507	DILORENZO LFAYETTE LEDGEWOOD REAL ESTATE, LLC C/O ANTHONY DILORENZO, MANAGER 549 US HIGHWAY 1 BYPASS PORTSMOUTH, NH 03801
116/11152	JC PENNEY PROPERTIES INC. PROPERTY TAX OFFICE P.O. BOX 10001 DALLAS, TX 75301	151/12213	STATE OF NHDOT JOHN O'MORTON BUILDING ONE HAZEN DRIVE CONCORD, NH 03302

PERMITS & APPROVALS

TYPE	PERMIT NUMBER	APPROVED
NHDES ALTERATION OF TERRAIN	AOT-1463	7/26/2018

SALEM PLANNING BOARD

1) ON JUNE 12, 2018 THE SALEM PLANNING BOARD VOTED TO GRANT A CONDITIONAL USE PERMIT TO ALLOW AN ELECTRIC SUBSTATION ON MAP 99, LOT 12572, A USE NOT ALLOWED IN THE COMMERCIAL-INDUSTRIAL C DISTRICT.

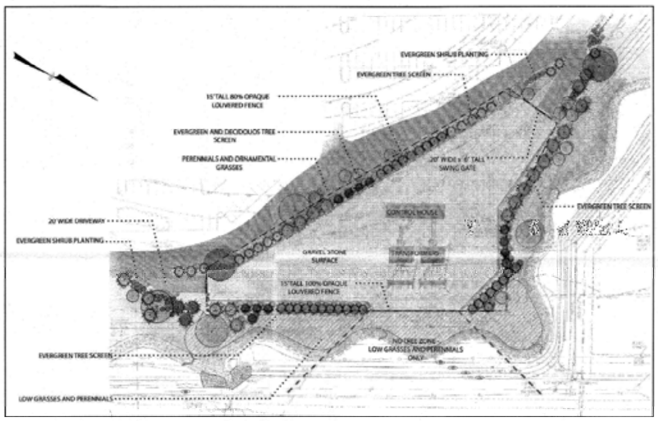
2) ON JULY 25, 2018 THE SALEM PLANNING BOARD VOTED TO APPROVE THIS SITE PLAN SUBJECT TO THE FOLLOWING CONDITIONS:

PRIOR TO BUILDING PERMIT:
1. NOTE CONDITIONAL USE PERMIT ON PLAN;
2. PAY FOR OUTSIDE INSPECTIONS PER DIRECTION OF ENGINEERING DIVISION;
3. SUBMIT STATE ALTERATION OF TERRAIN PERMIT;
4. SUBMIT RECORDED ACCESS EASEMENT;
5. ADD SHRUB PLANTINGS IN NO TREE ZONE;
6. ADD IRRIGATION SYSTEM;

PRIOR TO OCCUPANCY:
7. CONSTRUCT ALL SITE IMPROVEMENTS (INCLUDING SITE GRADING, UTILITIES, DRAINAGE, LANDSCAPING) IN ACCORDANCE WITH APPROVED PLAN;
8. PROVIDE CERTIFIED AS-BUILT PLAN;

OTHER:
9. ALL REPRESENTATIONS MADE BY APPLICANT OR AGENTS AND ALL NOTES ON PLANS ARE INCORPORATED AS PART OF APPROVAL

PROPOSED ELECTRIC SUBSTATION
SALEM PROPERTY MAP 99 LOT 12572
64 SOUTH BROADWAY
SALEM, NEW HAMPSHIRE



LOCATION MAP
(NOT TO SCALE)

Prepared for:

LIBERTY UTILITIES CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053

NO.	DESCRIPTION	BY	DATE
5	UPDATE OWNER	DRJ	3/12/20
4	REVISE LANDSCAPE PLAN	DRJ	2/24/20
3	ADD PLANNING BOARD AND AOT APPROVAL	DRJ	2/5/20
2	REVISED SHEET 2, 5-8	DRJ	6/29/18
1	REVISED SHEET 8	NID	6/6/18

REVISIONS

TITLE SHEET

PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 - LOT 12572
PROPERTY ADDRESS - 64 SOUTH BROADWAY

GPI Engineering Design Planning Construction Management
603.893.0720 GPINET.COM
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079

SCALE: NONE
DATE: MAY 25, 2018

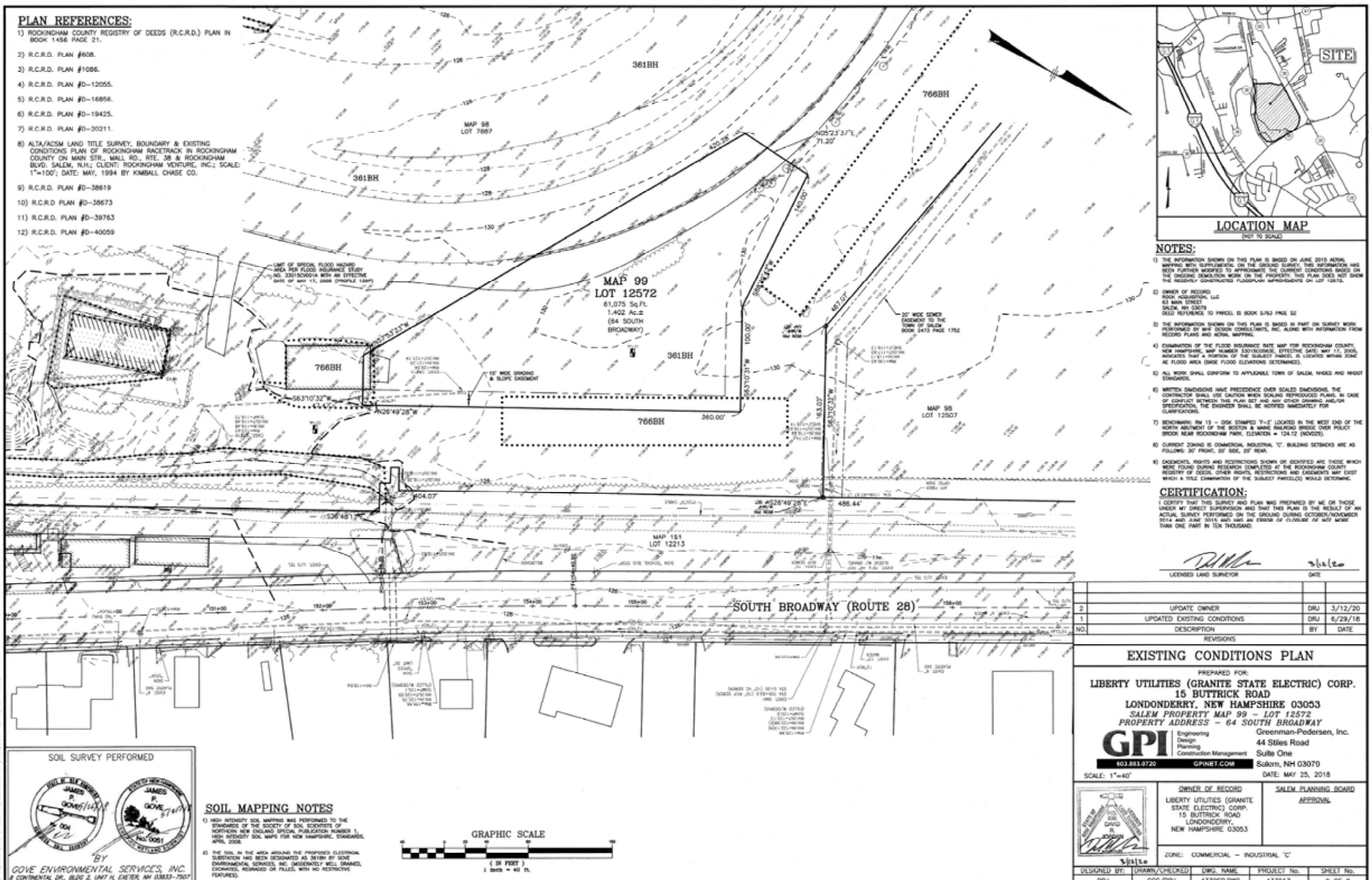
STATE OF NEW HAMPSHIRE DAVID R. JORDAN No. 7771
3/12/20

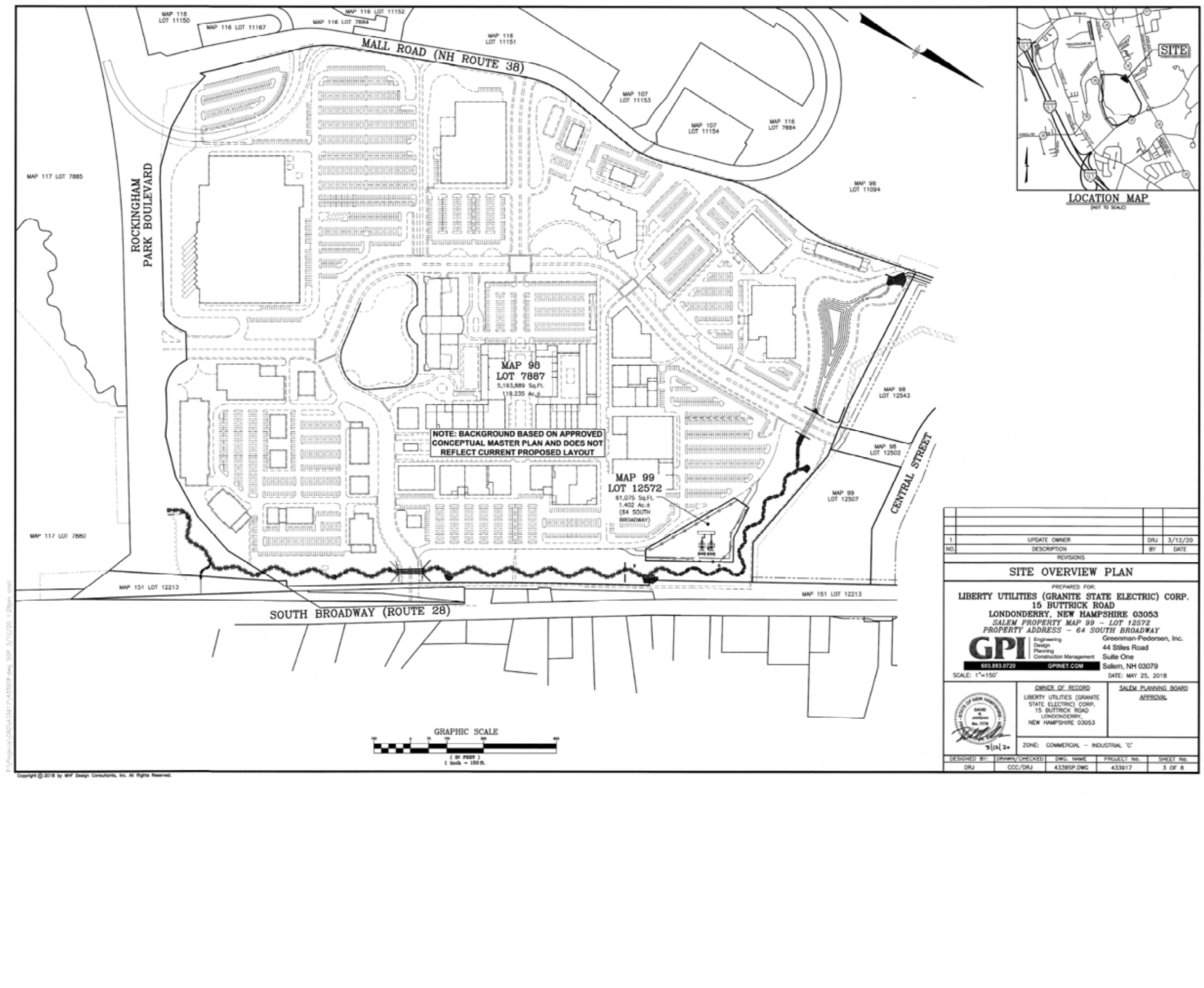
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053

SALEM PLANNING BOARD APPROVAL
Approved 7/24/18
Signed 4/20/20

ZONE: COMMERCIAL - INDUSTRIAL "C"

DESIGNED BY:	DRAWN/CHECKED	DWG. NAME	PROJECT No.	SHEET No.
DRJ	CCC/DRJ	4339SP.DWG	433917	1 OF 8


PLAN REFERENCES:
1) ROCKINGHAM COUNTY REGISTRY OF DEEDS (R.C.R.D.) PLAN IN BOOK 1456 PAGE 21.
2) R.C.R.D. PLAN #608.
3) R.C.R.D. PLAN #1086.
4) R.C.R.D. PLAN #D-12055.
5) R.C.R.D. PLAN #D-16856.
6) R.C.R.D. PLAN #D-19425.
7) R.C.R.D. PLAN #D-20211.
8) ALTA/ACSM LAND TITLE SURVEY, BOUNDARY & EXISTING CONDITIONS PLAN OF ROCKINGHAM RACETRACK IN ROCKINGHAM COUNTY ON MAIN STR., MALL RD., RTE. 38 & ROCKINGHAM BLVD. SALEM, N.H.; CLIENT: ROCKINGHAM VENTURE, INC.; SCALE: 1"=100'; DATE: MAY, 1994 BY KIMBALL CHASE CO.
9) R.C.R.D. PLAN #D-38619
10) R.C.R.D PLAN #D-38673
11) R.C.R.D. PLAN #D-39763
12) R.C.R.D. PLAN #D-40059
361BH
766BH
MAP 98
LOT 7667
MAP 99
LOT 12572
61,075 Sq.Ft.
1.402 Ac.±
(64 SOUTH BROADWAY)
MAP 98
LOT 12507
MAP 151
LOT 12213
SOUTH BROADWAY (ROUTE 28)
20' WIDE SEWER EASEMENT TO THE TOWN OF SALEM BOOK 2473 PAGE 1752
15' WIDE GRADING & SLOPE EASEMENT
360.00'
486.44'
404.07'
SITE
LOCATION MAP
(NOT TO SCALE)
NOTES:
1) THE INFORMATION SHOWN ON THIS PLAN IS BASED ON JUNE 2015 AERIAL MAPPING WITH SUPPLEMENTAL ON THE GROUND SURVEY. THIS INFORMATION HAS BEEN FURTHER MODIFIED TO APPROXIMATE THE CURRENT CONDITIONS BASED ON THE ONGOING DEMOLITION WORK ON THE PROPERTY. THIS PLAN DOES NOT SHOW THE RECENTLY CONSTRUCTED FLOODPLAIN IMPROVEMENTS ON LOT 12572.
2) OWNER OF RECORD: ROCK ACQUISITION, LLC 63 MAIN STREET SALEM, NH 03079 DEED REFERENCE TO PARCEL IS BOOK 5763 PAGE 52
3) THE INFORMATION SHOWN ON THIS PLAN IS BASED IN PART ON SURVEY WORK PERFORMED BY MHF DESIGN CONSULTANTS, INC. ALONG WITH INFORMATION FROM RECORD PLANS AND AERIAL MAPPING.
4) EXAMINATION OF THE FLOOD INSURANCE RATE MAP FOR ROCKINGHAM COUNTY, NEW HAMPSHIRE, MAP NUMBER 33015C0563E, EFFECTIVE DATE: MAY 17, 2005, INDICATES THAT A PORTION OF THE SUBJECT PARCEL IS LOCATED WITHIN ZONE AE FLOOD AREA (BASE FLOOD ELEVATIONS DETERMINED).
5) ALL WORK SHALL CONFORM TO APPLICABLE TOWN OF SALEM, NHDES AND NHDOT STANDARDS.
6) WRITTEN DIMENSIONS HAVE PRECEDENCE OVER SCALED DIMENSIONS. THE CONTRACTOR SHALL USE CAUTION WHEN SCALING REPRODUCED PLANS. IN CASE OF CONFLICT BETWEEN THIS PLAN SET AND ANY OTHER DRAWING AND/OR SPECIFICATION, THE ENGINEER SHALL BE NOTIFIED IMMEDIATELY FOR CLARIFICATIONS.
7) BENCHMARK: RM 15 - DISK STAMPED 'F-3' LOCATED IN THE WEST END OF THE NORTH ABUTMENT OF THE BOSTON & MAINE RAILROAD BRIDGE OVER POLICY BROOK NEAR ROCKINGHAM PARK. ELEVATION = 124.12 (NGVD29).
8) CURRENT ZONING IS COMMERCIAL INDUSTRIAL 'C'. BUILDING SETBACKS ARE AS FOLLOWS: 30' FRONT, 20' SIDE, 20' REAR.
9) EASEMENTS, RIGHTS AND RESTRICTIONS SHOWN OR IDENTIFIED ARE THOSE WHICH WERE FOUND DURING RESEARCH COMPLETED AT THE ROCKINGHAM COUNTY REGISTRY OF DEEDS. OTHER RIGHTS, RESTRICTIONS AND EASEMENTS MAY EXIST WHICH A TITLE EXAMINATION OF THE SUBJECT PARCEL(S) WOULD DETERMINE.
CERTIFICATION:
I CERTIFY THAT THIS SURVEY AND PLAN WAS PREPARED BY ME OR THOSE UNDER MY DIRECT SUPERVISION AND THAT THIS PLAN IS THE RESULT OF AN ACTUAL SURVEY PERFORMED ON THE GROUND DURING OCTOBER/NOVEMBER 2014 AND JUNE 2015 AND HAS AN ERROR OF CLOSURE OF NOT MORE THAN ONE PART IN TEN THOUSAND.
3/12/20
LICENSED LAND SURVEYOR
DATE
2 UPDATE OWNER DRJ 3/12/20
1 UPDATED EXISTING CONDITIONS DRJ 6/29/18
NO. DESCRIPTION BY DATE
REVISIONS
EXISTING CONDITIONS PLAN
PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 - LOT 12572
PROPERTY ADDRESS - 64 SOUTH BROADWAY
GPI
Engineering
Design
Planning
Construction Management
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079
603.893.0720
GPINET.COM
SCALE: 1"=40'
DATE: MAY 25, 2018
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. 15 BUTTRICK ROAD LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PLANNING BOARD APPROVAL
ZONE: COMMERCIAL - INDUSTRIAL 'C'
DESIGNED BY: DRJ
DRAWN/CHECKED: CCC/DRJ
DWG. NAME: 4339SP.DWG
PROJECT No.: 433917
SHEET No.: 2 OF 8
SOIL SURVEY PERFORMED
JAMES P. GOVE
No. 0051
BY
GOVE ENVIRONMENTAL SERVICES, INC.
8 CONTINENTAL DR., BLDG 2, UNIT H, EXETER, NH 03833-7507
SOIL MAPPING NOTES
1) HIGH INTENSITY SOIL MAPPING WAS PERFORMED TO THE STANDARDS OF THE SOCIETY OF SOIL SCIENTISTS OF NORTHERN NEW ENGLAND SPECIAL PUBLICATION NUMBER 1, HIGH INTENSITY SOIL MAPS FOR NEW HAMPSHIRE, STANDARDS, APRIL 2009.
2) THE SOIL IN THE AREA AROUND THE PROPOSED ELECTRICAL SUBSTATION HAS BEEN DESIGNATED AS 361BH BY GOVE ENVIRONMENTAL SERVICES, INC. (MODERATELY WELL DRAINED, EXCAVATED, REGRADED OR FILLED, WITH NO RESTRICTIVE FEATURES).
GRAPHIC SCALE
(IN FEET)
1 inch = 40 ft.


MALL ROAD (NH ROUTE 38)
ROCKINGHAM PARK BOULEVARD
SOUTH BROADWAY (ROUTE 28)
CENTRAL STREET
MAP 117 LOT 7885
MAP 117 LOT 7880
MAP 116 LOT 11150
MAP 116 LOT 11167
MAP 116 LOT 11152
MAP 116 LOT 7884
MAP 116 LOT 11151
MAP 107 LOT 11153
MAP 107 LOT 11154
MAP 116 LOT 7884
MAP 98 LOT 11094
MAP 98 LOT 12543
MAP 98 LOT 12502
MAP 99 LOT 12507
MAP 151 LOT 12213
MAP 98
LOT 7887
5,193,889 Sq.Ft.
119.235 Ac.±
MAP 99
LOT 12572
61,075 Sq.Ft.
1.402 Ac.±
(64 SOUTH BROADWAY)
NOTE: BACKGROUND BASED ON APPROVED CONCEPTUAL MASTER PLAN AND DOES NOT REFLECT CURRENT PROPOSED LAYOUT
SITE
LOCATION MAP
(NOT TO SCALE)
GRAPHIC SCALE
(IN FEET)
1 inch = 150 ft.
1 | UPDATE OWNER | DRJ | 3/12/20
NO. | DESCRIPTION | BY | DATE
REVISIONS
SITE OVERVIEW PLAN
PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY
GPI
Engineering
Design
Planning
Construction Management
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079
603.893.0720
GPINET.COM
SCALE: 1"=150'
DATE: MAY 25, 2018
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053
SALEM PLANNING BOARD APPROVAL
ZONE: COMMERCIAL – INDUSTRIAL 'C'
DESIGNED BY: | DRAWN/CHECKED | DWG. NAME | PROJECT No. | SHEET No.
DRJ | CCC/DRJ | 4339SP.DWG | 433917 | 3 OF 8
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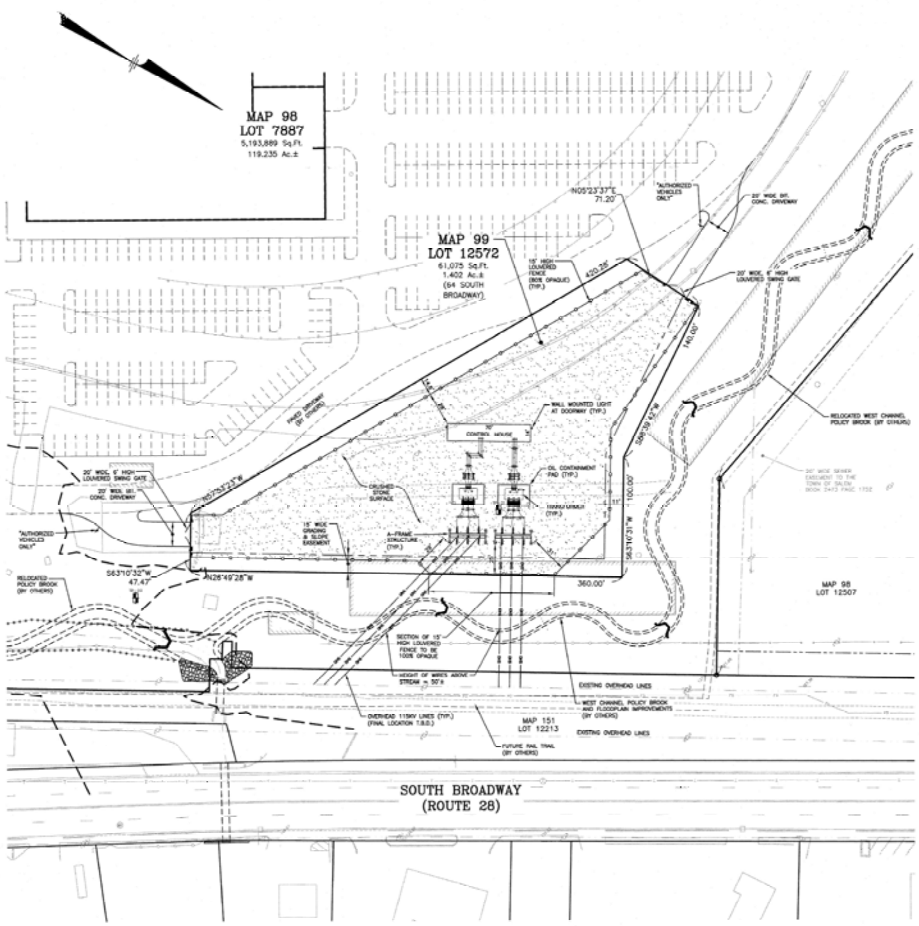


LOCATION MAP
(NOT TO SCALE)

NOTES:

1) THE PURPOSE OF THIS PLAN IS TO SHOW A PROPOSED LAYOUT FOR AN ELECTRIC SUBSTATION ON MAP 99 LOT 12572 UNDER THE PROVISIONS OF THE LARGE SCALE REDEVELOPMENT ORDINANCE, SECTION 490-710.
2) THE INFORMATION SHOWN ON THIS PLAN IS BASED IN PART ON SURVEY WORK PERFORMED BY MHF DESIGN CONSULTANTS, INC. ALONG WITH INFORMATION FROM RECORD PLANS AND AERIAL MAPPING.
3) ALL WORK SHALL CONFORM TO APPLICABLE TOWN OF SALEM, NHDES AND NHDOT STANDARDS.
4) WRITTEN DIMENSIONS HAVE PRECEDENCE OVER SCALED DIMENSIONS. THE CONTRACTOR SHALL USE CAUTION WHEN SCALING REPRODUCED PLANS. IN CASE OF CONFLICT BETWEEN THIS PLAN SET AND ANY OTHER DRAWING AND/OR SPECIFICATION, THE ENGINEER SHALL BE NOTIFIED IMMEDIATELY FOR CLARIFICATIONS.
5) PRIOR TO CONSTRUCTION THE CONTRACTOR SHALL CONFIRM WITH THE ENGINEER THAT HE HAS THE MOST RECENT SET OF PLANS. SITE WORK SHALL BE CONSTRUCTED FROM A COMPLETE SET OF PLANS. NOT ALL FEATURES ARE DETAILED ON EVERY SHEET. THE ENGINEER IS TO BE NOTIFIED OF ANY CONFLICT WITHIN THIS PLAN SET.
6) CONTRACTOR TO CONFIRM BENCHMARKS PRIOR TO COMMENCEMENT OF WORK.
7) THE CONTRACTOR SHALL BE RESPONSIBLE FOR THE VERIFYING AND DETERMINING THE LOCATION, SIZE, AND ELEVATION OF ALL EXISTING UTILITIES PRIOR TO THE START OF ANY CONSTRUCTION. THE ENGINEER SHALL BE NOTIFIED IN WRITING OF ANY UTILITIES FOUND INTERFERING WITH THE PROPOSED CONSTRUCTION AND APPROPRIATE REMEDIAL ACTION SHALL BE AGREED TO BY THE ENGINEER BEFORE PROCEEDING WITH THE WORK. THE CONTRACTOR SHALL BE RESPONSIBLE FOR CONTACTING "DIG SAFE" (888-344-7233) AT LEAST 72 HOURS PRIOR TO ANY DIGGING.

NO.	DESCRIPTION	BY	DATE
1	UPDATE OWNER	DRJ	3/12/20

REVISIONS

SITE PLAN

PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY

GPI Engineering, Design, Planning, Construction Management
603.893.0720 GPINET.COM
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079

SCALE: 1"=40'
DATE: MAY 25, 2018

STATE OF NEW HAMPSHIRE DAVID R. JORDAN No. 7778
3/12/20

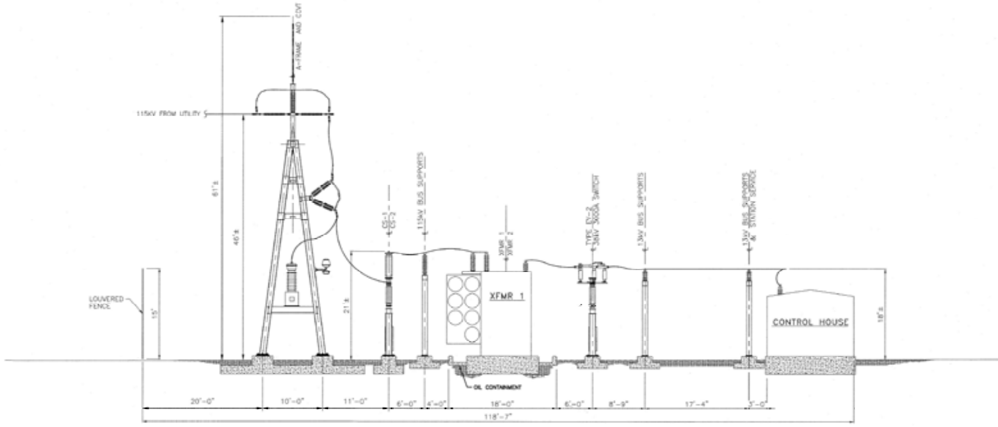
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053

SALEM PLANNING BOARD APPROVAL

ZONE: COMMERCIAL – INDUSTRIAL 'C'

DESIGNED BY:	DRAWN/CHECKED	DWG. NAME	PROJECT No.	SHEET No.
DRJ	CCC/DRJ	4339SP.DWG	433917	4 OF 8

811 DigSafe



SECTION A
SIDE ELEVATION
SK-17128-XX

NO.	DESCRIPTION	BY	DATE
2	UPDATE OWNER	DRJ	3/12/20
1	UPDATE DIMENSIONS	DRJ	6/29/18

REVISIONS

SITE SECTION

PREPARED FOR:

**LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053**

SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY

GPI Engineering Design Planning Construction Management
603.893.0720 GPINET.COM

Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079

NOT TO SCALE

DATE: MARCH 25, 2018

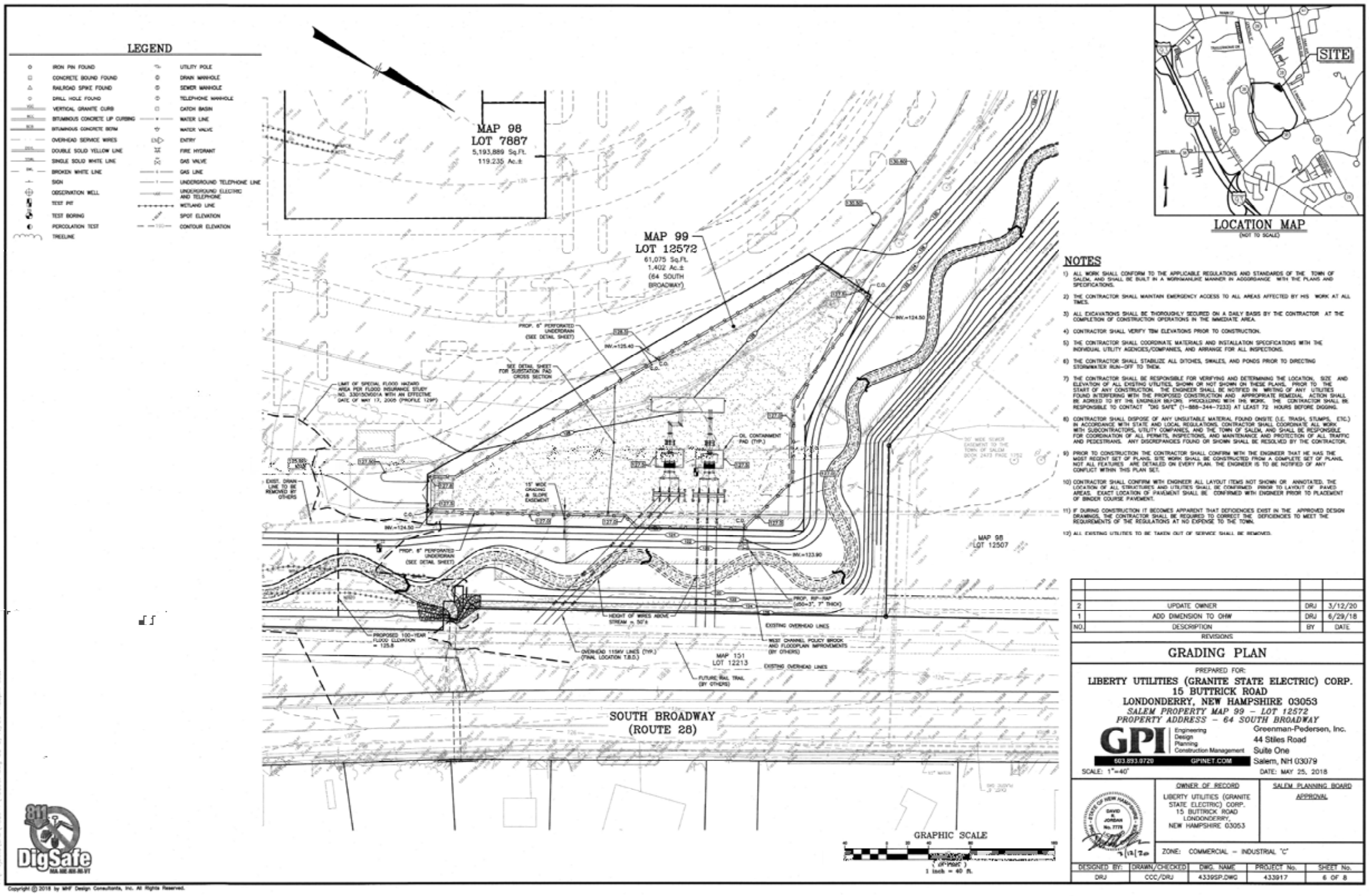
STATE OF NEW HAMPSHIRE DAVID R. JORDAN No. 7778
3/12/20

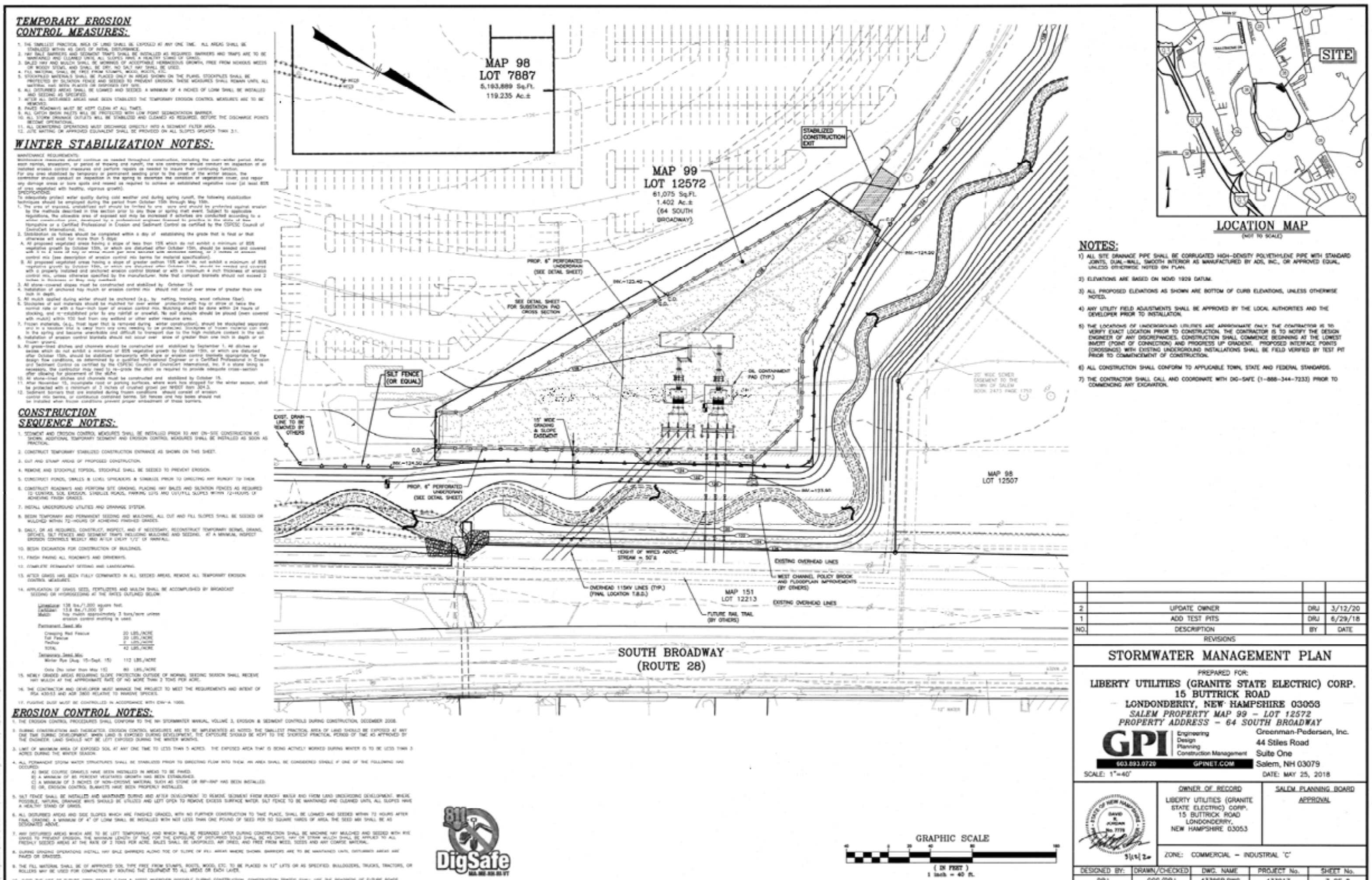
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053

SALEM PLANNING BOARD APPROVAL

ZONE: COMMERCIAL – INDUSTRIAL "C"

DESIGNED BY:	DRAWN/CHECKED	DWG. NAME	PROJECT No.	SHEET No.
DRJ	CCC/DRJ	4339ELEV.DWG	433917	5 OF 8


LEGEND
MAP 98
LOT 7887
5,193,889 Sq.Ft.
119.235 Ac.±
MAP 99
LOT 12572
61,075 Sq.Ft.
1.402 Ac.±
(64 SOUTH BROADWAY)
MAP 98
LOT 12507
MAP 151
LOT 12213
SOUTH BROADWAY
(ROUTE 28)
LOCATION MAP
(NOT TO SCALE)
SITE
NOTES
1) ALL WORK SHALL CONFORM TO THE APPLICABLE REGULATIONS AND STANDARDS OF THE TOWN OF SALEM, AND SHALL BE BUILT IN A WORKMANLIKE MANNER IN ACCORDANCE WITH THE PLANS AND SPECIFICATIONS.
2) THE CONTRACTOR SHALL MAINTAIN EMERGENCY ACCESS TO ALL AREAS AFFECTED BY HIS WORK AT ALL TIMES.
3) ALL EXCAVATIONS SHALL BE THOROUGHLY SECURED ON A DAILY BASIS BY THE CONTRACTOR AT THE COMPLETION OF CONSTRUCTION OPERATIONS IN THE IMMEDIATE AREA.
4) CONTRACTOR SHALL VERIFY TBM ELEVATIONS PRIOR TO CONSTRUCTION.
5) THE CONTRACTOR SHALL COORDINATE MATERIALS AND INSTALLATION SPECIFICATIONS WITH THE INDIVIDUAL UTILITY AGENCIES/COMPANIES, AND ARRANGE FOR ALL INSPECTIONS.
6) THE CONTRACTOR SHALL STABILIZE ALL DITCHES, SWALES, AND PONDS PRIOR TO DIRECTING STORMWATER RUN-OFF TO THEM.
7) THE CONTRACTOR SHALL BE RESPONSIBLE FOR VERIFYING AND DETERMINING THE LOCATION, SIZE AND ELEVATION OF ALL EXISTING UTILITIES, SHOWN OR NOT SHOWN ON THESE PLANS, PRIOR TO THE START OF ANY CONSTRUCTION. THE ENGINEER SHALL BE NOTIFIED IN WRITING OF ANY UTILITIES FOUND INTERFERING WITH THE PROPOSED CONSTRUCTION AND APPROPRIATE REMEDIAL ACTION SHALL BE AGREED TO BY THE ENGINEER BEFORE PROCEEDING WITH THE WORK. THE CONTRACTOR SHALL BE RESPONSIBLE TO CONTACT "DIG SAFE" (1-888-344-7233) AT LEAST 72 HOURS BEFORE DIGGING.
8) CONTRACTOR SHALL DISPOSE OF ANY UNSUITABLE MATERIAL FOUND ONSITE (I.E. TRASH, STUMPS, ETC.) IN ACCORDANCE WITH STATE AND LOCAL REGULATIONS. CONTRACTOR SHALL COORDINATE ALL WORK WITH SUBCONTRACTORS, UTILITY COMPANIES, AND THE TOWN OF SALEM, AND SHALL BE RESPONSIBLE FOR COORDINATION OF ALL PERMITS, INSPECTIONS, AND MAINTENANCE AND PROTECTION OF ALL TRAFFIC AND PEDESTRIANS. ANY DISCREPANCIES FOUND OR SHOWN SHALL BE RESOLVED BY THE CONTRACTOR.
9) PRIOR TO CONSTRUCTION THE CONTRACTOR SHALL CONFIRM WITH THE ENGINEER THAT HE HAS THE MOST RECENT SET OF PLANS. SITE WORK SHALL BE CONSTRUCTED FROM A COMPLETE SET OF PLANS. NOT ALL FEATURES ARE DETAILED ON EVERY PLAN. THE ENGINEER IS TO BE NOTIFIED OF ANY CONFLICT WITHIN THIS PLAN SET.
10) CONTRACTOR SHALL CONFIRM WITH ENGINEER ALL LAYOUT ITEMS NOT SHOWN OR ANNOTATED. THE LOCATION OF ALL STRUCTURES AND UTILITIES SHALL BE CONFIRMED PRIOR TO LAYOUT OF PAVED AREAS. EXACT LOCATION OF PAVEMENT SHALL BE CONFIRMED WITH ENGINEER PRIOR TO PLACEMENT OF BINDER COURSE PAVEMENT.
11) IF DURING CONSTRUCTION IT BECOMES APPARENT THAT DEFICIENCIES EXIST IN THE APPROVED DESIGN DRAWINGS, THE CONTRACTOR SHALL BE REQUIRED TO CORRECT THE DEFICIENCIES TO MEET THE REQUIREMENTS OF THE REGULATIONS AT NO EXPENSE TO THE TOWN.
12) ALL EXISTING UTILITIES TO BE TAKEN OUT OF SERVICE SHALL BE REMOVED.
2 UPDATE OWNER DRJ 3/12/20
1 ADD DIMENSION TO OHW DRJ 6/29/18
NO. DESCRIPTION BY DATE
REVISIONS
GRADING PLAN
PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY
GPI
Engineering
Design
Planning
Construction Management
603.893.0720
GPINET.COM
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079
SCALE: 1"=40'
DATE: MAY 25, 2018
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053
SALEM PLANNING BOARD APPROVAL
ZONE: COMMERCIAL – INDUSTRIAL "C"
DESIGNED BY: DRJ
DRAWN/CHECKED: CCC/DRJ
DWG. NAME: 4339SP.DWG
PROJECT No. 433917
SHEET No. 6 OF 8
GRAPHIC SCALE
1 inch = 40 ft.
811
DigSafe



NOTES:

1) ALL SITE DRAINAGE PIPE SHALL BE CORRUGATED HIGH-DENSITY POLYETHYLENE PIPE WITH STANDARD JOINTS, DUAL-WALL, SMOOTH INTERIOR AS MANUFACTURED BY ADS, INC., OR APPROVED EQUAL, UNLESS OTHERWISE NOTED ON PLAN.

2) ELEVATIONS ARE BASED ON NGVD 1929 DATUM.

3) ALL PROPOSED ELEVATIONS AS SHOWN ARE BOTTOM OF CURB ELEVATIONS, UNLESS OTHERWISE NOTED.

4) ANY UTILITY FIELD ADJUSTMENTS SHALL BE APPROVED BY THE LOCAL AUTHORITIES AND THE DEVELOPER PRIOR TO INSTALLATION.

5) THE LOCATIONS OF UNDERGROUND UTILITIES ARE APPROXIMATE ONLY. THE CONTRACTOR IS TO VERIFY EXACT LOCATION PRIOR TO CONSTRUCTION. THE CONTRACTOR IS TO NOTIFY THE DESIGN ENGINEER OF ANY DISCREPANCIES. CONSTRUCTION SHALL COMMENCE BEGINNING AT THE LOWEST INVERT (POINT OF CONNECTION) AND PROGRESS UP GRADIENT. PROPOSED INTERFACE POINTS (CROSSINGS) WITH EXISTING UNDERGROUND INSTALLATIONS SHALL BE FIELD VERIFIED BY TEST PIT PRIOR TO COMMENCEMENT OF CONSTRUCTION.

6) ALL CONSTRUCTION SHALL CONFORM TO APPLICABLE TOWN, STATE AND FEDERAL STANDARDS.

7) THE CONTRACTOR SHALL CALL AND COORDINATE WITH DIG-SAFE (1-888-344-7233) PRIOR TO COMMENCING ANY EXCAVATION.

NO.	DESCRIPTION	BY	DATE
2	UPDATE OWNER	DRJ	3/12/20
1	ADD TEST PITS	DRJ	6/29/18

REVISIONS

STORMWATER MANAGEMENT PLAN

PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY

GPI Engineering Design Planning Construction Management
603.893.0720 GPINET.COM
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079

SCALE: 1"=40'
DATE: MAY 25, 2018

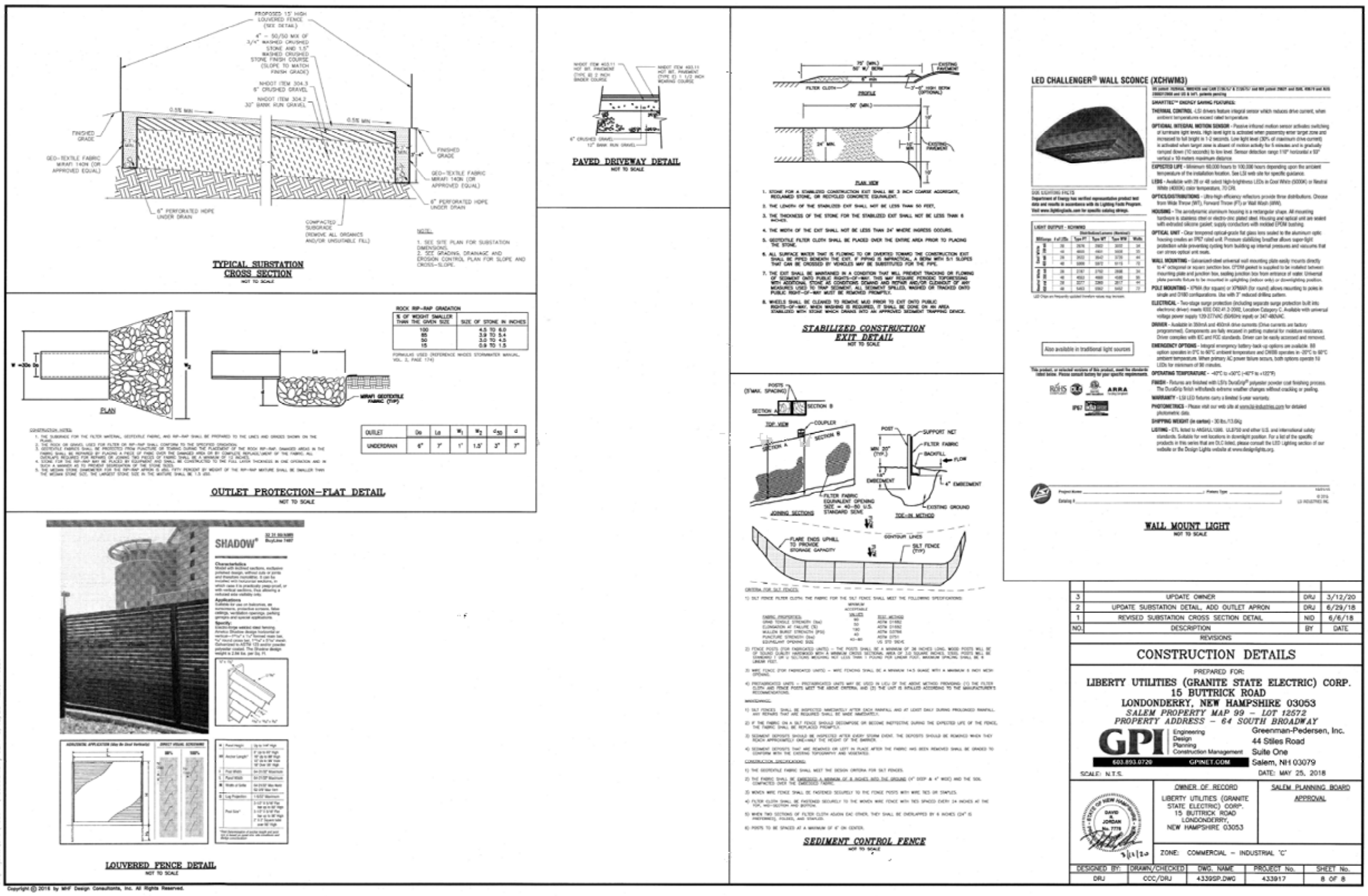
STATE OF NEW HAMPSHIRE DAVID R. JORDAN No. 7776
3/12/20

OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053

SALEM PLANNING BOARD APPROVAL

ZONE: COMMERCIAL – INDUSTRIAL "C"

DESIGNED BY:	DRAWN/CHECKED	DWG. NAME	PROJECT No.	SHEET No.
DRJ	CCC/DRJ	4339SP.DWG	433917	7 OF 8


TYPICAL SUBSTATION CROSS SECTION
NOT TO SCALE
PAVED DRIVEWAY DETAIL
NOT TO SCALE
STABILIZED CONSTRUCTION EXIT DETAIL
NOT TO SCALE
LED CHALLENGER® WALL SCONCE (XCHWM3)
WALL MOUNT LIGHT
NOT TO SCALE
OUTLET PROTECTION–FLAT DETAIL
NOT TO SCALE
SHADOW®
LOUVERED FENCE DETAIL
NOT TO SCALE
SEDIMENT CONTROL FENCE
NOT TO SCALE
3 UPDATE OWNER DRJ 3/12/20
2 UPDATE SUBSTATION DETAIL, ADD OUTLET APRON DRJ 6/29/18
1 REVISED SUBSTATION CROSS SECTION DETAIL NID 6/6/18
NO. DESCRIPTION BY DATE
REVISIONS
CONSTRUCTION DETAILS
PREPARED FOR:
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY
GPI
Engineering
Design
Planning
Construction Management
GPINET.COM
Greenman-Pedersen, Inc.
44 Stiles Road
Suite One
Salem, NH 03079
SCALE: N.T.S.
DATE: MAY 25, 2018
OWNER OF RECORD
LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY,
NEW HAMPSHIRE 03053
SALEM PLANNING BOARD APPROVAL
ZONE: COMMERCIAL – INDUSTRIAL 'C'
DESIGNED BY: DRJ
DRAWN/CHECKED: CCC/DRJ
DWG. NAME: 4339SP.DWG
PROJECT No.: 433917
SHEET No.: 8 OF 8
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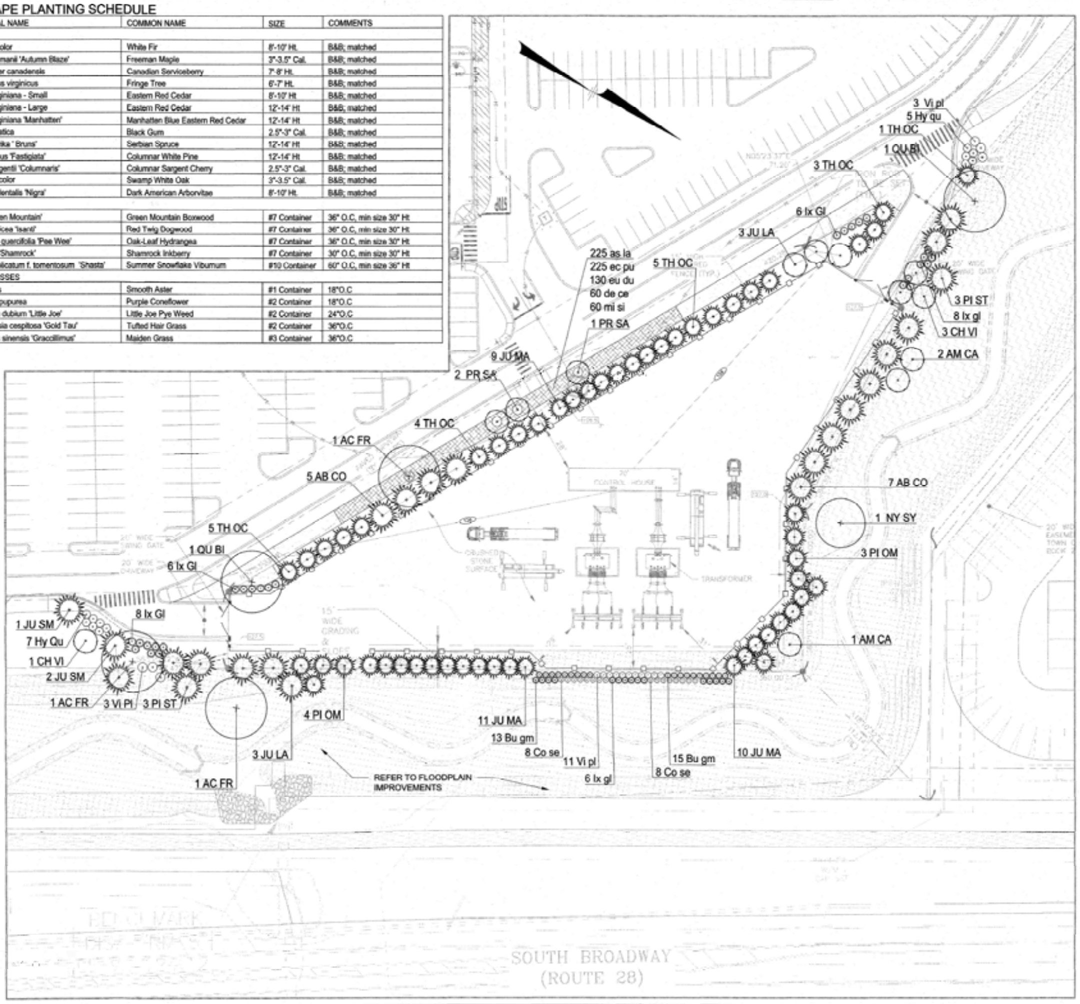
GENERAL LANDSCAPE PLANTING SCHEDULE

KEY	QNTY	BOTANICAL NAME	COMMON NAME	SIZE	COMMENTS
TREES					
AB CO	12	Abies concolor	White Fir	8'-10' Ht.	B&B; matched
AC FR	3	Acer x freemanii 'Autumn Blaze'	Freeman Maple	3"-3.5" Cal.	B&B; matched
AM CA	3	Amelanchier canadensis	Canadian Serviceberry	7'-8' Ht.	B&B; matched
CH VI	4	Chionanthus virginicus	Fringe Tree	6'-7' Ht.	B&B; matched
JU SM	3	Juniper virginiana - Small	Eastern Red Cedar	8'-10' Ht	B&B; matched
JU LA	6	Juniper virginiana - Large	Eastern Red Cedar	12'-14' Ht	B&B; matched
JU MA	30	Juniper virginiana 'Manhatten'	Manhatten Blue Eastern Red Cedar	12'-14' Ht	B&B; matched
NY SY	1	Nyssa sylvatica	Black Gum	2.5"-3" Cal.	B&B; matched
PI OM	7	Picea omorika ' Bruns'	Serbian Spruce	12'-14' Ht	B&B; matched
PI ST	6	Pinus strobus 'Fastigiata'	Columnar White Pine	12'-14' Ht	B&B; matched
PR SA	3	Prunus sargentii 'Columnaris'	Columnar Sargent Cherry	2.5"-3" Cal.	B&B; matched
QU BI	2	Quercus bicolor	Swamp White Oak	3"-3.5" Cal.	B&B; matched
TH OC	18	Thuja occidentalis 'Nigra'	Dark American Arborvitae	8'-10' Ht.	B&B; matched
SHRUBS					
Bu Gm	28	Buxus 'Green Mountain'	Green Mountain Boxwood	#7 Container	36" O.C, min size 30" Ht
Co Se	16	Cornus sericea 'Isanti'	Red Twig Dogwood	#7 Container	36" O.C, min size 30" Ht
Hy qu	12	Hydrangea quercifolia 'Pee Wee'	Oak-Leaf Hydrangea	#7 Container	36" O.C, min size 30" Ht
Ix gl	34	Ilex glabra 'Shamrock'	Shamrock Inkberry	#7 Container	30" O.C, min size 30" Ht
Vi pl	17	Viburnum plicatum f. tomentosum 'Shasta'	Summer Snowflake Viburnum	#10 Container	60" O.C, min size 36" Ht
PERENNIALS/ORNAMENTAL GRASSES					
as la	225	Aster laevis	Smooth Aster	#1 Container	18"O.C
ec pu	225	Echinacea pupurea	Purple Coneflower	#2 Container	18"O.C
eu du	1130	Eutrochium dubium 'Little Joe'	Little Joe Pye Weed	#2 Container	24"O.C
de ce	60	Deschampsia cespitosa 'Gold Tau'	Tufted Hair Grass	#2 Container	36"O.C
mi si	60	Miscanthus sinensis 'Graccillimus'	Maiden Grass	#3 Container	36"O.C



LOCATION MAP

GRAPHIC SCALE

(IN FEET)
1 inch = 30 ft.

LEGEND

- SEEDED LAWN
- PERENNIALS / ORNAMENTAL GRASSES
- LIMIT OF WORK LINE
- EXISTING TREE TO REMAIN
- DECIDUOUS TREE
- CONIFEROUS TREE
- ORNAMENTAL TREE
- SHRUBS

GENERAL NOTES

1. FOR PLANTING SCHEDULE SEE LANDSCAPE PLAN L-1.
2. ROADWAY AND UTILITIES LAYOUT ARE SHOWN FOR REFERENCE ONLY. REFER TO THE ROADWAY ENGINEERING DRAWINGS.
3. FOR ADJACENT PROPOSED DEVELOPMENTS REFER TO THE 'TUSCAN VILLAGE MASTER PLAN' AND RELEVANT DEVELOPMENT PLANS.
4. IRRIGATION FOR THE PLANTINGS AROUND THE SUBSTATION PERIMETER WILL BE PROVIDED BY THE TUSCAN VILLAGE IRRIGATION SYSTEM.

NO.	DESCRIPTION	BY	DATE
1	PLANTING REVISION	OS	2/24/2020

REVISIONS

LANDSCAPE PLAN L-2

PREPARED FOR:

LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP.
15 BUTTRICK ROAD
LONDONDERRY, NEW HAMPSHIRE 03053
SALEM PROPERTY MAP 99 – LOT 12572
PROPERTY ADDRESS – 64 SOUTH BROADWAY

HALVORSON DESIGN PARTNERSHIP
25 Kingston St, Boston MA 02111
P. 617.536.0380 F.617.536.0626

MHF Design Consultants, Inc.

SCALE: 1"=30'

DATE: MAY 24, 2018

OWNER OF RECORD
ROCK ACQUISITION, LLC
63 MAIN STREET
SALEM, NEW HAMPSHIRE 03079
BOOK 5763 PAGE 52

SALEM PLANNING BOARD APPROVAL

ZONE: COMMERCIAL – INDUSTRIAL 'C'

DESIGNED BY:	DRAWN/CHECKED	DWG. NAME	PROJECT No.	SHEET No.
MAL	BU/MAL		433917	2 OF 3

April 2, 2021

TO: Ross Moldoff, Salem Planning Director

RE: Liberty Utilities Rockingham Substation Fence

Dear Mr. Moldoff,

As a follow up to our discussion on Monday, March 29th, 2021, I am submitting this letter to request approval from both you and the members of the Planning Board to use a different type of screening around our Rockingham Substation than originally proposed. Our current option is the Shadow Fence (see attachment A-1). It has been recently brought to our attention that this type of fence needs to have an independent engineering review to determine proper below grade support and may require a foundation wall with a poured footing. Unfortunately, this was not known to Liberty when this fence was proposed to use three years ago, as we believed this fence could be installed similar to a 'traditional' (post holes backfilled with concrete) fence installation. To complete the task of an engineering review; procurement; and installation of fence, Liberty is estimating a timeframe of one year. Unfortunately, postponing the construction for one year is not feasible as the substation needs to be completed this year so that Liberty can continue to provide safe, reliable electric service to the Town of Salem.

Liberty would like to propose the use of pre-cast concrete wall with a stone finish. Please see attachments A-2 (preferred style, color of stone to be darker than pictured) and A-3 as examples. The support for these walls are similar to a traditional fence and can be procured and installed in accordance with our current construction schedule. Liberty intends to maintain the 15 foot height of the wall and utilize gates similar to the Shadow Fence thus limiting the view inside the substation. One change Liberty is proposing, is to increase the height of the gates from 6 feet to 7 feet as this is more in line with industry standards.

Thank you for your time and consideration of this request. If you have any questions, please contact me at 603-327-9367 or at Anthony.strabone@libertyutilities.com.

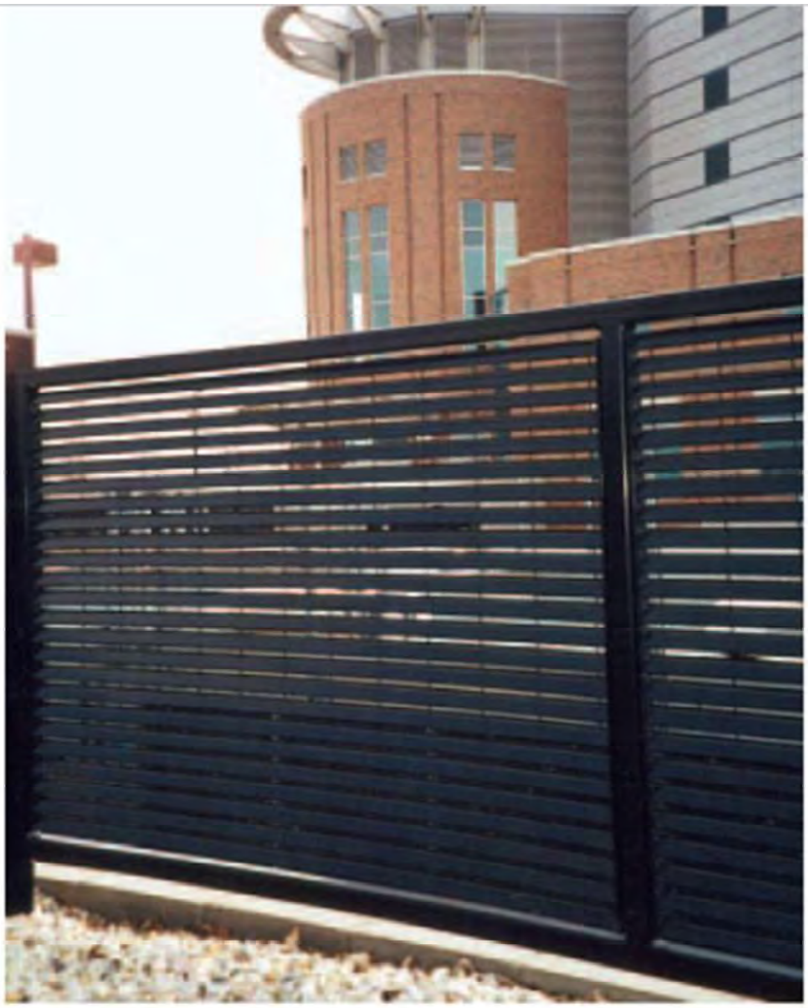
Sincerely,

Anthony Strabone

Anthony Strabone

Liberty

Attachment A-1: Shadow Fence



Attachment A-2 (preferred) Concrete Wall; Stone finish with smooth posts

Attachment A-3: Concrete Wall; Stone finish with matching posts/columns

Town of Salem, New Hampshire
Community Development Department
Planning Division
33 Geremonty Drive, Salem, New Hampshire 03079
(603) 890-2080 - Fax (603) 898-1223

Ross A. Moldoff, AICP
Planning Director

April 15, 2021

Anthony Strabone
Liberty Utilities
9 Lowell Road
Salem, NH 03079

RE: Map 99, Lot 12572
64 S. Broadway – Substation Fence

Dear Anthony:

At their meeting on April 13, 2021, the Planning Board granted your request to use a different type of fence than originally proposed around the Liberty Utilities Tuscan Substation at 64 South Broadway, per your letter dated April 2, 2021.

Please contact me if you have any questions.

Sincerely,

Ross A. Moldoff

Ross A. Moldoff
Planning Director

app.ltr.2021/S.Broadway-064/LibertyUtilities/substation fence

tjd&a | Terrence J. DeWan & Associates
Landscape Architects & Planners

June 11, 2018

TO: Ross Moldoff, Salem Planning Director
FR: Terry DeWan / TJD&A

RE: LIBERTY UTILITIES SUBSTATION PEER REVIEW
TUSCAN VILLAGE

The following comments are based upon information received by the Applicant, our knowledge of the site, review of Google Maps StreetView, and other data sources. The Applicant information includes:

- Proposed Electrical Substation Plan Set, prepared by MHF Design Consultants, dated May 25, 2018 (Sheets 1 through 8).
- STV Substation Site Plan, prepared by Halvorson Design Partnership, dated 5.24.18.
- Email Correspondence from David R. Jordan, MHF Design, dated June 7, 2018.

GENERAL

Key. The Illustrative Site Landscape Plan should have a Key that identifies the various elements on the Plan.

Scale. The various landscape plans should include a scale to help understand and check plant spacing.

Context. The substation is one component of the much larger plan for Tuscan Village. It would be very informative if the Landscape Plans showed more of the surrounding context, i.e., future roadways and walkways, future Rail Trail, proposed plantings, adjacent utility lines, etc.

Existing Vegetation. There is a significant line of vegetation that now separates the Tuscan Village site from Route 28. There is no indication as to whether any of these trees will be preserved as part of the construction of the substation.

Adjacent Parking Lot (not part of this application). While not part of this review, the Planning Board should pay special attention to the landscape treatment of the parking lot between the buildings on the east side of Market Place and the floodplain mitigation stream. Without a substantial amount of buffer plantings, this 645 car parking area (as seen from Route 28) will be a highly visible part of Tuscan Village.

SITE PLAN / FOOTPRINT

The current Site Plan for the substation includes a substantial amount of crushed stone surfacing around the electrical components and control house. The Tuscan Village Masterplan, dated 5.30.18, indicates that the substation has the potential to expand into this additional space. However, the current application, dated 5.25.18, does not indicate any potential expansion. In the 6.7.18 correspondence, David Jordan states 'There will be no future expansion…. The area inside the fence is needed as maneuvering space for large tractor-trailers in the event transformer replacement is necessary and for the large utility trucks will lifts to access the overhead lines." The Planning Board should confirm that this is the current thinking regarding future expansion within the substation fencing.

VEGETATIVE SCREENING

The No Tree Zone facing Route 28 is to prohibit trees that could reach the safety zone around the electrical conductors. This is standard procedure in the design of utility lines and substations. However, there does not seem to be a reason why non-capable shrub species (i.e., would achieve a height of less than 15') should not be planted in this area. There are many native shrubs that should be considered for this location to maintain the continuity of the landscape screening. While it appears that shrubs in this location would be outside of the Liberty Utilities property, there are several other locations where this occurs.

In his June 6, 2018 memo, David Jordan addresses this issue by stating: "This area was kept clear of vegetation other than low grasses and perennials at the request of Liberty for the purpose of being able to access and maintain their overhead lines."

PLANTINGS

The Landscape Plan calls for low shrubs (Oak-leaf Hydrangea and Shamrock Inkberry) immediately adjacent to the southerly access gate. If this will be used during the winter months, the plantings should be moved further back from the edge of the access drive to account for snow storage that could harm the plantings.

The Manhattan Blue Juniper achieves a width of 5 to 10 feet. The Site Plan indicates that they will be spaced approximately 15' apart. If the intent is to provide a solid screen, the junipers should be planted closer together, or another tree selected that achieves a greater width at maturity.

The Manhattan Junipers adjacent to the southerly edge of the No Tree Zone appears to overlap with the possible location of the 115 kV conductors, as shown on Sheet 7 in the MHF Plan Set, which notes that the final location to be determined. This location should be verified and adjustments made to the planting plan if necessary.

Quantities should be added to the Planting Schedule.

The Common Name for Amelanchier should be changed on the Planting Schedule.

LOUVERED FENCE

The substation will be screened on most sides by a 15' tall louvered fence that provides 80% direct visual screening. Visit the company's website at: https://www.ametco.com/panel-types/shadow-80/ for illustration and photograph of recent installations.

In most instances this should provide an effective way to screen the lower electrical components from view, especially when used in combination with the proposed plantings. Where trees are not allowed (i.e., the No Tree Zone facing Route 28), the fencing will be 100% opaque, which eliminates the need for plantings.

What is missing is the color that will be applied to the fencing. In an earlier discussion with the Applicant's team, I believe that they agreed to a dark color, to be determined. The color should relate to the color of other functional elements used in Tuscan Village (e.g., signposts or traffic signals) to maintain continuity.

MAINTENANCE
The majority of the plantings shown on the Halvorson drawings are within the Liberty Utilities' property. Will they be responsible for the maintenance once the plantings have been established and accepted?

The Landscape Plan indicates a large area of 'Low Grasses and Perennials' on the east side of the substation facing Route 28. It appears that most (but not all) of this area is outside the Liberty Utilities' property line. This type of landscape treatment can be labor-intensive for the first few years to get the plants established. Who will be responsible for maintaining this highly visible location?

Are there plans to irrigate any of the plantings surrounding the substation? If so, please provide the design and layout information.

SUBSTATION NOISE
The Applicant has noted that information on possible noise from the substation will be provided by Liberty Utilities. While noise is not an issue that we deal with, if there was the need for mitigation measures related to noise generated by the project (e.g., sound barriers), we should be aware of their physical design and comment accordingly.

Please contact me if you have any questions.

Terry DeWan FASLA
Terrence J. DeWan & Associates

Liberty Utilities

Capital Project Business Case 2019

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation Transmission Supply	**Date Prepared:**	1/9/2019
Project ID#:	8830-1965	**Cost Estimate:**	$200,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2019
Prepared By:	Joel Rivera	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.

In 2019 it is planned to design the installation of two (2) 2.2 miles of 115kV transmission line extension with 23kV distribution under build along the Salem Rail Track.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase or worsening of components exceeding planning and operating criteria.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed business park development in the range of 14MW – 17MW located at the former Rockingham Park Track.

The recommended plan accomplishes all system capacity and asset replacement requirements. Upon completion of the projects within the Salem Area Study, Baron Ave and Salem Depot substations will be retired. The plan will be achieved in three (3) phases. This business case is for Phase 2 of the Salem Area Study.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Liberty Utilities

Capital Project Business Case

2019

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2018	2019	Beyond 2019	Total
Internal Labour (including labour and travel)	$ -	$ -	$ 10,000	$ -	$ 10,000
Materials (including consumables)	$ -	$ -	$ -	$ -	$ -
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (including consultants)	$ -	$ -	$ 190,000	$ -	$ 190,000
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade for design activities on this project. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	12/31/2019

Risk Assessment
(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Liberty Utilities

Capital Project Business Case

2019

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Joel Rivera	JRR	3/5/19
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	CaRodrigues	3/5/19
Senior Vice President/ Vice President	Up to $500,000			
State President:	Up to $500,000			
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration	Peter Dawes	3/7/19

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Expenditure Form 2019

Project Name:	Rockingham Substation Transmission Supply		
Financial Work Order (FWO):		**Project ID #:**	8830-1965
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	1/9/2019
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2019
Prepared by:	Joel Rivera	**Requested Capital ($)**	$200,000
Planned or Unplanned Projects:	☒ Planned ☐ Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.
In 2019 it is planned to design the installation of two (2) 2.2 miles of 115kV transmission line extension with 23kV distribution under build along the Salem Rail Track.

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (iif known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

Yes. As part of this project poles and overhead wires will be removed along the 23kV sub transmission right of way. Replacement costs will be determined during detailed design activity. The plant being removed is not usable. Answers to questions 1, 3 and 5 are unknown at this time.

What alternatives were evaluated and why were they rejected?

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Liberty Utilities

Capital Project Expenditure Form 2019

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Complete the Financial Summary table only if:
- Project is less than $100,000; or
- Project category is *Mandated* or *Safety* (Business Case Form not required)

Financial Summary

Next Anticipated Test Year		**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: [i]	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		

Category	Current Year	Future Years	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)			

Liberty Utilities

Capital Project Expenditure Form 2019

Approvals and Signatures [ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Joel Rivera Joel Rivera	JJR	3/5/19
Senior Manager:	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	C Rodrigues	3/5/19
Senior VP/VP:	Up to $500,000			
State President:	Up to $500,000			
Regional President:	Up to $3,000,000			
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration:	All Requests	Peter Dawes VP, Finance & Administration	Peter Dawes	3/7/19

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Change Order Form

2019

Project Overview			
Reason for Change: Reference 2019 Capital spend report. GSE capital portfolio was reallocated mid-year.			
Project ID:	8830-1965	**Project Name:**	Rockingham Substation Transmission Supply
Change Order Name:	Rockingham Substation Transmission Supply 2019 #1	**Date Prepared:**	8/3/2023
Change Order #:	8830-1965 #1	**Financial Work Order (FWO):**[i]	
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2023
Prepared By:	Ryan Patnode	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$200,000**		**$200,000**	**$400,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Reference 2019 Capital spend report. GSE capital portfolio reallocated mid-year.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)

Change Order Form

2019

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000			
State President / Senior VP / VP:	Up to $500,000	Neil Proudman NH President		
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Project Close Out Report 2019

Requesting Region or Group:	Granite State Electric Co.	**Date of Closeout (MM/DD/YY):**	03/10/2020
Project Name:	Rockingham Substation Transmission Supply		
Project ID#:	8830-1965	**Requesting Region:**	East Region
Project Lead:	Anthony Strabone	**Project Sponsor:**	Charles Rodrigues
Project Status	X In Service C Complete ☐ Closed		
Project Start Date:	01/01/2019	**Project Completion Date:**	12/31/2019
Requested Capital ($)	$ 200,000	**Expenditure Included in Approved Budget?**	X Yes ☐No

Section 1. Approval

Approval of the Project Closeout and Assessment Report indicates an understanding and formal agreement that the project is ready to be closed. By signing this document, each individual agrees all administrative, financial, and logistical aspects of the project should be concluded, executed, and documented as described herein.

Further, by signing this Report, it is accepted that CWIP (FERC Account 107) should be transferred to Utility in Plant Service (FERC Account 101)

Approver Name	Title	Signature	Date
Anthony Strabone	Project Lead	Anthony Strabone	03/30/2020
Charles Rodrigues	Project Sponsor		
Mark Parker	Operations Manager		
Phil Greene	Accounting Manager		

Section 2. Final Deliverable/Deployment Checklist

Sponsor to respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question	Response
2.1	Do you agree that the product and/or service is ready to be deployed?	Yes ☒ No ☐
2.2	Do you agree the product and/or service has sufficiently met the stated business goals and objectives?	Yes ☒ No ☐
2.3	Do you fully understand and agree to accept all operational requirements, operational risks, maintenance costs, and other limitations and/or constraints imposed as a result of ongoing operations of the product and/or service?	Yes ☒ No ☐
2.4	Has the final unitization estimate been provided to Property Accounting?	Yes ☒ No ☐

Project Close Out Report 2019

Item	Question	Response
2.5	Do you agree the project should be closed? If no, please explain:	Yes ☒ No ☐
	Scale of 1 thru 5; 5 = highest	
	Rate your level of satisfaction with regards to the project outcomes listed below	
2.5	Project Quality	3/5
2.6	Product and/or Service Performance	3/5
2.7	Scope	3/5
2.8	Cost (Budget)	2/5
2.9	Schedule	3/5

Section 3. Project Documentation Checklist

Project Manager Respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question		Response
3.1	Have project documentation and other items (e.g., Business Case, Project Plan, Charter, Budget Documents, Status Reports) been prepared, collected, filed, and/or disposed?		Yes ☒ No ☐
3.3[i]	Were audits (e.g., project closeout audit) completed and results documented for future reference?		Yes ☒ No ☐
3.4	Identify the storage location for the following project documents items:		
Item	**Document**	**Location (e.g., Google Docs, Webspace)**	**Format**
3.4a	Business Case	W:\Engineering\Electric Engineering\Electric Planning Engineering\2 - Planning	☒ Electronic ☐ Manual
3.4b	If available, the Final Project Schedule	N/A	☐ Electronic ☐ Manual
3.4c	Budget Documentation and Invoices	W:\Public\Accounts Payable\New Hampshire	☒ Electronic ☐ Manual
3.4d	Status Reports	N/A	☐ Electronic ☐ Manual
3.4e	Risks and Issues Log	N/A	☐ Electronic ☐ Manual
3.4f	Final deliverable	N/A	☐ Electronic ☐ Manual
3.4g	If applicable, verify that final project deliverable for the project is attached or storage location is identified in 3.4.		

Section 4. Project Team [ii]

Project Manager to list resources specified in the Project Plan and used by the project.

Name	Role	Type (e.g., Contractor, Employee)
Anthony Strabone	Engineering	Employee
Joel Rivera	Engineering	Employee
TRC	Engineering	Contractor

Section 5. Project Lessons Learned

Project Team to identify lessons learned specifically for the project. State the lessons learned in terms of a problem (issue).If available please include a Lesson Learned Log in the attached.. Please summarize the top three issues on the project and the recommended improvements to correct a similar problem in the future.

Problem Statement	Problem Description	References	Recommendation
None	None	None	None

Section 7. Open Issues

Project Manager and Functional Lead to describe any open issues and plans for resolution within the context of project closeout. Include an open issue for any "no" responses in the Final Product and/or Service Acceptance Checklist and the Project Artifacts Checklist sections.

Issue	Planned Resolution
Re-allocation of charges due to charges being applied to the wrong project	Continue to work with folks working on the project to ensure invoices charges are properly applied to the correct work order
Actual burden rate higher than budgeted	Continue to work with Finance to received accurate burden rates

Section 8. Project Cost Summary

Project Manager and Functional Lead to provide details for the following tables.

Cost Category	1- Budget	2- Actual	3 = 1 -2 Variance
Cost of Design & Engineering ($)		$ 1,936.65	

Project Close Out Report | 2019

Cost of Materials ($)		$ (199,734.00)	
Cost of Construction ($)		$ 0	
External Costs ($)		$ 269,605.27	
Internal Costs ($)		$ 0	
Other (burdens $)		$ 181,534.15	
CIAC		$ 0	
AFUDC		$ 47,887.16	
Total Project Costs ($)	$ 200,000	$ 301,229.23	$ (101,229.23)

Reasons for Variance	**Impact**
See Change Form-reclass of charges and Charges	$ 225,346.37
Cause 2	$
Cause 3	$

Project Manager to list of all work orders associated with project that should be closed once Close Out Report is accepted.

Registry of All Job Codes (Regional, Corporate, LABs)
Various

[i] This section assumes an accounting audit has been completed ensuring all outstanding payments have been reconciled to the project
[ii] For Section 4 in filling out the Project Team Section, for those projects following the materiality limit set forth in the work order approval limits greater than $5M please complete this section, all other projects do not require this.

Liberty Utilities

Capital Project Business Case 2020

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation Transmission Supply	**Date Prepared:**	2/2/2019
Project ID#:	8830-1965	**Cost Estimate:**	$500,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2019
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2022
Prepared By:	Joel Rivera	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115kV supply lines, 115/13.2 kV - 33/44/55 MVA transformers, two 7.2 MVAR capacitor banks and 13.2kV metal clad switchgear. The new Rockingham Substation will be constructed at company owned land, neighboring the Tuscan Village Development. This substation will allow the retirement of the Salem Depot Substation given its issues with age and condition of the assets.

In 2020 it is planned to complete the design and procurement phase of the substation project. It will also include substation site work.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment, particularly in the Tuscan Village Development. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The new demand from the development is estimated at 17 MW. The loading of the system will increase to where various components (feeders, transformers and supply lines) will exceed certain planning and operating criteria. For a list of planning criteria violations expected to be exceeded with the upcoming load expansions see 2022 Planning Criteria Violations – Salem Area.pdf
See related projects Rockingham Substation and Rockingham Distribution Feeders.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed Tuscan Village Development in the range of 17MW located at the former Rockingham Park Track.

This project will provide the required capacity to supply the upcoming customer expansions and will resolve all identified criteria violations for the town of Salem. It will also resolve all issues with asset condition at the Salem Depot Substation and make way for future investments in distribution automation and grid modernization.

This business case covers Phase 2 of the Salem Area Study which recommends the 2.5 mile construction of two new 115kV supply lines between the Golden Rock #19 Substation and the new Rockingham #21 Substation. Each supply line will be extended along an existing 23kV right-of-way corridor and will include a 23kV underbuilt supply line and pilot wire for communications.

The construction of one 115kV supply line with a 23kV underbuilt supply line will begin in the fall of 2020 and will be completed by summer of 2021. The second 115kV supply line with a 23kV underbuilt supply line will begin construction in the fall of 2021 and will be completed by the summer of 2022.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

This project is part of the Salem Area Study. For details on alternatives considered refer to Appendix A and Section 4 of the Salem Area Report.

Financial Assessment/Cost Estimates

(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2020	2021	Beyond 2021	Total
Internal Labour (including labour and travel)	$ -	$ 25,000	$ -	$ -	$ 25,000
Materials (including consumables)	$ -	$ 275,000	$ -	$ -	$ 275,000
Equipment (rental equipment)	$ -	$ -	$ -	$ -	$ -
Contactor/Subcontractor (including consultants)	$ -	$ 200,000	$ -	$ -	$ 200,000
AFUDC ($)					
Total Project Costs ($)	$ -	$ 500,000	$ -	$ -	$ 500,000

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade. Project grade estimates for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule

(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	4/1/2020
Procure Long Lead Items	3/1/2020	6/1/2020
Construction	10/1/2020	6/1/2022

Risk Assessment

(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits. The risk of equipment failure due to age and condition of the Salem Depot substation assets will increase if this project is delayed. The ability for the Company to restore load during emergencies and the ability to re-route power to perform routine maintenance will be compromised if this project is not completed or is delayed.

The construction of the two 115kV supply lines will be performed in two phases to allow careful coordination of outages. The first phase will require taking out of service the 23kV 2352 supply line to install a new 115kV supply line in its place. This will require the alternate supply line 2393 to supply its load during construction of the new 115kV supply line between fall of 2020 and May 2021. There is a risk of prolonged outages and difficulties in restoring load if the 2393 supply line loses power during this construction phase.

The second phase will require taking out of service the 23kV 2393 and 2353 supply lines to install the second 115kV supply line in their place. This will require the alternate newly built supply line 2352 to supply its load during construction of the new 115kV supply line between fall of 2021 and May 2022, at a point where the system demand is increased as the Tuscan Village development expands. This newly built supply line 2352 will be of lower ampacity rating than that exists today to match the reduced loading requirements on the 23kV system after construction of the Rockingham #21 Substation. This lower ampacity creates a risk of overload and ability to obtaining planned outages for construction. It also creates a dependency to complete the associated substation and distribution feeder projects to enable reducing load of the 23kV supply system that will enable the completion of the 115kV transmission lines.

This project has a risk score of 50.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Supporting Documentation
(Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)

Please reference the following supporting documents:
2022 Planning Criteria Violations - Salem Area.pdf
Salem Area Study Report.pdf
23kV Supply System Salem.pdf
Liberty 115kV Lines Conceptual Structure Outlines.pdf
23kV Outage Plan Proposed.xlsx

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering		03/04/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering		2/25/2020
Senior Vice President/ Vice President	Up to $500,000	Richard MacDonald Vice President, Operations		2/21/2020
Senior Vice President/ Vice President	Up to $500,000	Susan Fleck President, NH		2/26/2020
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to			

	$5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Capital Project Expenditure Form 2020

Project Name:	Rockingham Substation Transmission Supply		
Financial Work Order (FWO):		**Project ID #:**	8830-1965
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	1/10/2020
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2020
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2020
Prepared by:	Joel Rivera	**Requested Capital ($)**	$500,000
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and eight 13.2kV feeders at the former Rockingham Race Track and the retirement of Salem Depot Substation.
In 2020 it is planned to complete the design and procurement phase of the substation project. It will also include substation site work.

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:
1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

Yes. As part of this project poles and overhead wires will be removed along the 23kV sub transmission right of way. Replacement costs will be determined during detailed design activity. The plant being removed is not usable. Answers to questions 1, 3 and 5 are unknown at this time.

What alternatives were evaluated and why were they rejected?

A total of twelve (12) plans were evaluated to address the existing and future system needs of the area. Six (6) of these plans were eliminated because of transmission costs and construction challenges due to site locations; refer to Appendix A under the Salem Area Report for a list of all Eliminated Plans. Five (5) Alternate plans were developed and weighed against the Recommended Plan. The Five (5) Alternate Plans are detailed in Section 7 and the Recommend Plan is detailed in Section 4 of the Salem Area Report.

Liberty Utilities

Capital Project Expenditure Form 2020

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Complete the Financial Summary table only if:
- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year		**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: [i]	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$500,000		

Liberty Utilities WATER GAS ELECTRIC

Capital Project Expenditure Form 2020

Approvals and Signatures [ii]

Approved By:				
Role	Approval Limit	Name	Signature	Date
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	03/04/2020
Senior Manager:	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	CA Rodrigues	2/25/2020
Senior VP/VP:	Up to $500,000	Richard MacDonald Vice President, Operations	Richard MacDonald	2/21/2020
State President:	Up to $500,000	Susan Fleck President NH		2/26/2020
Regional President:	Up to $3,000,000			
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration:	All Requests	Peter Dawes VP, Finance & Administration		

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Change Order Form | 2020

Project Overview			
Reason for Change: Budget Increase to fund project to accommodate work associated with Rockingham Substation Transmission Supply			
Project ID:	8830-1965	**Project Name:**	Rockingham Substation Transmission Supply
Change Order Name:	Budget Increase	**Date Prepared:**	07/27/2020
Change Order #:	8830-1965-01	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2020
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$500,000**		**$150,000**	**$650,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount: *Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc)*
Additional funding is requested to account for increase in costs associated with the Revised Salem Area Study as required per the NHPUC in Order Number 26,377 and securing of additional easements required for the Company to construct and maintain structures associated with this project.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)
N/A	N/A	N/A

Liberty Utilities

Change Order Form

2020

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	07/27/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2020.07.29 16:58:52 -04'00'	
State President / Senior VP / VP:	Up to $500,000	Richard MacDonald, VP Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2020.07.31 09:19:34 -04'00'	
Regional President:	Up to $3,000,000	~~Susan Fleck~~ ~~President, NH~~	[illegible]	10/8/2020
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

[iv] In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities

Change Order Form

2020

Project Overview			
Reason for Change: Increase to fund project to accommodate work associated with Rockingham Substation Transmission supply.			
Project ID:	**8830-1965**	**Project Name:**	Rockingham Substation Transmission Supply
Change Order Name:	**8830-1965 - #3**	**Date Prepared:**	2/1/2021
Change Order #:	**8830-1965**	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	1-1-2020
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/30/2020
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$500,000**	$1,250,000	$54,061	$1,804,061

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Previous charge order requested additional funding to account for increase in costs associated with revised Salem area study as required per the NHPUC in order number 26,377 and securing of additional easement required for company to construct and maintain structures associated with this project . This change order amount of $1,100,000 was due to an intentional reallocation of funds from project 8830-2069. Construction for project 8830-2069 was postponed and the remaining capital funds were transferred to this project for material procurement. This revised change order is to account for direct and indirect costs associated with actual charges that were slightly greater than estimated for yearend projection.
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Liberty Utilities WATER | GAS | ELECTRIC

Change Order Form

2020

Schedule Impacts (As a result of the Change Order, where applicable, List the Impacts to schedule)		
Baseline Schedule (BL)	**New Forecast (NF)**	**Variance (BL – NF)**
N/A	N/A	N/A

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000	Anthony Strabone Senior Manager Electric Engineering	Anthony Strabone	02/01/2021
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.02.03 08:28:17 -05'00'	
State President / Senior VP / VP:	Up to $500,000	Richard Macdonald, VP operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2021.02.03 14:33:21 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney East Region President		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
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iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

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Change Order Form

2020

Project Overview			
Reason for Change: Budget Increase to fund project to accommodate work associated with Rockingham Substation Transmission Supply			
Project ID:	8830-1965	**Project Name:**	Rockingham Substation Transmission Supply
Change Order Name:	Budget Increase	**Date Prepared:**	11/04/2020
Change Order #:	8830-1965-02	**Financial Work Order (FWO):**[i]	Various
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2020
Prepared By:	Anthony Strabone	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	2020 Capital Budget

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$500,000**	**$150,000**	**$1,100,000**	**$1,750,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Provide brief explanation on basis of the requested amount (i.e. revised contract amount, estimate based on revised engineering design, etc)
Previous change order requested additional funding to account for increase in costs associated with the Revised Salem Area Study as required per the NHPUC in Order Number 26,377 and securing of additional easements required for the Company to construct and maintain structures associated with this project. This change order amount of $1,100,000 was due to an intentional reallocation of funds from project 8830- 2069. Construction for project 8830-2069 was postponed and the remaining capital funds were transferred to this project for material procurement.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)
N/A	N/A	N/A

Liberty Utilities WATER | GAS | ELECTRIC

Change Order Form

2020

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Anthony Strabone Manager, Electric Engineering	Anthony Strabone	11/04/2020
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2020.11.05 08:00:38 -05'00'	
State President / Senior VP / VP:	Up to $500,000	Richard MacDonald, VP Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2020.11.18 17:19:51 -05'00'	
Regional President:	Up to $3,000,000	Susan Fleck President, NH		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities — Capital Project Business Case 2021

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation Transmission Supply	**Date Prepared:**	1/4/2021
Project ID#:	8830-1965	**Cost Estimate:**	$6,000,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2021
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2021
Prepared By:	Joel Rivera	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes)**:**	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Substation and the retirement of Salem Depot #9 Substation.

In 2021 it is planned to construct one (1) 2.2 miles of 115kV transmission line extension with 23kV distribution under build along the Salem Rail Track.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The town of Salem, NH will experience more than expected load growth in the upcoming years. This is due to commercial redevelopment. This area consists of expansive residential developments, numerous retail plazas, office parks and Industrial/Commercial Parks. The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase or worsening of components exceeding planning and operating criteria. In addition the testing of several substation transformers in the town of Salem have shown signs of gassing and continued deterioration.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition it determines the distribution requirements needed to supply the proposed business park development in the range of 12MW – 18MW located at the Tuscan Village Development.

The recommended plan accomplishes all system capacity and asset replacement requirements. Upon completion of the projects within the Salem Area Study, Baron Ave and Salem Depot substations will be retired.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

For details on alternatives considered, refer to the 2020 Salem Area Study.

Financial Assessment/Cost Estimates

(Double click embedded excel file to update; include contingency allowance in excel file)

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Business Case 2021

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2020	2021	Beyond 2021	Total
Internal Labour (including labour and travel)	$ -	$ -	$ 10,000	$ -	**$ 10,000**
Materials (including consumables)	$ -	$ -	$ 2,060,000	$ -	**$ 2,060,000**
Equipment (rental equipment)	$ -	$ -	$ -	$ -	**$ -**
Contactor/Subcontractor (including consultants)	$ -	$ -	$ 3,930,000	$ -	**$ 3,930,000**
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade for design activities on this project. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2018	12/31/2019
Construction Start	4/1/2021	12/31/2021

Risk Assessment
(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits.
Continued deterioration of substation assets increase the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Supporting Documentation
(Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink

to file located on shared server or SharePoint)
Supporting Documentation can be found at W:\Engineering\Electric Engineering\Electric Planning Engineering

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000	Anthony Strabone Senior Manager, Electric Engineering	Anthony Strabone	01/14/2021
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.01.15 10:06:18 -05'00'	
Senior Vice President/ Vice President	Up to $500,000	Richard MacDonald Vice President, Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2021.01.15 15:17:54 -05'00'	
State President:	Up to $500,000	Susan Fleck President, NH	Susan Fleck Digitally signed by Susan Fleck Date: 2021.02.08 15:08:56 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney President, East Region		
Corporate - Sr VP Operations:	Up to $5,000,000	Gerald Tremblay Senior Vice President, Operations		
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston Chief Operating Officer		
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Expenditure Form 2021

Project Name:	Rockingham Substation Transmission Supply		
Financial Work Order (FWO):		**Project ID #:**	8830-1965
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	1/4/2021
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	1/1/2021
Project Lead:	Anthony Strabone	**Project End Date:**	12/31/2021
Prepared by:	Joel Rivera	**Requested Capital ($)**	$6,000,000
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request

Project description
The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Substation and the retirement of Salem Depot #9 Substation. In 2021 it is planned to construct one (1) 2.2 miles of 115kV transmission line extension with 23kV distribution under build along the Salem Rail Track.

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.
Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?
Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?
GUIDANCE: If yes, please detail the specific assets that will be removed: 1. *Original Cost of Plant to be removed (if known):* 2. *What is the replacement cost of the plant being removed (if original cost not known)?* 3. *Original Work Order of Plant to be removed (if known):* 4. *Is the Plant being removed reusable?* 5. *What is the year of original installation of the plant being removed*
Yes. As part of this project poles and overhead wires will be removed along the 23kV sub transmission right of way. Replacement costs will be determined during detailed design activity. The plant being removed is not usable. Answers to questions 1, 3 and 5 are unknown at this time.

What alternatives were evaluated and why were they rejected?
For details on alternatives considered, refer to the 2020 Salem Area Study.

Capital Project Expenditure Form 2021

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits. Continued deterioration of substation assets increase the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Complete the Financial Summary table only if:

- ≠ **Project is less than $100,000; or**
- ≠ **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: i	☐Fixed or Firm Price ☐Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$6,000,000		

Capital Project Expenditure Form 2021

Approvals and Signatures [ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager:	Up to $50,000	Anthony Strabone Senior Manager, Electric Engineering	Anthony Strabone	01/14/2021
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.01.16 08:36:55 -05'00'	
Senior VP/VP:	Up to $500,000	Richard MacDonald Vice President, Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2021.01.22 11:50:17 -05'00'	
State President:	Up to $500,000	Susan Fleck President, NH	Susan Fleck Digitally signed by Susan Fleck Date: 2021.02.08 15:04:56 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney President, East Region	[signature]	
Corporate – Sr. VP Operations:	Up to $5,000,000	Gerald Tremblay Senior Vice President, Operations		
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston Chief Operating Officer		
Finance (East) – Vice President, Finance & Administration:	All Requests	Peter Dawes VP, Finance & Administration		

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities
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Change Order Form

2021

Project Overview			
Reason for Change: Budget Increase accommodate work associated with construction of this project			
Project ID:	8830-1965	**Project Name:**	Rockingham Substation Transmission Supply
Change Order Name:	8830-1965 Rockingham Substation Transmission Supply	**Date Prepared:**	
Change Order #:	8830-1965	**Financial Work Order (FWO):**[i]	
Project Sponsor:	Neil Proudman	**Revised Start Date:**	1/1/2020
Project Lead:	Anthony Strabone	**Revised End Date:**[ii]	12/31/2023
Prepared By:		**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☒ No	**If No is Selected, Please specify source of funds**[iv]	8830-1964 Golden Rock Sub $358K 8830-2123 Distributed Generation Blanket $15K

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$6,000,000**		**$373,000**	**$6,373,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

Over expenditure is being driven by direct and indirect costs associated with construction and environmental oversight and materials. The anticipated overspend of this project will be offset by underspend of other capital projects and therefore will not impact the overall 2021 GSE Capital Budget

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)

Liberty Utilities
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Change Order Form

2021

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000			
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000			
State President / Senior VP / VP:	Up to $500,000	Neil Proudman NH President	Neil Proudman Digitally signed by Neil Proudman Date: 2023.08.03 13:57:17 -04'00'	
Regional President:	Up to $3,000,000	Vincent Gaeto Regional East President	Vincent Gaeto Digitally signed by Vincent Gaeto Date: 2023.08.03 15:32:05 -04'00'	
Corporate - Sr VP Operations:	Up to $5,000,000	Gerald Tremblay, Sr Vice President Operations		August 4th, 2023
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston, Chief Operating Officer		August 4, 2023

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty

Capital Project Business Case

2022

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Rockingham Substation Transmission Supply	**Date Prepared:**	02/11/2022
Project ID#:	8830-1965	**Cost Estimate:**	$9,000,000
Project Sponsor:	Christopher Steele	**Project Start Date:**	01/01/2022
Project Lead:	Melvin Emerson	**Project End Date:**	12/31/2022
Prepared By:	Melvin Emerson	**Planned or Unplanned Projects:**	☒ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Substation and the retirement of Salem Depot #9 Substation. The scope of this project is to install approximately 2.5 miles of 115 kV covered wire in spacer cable configuration, which is the first commercial use of its kind. This line is the second 115 kV supply line to our recently constructed Rockingham Substation in Salem NH and is the last major project identified in the Salem Area Study addressing the area's asset concerns, system resiliency, capacity constraints, and modernization of the area's antiquated electric system.

In addition to the 2.2 miles of 115kV transmission line extension, the existing 23 KV circuit will be replaced with an underbuilt 23 KV spacer distribution circuit along the Salem Rail Track utilizing the same structures as the 115 KV circuit.

Background

(Insert description of current operational arrangement, and brief history of project & asset)

The Town of Salem has experienced significant transformation of the past several years which can be mostly attributed to Tuscan Village, which will deliver 3,800,000 ft^2 of new building use. The Tuscan Development Team has indicated that the presence of a reliable electric infrastructure has enable them to attract many clients, in particular a potential high energy user to be located in the Life Science Campus of the Tuscan Development. This single customer will be over a million ft^2 of Research, Development, and Manufacturing and hopes to obtain Town Approval in the first quarter of 2022 with groundbreaking to follow shortly after.
The loading of the system has changed over the years to where various components are at or have exceeded certain planning and operating criteria. In addition, sub-transmission facilities in the area are approaching its design limits. The upcoming developments in the area result in an increase or worsening of components exceeding planning and operating criteria. In addition, the testing of several substation transformers in the town of Salem have shown signs of gassing and continued deterioration.

Recommendation/Objective

(Insert the unique problem this project is looking to resolve)

The Salem Area Study was carried out to study options for the development of the power distribution system in the Salem, NH area. It determines the best engineering solution to mitigate overloads, address contingencies, and to upgrade/replace vintage assets in the system. In addition, it determines the distribution requirements needed to supply the proposed business park development in the range of 12MW – 18MW located at the Tuscan Village Development.

The recommended plan accomplishes all system capacity and asset replacement requirements. Upon completion of the projects within the Salem Area Study, Baron Ave and Salem Depot substations will be retired.

Liberty | Capital Project Business Case | 2022

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

For details on alternatives considered, refer to the 2020 Salem Area Study

Financial Assessment/Cost Estimates

(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No

Regulatory Lag (Click appropriate box): ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2021	2022	Beyond 2022	Total
Internal Labour (including labour and travel)	$ -	$ -	$ 15,000	$ -	**$ 15,000**
Materials (including consumables)	$ -	$ -	$ 3,090,000	$ -	**$ 3,090,000**
Equipment (rental equipment)	$ -	$ -	$ -	$ -	**$ -**
Contactor/Subcontractor (including consultants)	$ -	$ -	$ 5,895,000	$ -	**$ 5,895,000**
AFUDC ($)					
Total Project Costs ($)	**$ -**	**$ -**	**$ 9,000,000**	**$ -**	**$ 9,000,000**

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *This estimate is of investment grade for design activities on this project. A project grade estimate for construction will be provided upon completion of detailed design.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule

(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Detailed Design	6/1/2021	12/31/2021
Construction Start	4/1/2022	12/31/2022

Risk Assessment

(Please describe the risk of not completing the project)

Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits. Continued deterioration of substation assets increases the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Trade Finance

(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

Unknown

Liberty | Capital Project Business Case | 2022

Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)
Supporting Documentation can be found at W:\Engineering\Electric Engineering\Electric Planning Engineering

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Melvin Emerson Capital Lead	Melvin Emerson	02/11/2022
Senior Manager:	Up to $50,000	Anthony Strabone Sr Manager, Electric Engineering	Anthony Strabone	02/11/2022
Senior Director/Director:	Up to $250,000	Christopher Steele Sr. Director, Electric Operations	Christopher Steele Digitally signed by Christopher Steele Date: 2022.02.17 15:48:35 -05'00'	
Senior Vice President/ Vice President:	Up to $500,000			
State President:	Up to $500,000	Neil Proudman President, NH	Neil Proudman Digitally signed by Neil Proudman Date: 2022.02.28 12:56:15 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney President, East Region	James M. Sweeney Digitally signed by James M. Sweeney Date: 2022.03.01 10:17:45 -05'00'	
Corporate - Sr VP Operations:	Up to $5,000,000	Gerald Tremblay Senior Vice President, Operations		
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston Chief Operating Officer		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty

Capital Project Expenditure Form **2022**

Project Name:	Rockingham Substation Transmission Supply		
Financial Work Order (FWO):		**Project ID #:**	8830-1965
Requesting Region or Group:	Granite State Electric Co.	**Date of Request (MM/DD/YY):**	2/11/2022
Project Sponsor:	Christopher Steele	**Project Start Date:**	01/01/2022
Project Lead:	Melvin Emerson	**Project End Date:**	12/31/2022
Prepared by:	Melvin Emerson	**Requested Capital ($)**	$9,000,000
Planned or Unplanned Projects:	☒ Planned ☐ Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☒ Growth ☐ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Details of Request Rockingham Substation Transmission Supply

Project description

The second phase of the Salem Area Study proposes the installation of two new 115/13.2 kV - 33/44/55 MVA transformers and five 13.2kV feeders at the new Rockingham #21 Substation and the retirement of Salem Depot #9 Substation. The scope of this project is to install approximately 2.5 miles of 115 kV covered wire in spacer cable configuration, which is the first commercial use of its kind. This line is the second 115 kV supply line to our recently constructed Rockingham Substation in Salem NH and is the last major project identified in the Salem Area Study addressing the area's asset concerns, system resiliency, capacity constraints, and modernization of the area's antiquated electric system.

In addition to the 2.2 miles of 115kV transmission line extension, the existing 23 KV circuit will be replaced with an underbuilt 23 KV spacer distribution circuit along the Salem Rail Track utilizing the same structures as the 115 KV circuit.

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

Yes. This project supports and is aligned with the planned customer expansions at the Tuscan Village Park in Salem NH.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Permitting and/or Easement requirements will be undertaken during detailed design activities as applicable.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*
5. *What is the year of original installation of the plant being removed*

Yes. As part of this project poles and overhead wires will be removed along the 23kV sub transmission right of way. Replacement costs will be determined during detailed design activity. The plant being removed is not usable. Answers to questions 1, 3 and 5 are unknown at this time.

Liberty | Capital Project Expenditure Form | 2022

What alternatives were evaluated and why were they rejected?
For details on alternatives considered, refer to the 2020 Salem Area Study.

What are the risks and consequences of not approving this expenditure?
Not completing this project could result in the Company not being able to supply new customer growth in the area and/or could result in distribution facilities operating above their design limits. Continued deterioration of substation assets increases the safety risk to company personnel and the public. Transformer testing has shown deterioration of the transformer insulation and failure could result in extended outages. There are no spare transformers available if a failure were to occur.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
Health, Safety and Security will be addressed using Engineering designs/controls during the detailed design process if applicable.

Are there other pertinent details that may affect the decision making process?
No

Liberty | Capital Project Expenditure Form | 2022

Complete the Financial Summary table only if:

- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☒ Yes ☐ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☒1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:	☐Fixed or Firm Price ☒Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$9,000,000		

Liberty | Capital Project Expenditure Form | 2022

Approvals and Signatures [ii]

Approved By:				
Role	Approval Limit	Name	Signature	Date
Manager / Staff (requisitioner/buyer):	Up to $25,000	Melvin Emerson Capital Lead	Melvin Emerson	02/11/2022
Senior Manager:	Up to $50,000	Anthony Strabone Sr Manager, Electric Engineering	Anthony Strabone	02/11/2022
Senior Director/Director:	Up to $250,000	Christopher Steele Sr. Director, Electric Operations	Christopher Steele Digitally signed by Christopher Steele Date: 2022.02.17 15:47:52 -05'00'	
Senior VP/VP:	Up to $500,000			
State President:	Up to $500,000	Neil Proudman President, NH	Neil Proudman Digitally signed by Neil Proudman Date: 2022.02.28 12:56:50 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney President, East Region	James M. Sweeney Digitally signed by James M. Sweeney Date: 2022.03.01 10:18:49 -05'00'	
Corporate – Sr. VP Operations:	Up to $5,000,000	Gerald Tremblay Senior Vice President, Operations		
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston Chief Operating Officer		

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 5

Date Request Received: 7/27/23 Date of Response: 8/10/23
Request No. DOE 5-3 Respondent: Anthony Strabone

REQUEST:

Rockingham Transmission Supply. Reference the Company's response to DOE 2-13, specifically Attachments DOE 2-13.c.1 and DOE 2-13.c.3:

a. Is the $3,000,000 requested in Attachment DOE 2-13.c.3 (with a start date of Nov 1, 2021 and end date of Dec 31, 2023) in addition to the $9,000,000 requested in Attachment DOE 2-13.c.1 (with a start date of Jan 1, 2022 and end date of Dec 31, 2022)?

b. Please explain the differences in work scopes between Attachment DOE 2-13.c.1 and Attachment DOE 2-13.c.3.

c. Please provide the background and rationale for any additional transmission capacity requested in Attachment DOE 2-13.c.3.

RESPONSE:

a. No, the $3,000,000 in Attachment DOE 2-13.c.3 was included in the capital request of $9,000,000 in Attachment DOE 2-13.c.1.

b. The work scope identified in Attachments DOE 2-13.c.1 and DOE 2-13.c.3 are the same, which is to construct the second 115 KV supply line. Due to delivery delays of the steel structures, the Company was only able to receive material in 2022, resulting in the construction of the second line being delayed until 2023.

c. The Transmission capacity is the same in Attachment DOE 2-13.c.1 and Attachment DOE 2-13.c.3.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23 | Date of Response: 11/20/23
Request No: DOE TS 2-21 | Respondent: Anthony Strabone

REQUEST:

Regarding all electric vehicle (EV) charging stations owned by Liberty, please provide the following:

a. All business case documents, Company approvals, and other workpapers for all EV charging stations owned by Liberty.
b. The total detailed cost of the project associated with the purchase, installation, and other related costs, including infrastructure upgrades, of the EV chargers. If Liberty did not pay the total cost, please provide a detailed summary of the paying entity and associated costs.
c. Please provide the specific reference to the plant in service and specific account number for all costs and for all revenues received associated with each EV charger. Please cite the specific Bates number and line number in the rate case filing.
d. Please provide the operation and maintenance arrangements for each EV charging station and the associated costs including in the revenue requirement.
e. Please indicate where Liberty received approval by the NH PUC for the purchase and installation for each EV charging station, if applicable.
f. Please provide monthly usage data (in kWh and kW) for each station since installation.
g. Please indicate under which rate class each EV charger is billed.
h. Please provide total monthly revenue and total monthly distribution revenue received for the usage of each charging station since installation. If Liberty does not receive separate revenue for each EV charging station, please calculate the total monthly billed revenue and total billed distribution revenue based on the usage for each EV charging station and the rates in place at the time of usage.

RESPONSE:

a. Please see Attachment 23-039 DOE TS 2-21.a for the following:
    - 2020 Capex form and Business Case

Docket No. DE 23-039 Request No. DOE TS 2-21

- 2021 Capex form and Business Case
- 2021 Change Order
- 2022 Change Order
- 2022 Project Close Out form

b. Please see Attachment 23-039 DOE TS 2-21.b.xlsx for the breakdown of costs. Liberty paid all costs associated with the project. There were no infrastructure upgrades required as the area where the chargers were installed was new infrastructure.

c. The costs for the EV stations are booked to account 101 Plant in Service and included on Bates II-354, line 1. The revenues for the revenues received from the customer are booked to account 10442000 and included on Bates II-310, lines 6-11.

d. As part of the installation costs, Liberty paid ChargePoint for a five-year operation and maintenance plan for the single level 2 charger that has two ports. The Company has 24/7 monitoring, remote troubleshooting and service restoration at a cost of $2,246. Liberty also has access to cloud data for each port at the charger for $2,638. Liberty paid ChargePoint for a five-year operation and maintenance plan for the level 3 chargers, each with one port, that includes the following list. These costs were prepaid and are included in the revenue requirement as part of plant in service.

    - 5yr Prepaid Enterprise Cloud Plan $19,196 ($4,799 per charger): Prepaid Enterprise Cloud Plan subscription with advanced station management features such as: Station Activation, Custom Video uploads, and Automatic Software Updates, driver and fleet management features including: Access Control and Pricing & Automatic Payment Collection, as well as advanced energy and power management features which include: Time of Use Power Sharing and Energy Management APIs. Real-time dashboards and reports provided for applicable features including 15 min meter data readings and associated advanced energy reports.
    - 5 prepaid years of ChargePoint Assure for CPE250 station $57,660 (14,415 per station): Includes Parts and Labor Warranty, Remote Technical Support, On-Site Repairs when needed, Unlimited Configuration Changes, and Reporting.

e. The EV Chargers are among the many projects included in the Company's rate base under review as part of this distribution rate case.

f. Please see Attachment 23-039 DOE TS 2-21.f.xlsx for the requested data.

g. The level 2 charging station is billed under Rate G-3. The level 3 chargers are billed under Rate G-2.

h. Please see the Company's response to part f. There are two level 3 charging stations at each meter and the Company is unable to delineate which station is being used from the billing data.

Capital Project Expenditure Form 2020

Project Name:	Tuscan Village EV Chargers		
Financial Work Order (FWO):		**Project ID #:**	8830-2095
Requesting Region or Group:	East	**Date of Request (MM/DD/YY):**	6/24/2020
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	6/24/2020
Project Lead:	Heather Tebbetts	**Project End Date:**	12/31/2020
Prepared by:	Heather Tebbetts	**Requested Capital ($)**	$210,000
Planned or Unplanned Projects:	☐ Planned ☒Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☐ Regulatory Supported ☒ Discretionary		

Details of Request

Project description

The Tuscan Village development has requested EV charging station installations for customers utilizing the retail area of the development. The Company is working with ChargePoint to install one level 3 charger and two level 2 chargers. The level 3 charger will charge electric vehicles at 80% in approximately 20 minutes. The level 2 chargers will provide a charge of 25-30 miles of range per hour. The customer of the charging stations is Tuscan Village and will be responsible for the monthly electric bill. The chargers will be metered and billed under Rate G-2. Tuscan Village is installing all conduit necessary to install the chargers.

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

This is a customer connection project as the chargers will be metered and provide new load. The location of the chargers is within the Tuscan Village.

Level 2: at building 520, 120/208 volts. 2 cars
Level 3: at buildings 600 and 800, 277/480 volts, 2 cars at each

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

There aren't any permitting or environmental impacts. These are essentially services provided a commercial size customer, which happens to be a charging station.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?

GUIDANCE: If yes, please detail the specific assets that will be removed:

1. *Original Cost of Plant to be removed (if known):*
2. *What is the replacement cost of the plant being removed (if original cost not known)?*
3. *Original Work Order of Plant to be removed (if known):*
4. *Is the Plant being removed reusable?*

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Expenditure Form 2020

5. *What is the year of original installation of the plant being removed*
N/A

What alternatives were evaluated and why were they rejected?
The alternative is to not install chargers.

What are the risks and consequences of not approving this expenditure?
If Tuscan Village changes their mind on installation of the chargers, the chargers will not be purchased.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
N/A

Are there other pertinent details that may affect the decision making process?
Please see the attached quote from ChargePoint for further information.

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Expenditure Form 2020

Complete the Financial Summary table only if:

- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☒1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?	Rate case		
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:[i]	☐Fixed or Firm Price ☐Estimate – Internal ☒Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)	0		
Cost of Materials ($)	$182,000		
Cost of Construction ($)	$28,000		
External Costs ($)	0		
Internal Costs ($)	0		
Other ($)	0		
AFUDC ($)	0		
Total Project Costs ($)	$210,000		

Approvals and Signatures[ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tebbetts	Heather Tebbetts Digitally signed by Heather Tebbetts DN: cn=Heather Tebbetts, o=Liberty Utilities, ou=Regulatory, email=heather.tebbetts@libertyutilities.com, c=US Date: 2020.07.06 09:41:58 -04'00'	Click here to enter a date.
Senior Manager:	Up to $50,000			Click here to enter a date.
Senior Director/Director:	Up to $250,000	Charles Rodrigues	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2020.08.10 13:37:52 -04'00'	Click here to enter a date.
Senior VP/VP:	Up to $500,000			

Liberty Utilities Capital Project Expenditure Form 2020

State President:	Up to $500,000	Susan Fleck		Click here to enter a date.
Regional President:	Up to $3,000,000			Click here to enter a date.
Corporate – Sr. VP Operations:	Up to $5,000,000			Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			Click here to enter a date.

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Business Case 2020

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Tuscan Village EV Chargers	**Date Prepared:**	6/24/2020
Project ID#:	8830-2095	**Cost Estimate:**	$210,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	6/24/2020
Project Lead:	Heather Tebbetts	**Project End Date:**	12/31/2020
Prepared By:	Heather Tebbetts	**Planned or Unplanned Projects:**	☐ Planned ■ Unplanned
Project Type (click appropriate boxes)**:**	☐ Safety ☐ Mandated ☐ Growth ☐ Regulatory Supported ☒ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement
(Insert the scope of work, major deliverables, assumptions, and constraints)

The Tuscan Village development has requested EV charging station installations for customers utilizing the retail area of the development. The Company is working with ChargePoint to install two level 3 chargers and one level 2 charger. The level 3 charger will charge electric vehicles at 80% in approximately 20 minutes. The level 2 charger will provide a charge of 25-30 miles of range per hour. The customer of the charging stations is Tuscan Village and will be responsible for the monthly electric bill. The chargers will be metered and billed under Rate G-2. Tuscan Village is installing all conduit necessary to install the chargers.

Background
(Insert description of current operational arrangement, and brief history of project & asset)

The Company is working towards promoting electric vehicles through working with partners such as Tuscan Village.

Recommendation/Objective
(Insert the unique problem this project is looking to resolve)

Objective is to provide electric vehicle charging for customers of Tuscan Village in Salem.

Alternatives/Options
(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

If the Company does not own and install the chargers, charging stations will not be installed within Tuscan Village.

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Business Case

2020

Next Anticipated Test Year	**2021**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No
Regulatory Lag (Click appropriate box)	☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years		

Category	Total Already Approved	2020	2021	Beyond 2021	Total
Internal Labour (including labour and travel)	$ -	$ -	$ -	$ -	**$ -**
Materials (including consumables)	$ 182,000	$ -	$ -	$ -	**$ 182,000**
Equipment (rental equipment)	$ -	$ -	$ -	$ -	**$ -**
Contactor/Subcontractor (including consultants)	$ 28,000	$ -	$ -	$ -	**$ 28,000**
AFUDC ($)					

Unlevered Internal Rate of Return: Click here to enter text.

Basis of Estimate: *Tesla has provided costs associated with batteries. Cogsdale and internal labor costs have been provided internally.*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete: 0

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Conduit is installed in Tuscan Village for chargers by Tuscan	Fall 2020	12/31/2020

Risk Assessment
(Please describe the risk of not completing the project)

If Tuscan Village changes their mind on installation of the chargers, the chargers will not be purchased.

Trade Finance
(Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)

no

Supporting Documentation
(Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)

See the quote from ChargePoint for the max number of chargers (4 LEVEL 3, 2 LEVEL 2.) The scope of the project is two level 3 and one level 2 chargers.

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Business Case 2020

Approvals and Signatures [i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tebbetts Manager, Rates & Regulatory Affairs	Heather Tebbetts Digitally signed by Heather Tebbetts DN: cn=Heather Tebbetts, o=Liberty Utilities, ou=Regulatory, email=heather.tebbetts@libertyutilities.com, c=US Date: 2020.07.06 10:18:47 -04'00'	
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2020.08.10 13:37:09 -04'00'	
Senior Vice President/ Vice President	Up to $500,000	Richard MacDonald Vice President, Operations		
State President:	Up to $500,000	Susan Fleck President, NH		
Regional President:	Up to $3,000,000	James Sweeney President, East Region		
Corporate – Sr. VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			
Finance (East) – Vice President, Finance & Administration	All Requests	Peter Dawes VP, Finance & Administration		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Expenditure Form 2021

Project Name:	Tuscan Village EV Chargers		
Financial Work Order (FWO):		**Project ID #:**	8830-2095
Requesting Region or Group:	Granite State Electric	**Date of Request (MM/DD/YY):**	1/13/2021
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	6/24/2020
Project Lead:	Heather Tebbetts	**Project End Date:**	12/31/2021
Prepared by:	Ryan Patnode	**Requested Capital ($)**	$150,000
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☐ Regulatory Supported ☒ Discretionary		

Details of Request

Project description

The Tuscan Village development has requested EV charging station installations for customers utilizing the retail area of the development. The Company is working with ChargePoint to install one level 3 charger and two level 2 chargers. The level 3 charger will charge electric vehicles at 80% in approximately 20 minutes. The level 2 chargers will provide a charge of 25-30 miles of range per hour. The customer of the charging stations is Tuscan Village and will be responsible for the monthly electric bill. The chargers will be metered and billed under Rate G-2. Tuscan Village is installing all conduit necessary to install the chargers.

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

This is a customer connection project as the chargers will be metered and provide new load. The location of the chargers is within the Tuscan Village.
Level 3: at buildings 600 and 800, 277/480 volts, 1 car at each
This request builds an additional charger at buildings 600 and 800 as Charge Point indicated the trend is to install two level 3 chargers together to allow flexibility with customer usage.

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?

Liberty Utilities — Capital Project Expenditure Form 2021

There aren't any permitting or environmental impacts. These are essentially services provided a commercial size customer, which happens to be a charging station.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?
GUIDANCE: If yes, please detail the specific assets that will be removed: No 1. *Original Cost of Plant to be removed (if known):* 2. *What is the replacement cost of the plant being removed (if original cost not known)?* 3. *Original Work Order of Plant to be removed (if known):* 4. *Is the Plant being removed reusable?* 5. *What is the year of original installation of the plant being removed*

What alternatives were evaluated and why were they rejected?
The alternative is to not install chargers.

What are the risks and consequences of not approving this expenditure?
If Tuscan Village changes their mind on installation of the chargers, the chargers will not be purchased.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
N/A

Are there other pertinent details that may affect the decision making process?
Please see the attached quote from ChargePoint for further information.

Liberty Utilities Capital Project Expenditure Form **2021**

Complete the Financial Summary table only if:
- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☒1 – 3 years ☐Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?			
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:[i]	☐Fixed or Firm Price ☒Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$150,000		

Approvals and Signatures[ii]

Approved By:

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Expenditure Form 2021

Role	Approval Limit	Name	Signature	Date
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tebbetts Manager Rate & Regulatory Affairs	Heather Tebbetts Digitally signed by Heather Tebbetts DN: cn=Heather Tebbetts, o=Liberty Utilities, ou=Regulatory, email=heather.tebbetts@libertyutilities.com, c=US Date: 2021.03.18 09:22:37 -04'00'	Click here to enter a date.
Senior Manager:	Up to $50,000			Click here to enter a date.
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.03.19 07:38:33 -04'00'	Click here to enter a date.
Senior VP/VP:	Up to $500,000	Richard MacDonald Vice President Operations		
State President:	Up to $500,000	Susan Fleck President, NH		Click here to enter a date.
Regional President:	Up to $3,000,000	James Sweeney President East Region		Click here to enter a date.
Corporate – Sr. VP Operations:	Up to $5,000,000			Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			Click here to enter a date.

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Business Case

2021

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Tuscan Village EV Chargers	**Date Prepared:**	1/13/2021
Project ID#:	8830-2095	**Cost Estimate:**	$150,000
Project Sponsor:	Charles Rodrigues	**Project Start Date:**	6/24/2020
Project Lead:	Heather Tebbetts	**Project End Date:**	12/31/2021
Prepared By:	Ryan Patnode	**Planned or Unplanned Projects:**	☐ Planned x Unplanned
Project Type (click appropriate boxes)**:**	☐ Safety ☐ Mandated ☐ Growth ☐ Regulatory Supported ☒ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement
(Insert the scope of work, major deliverables, assumptions, and constraints)

The Tuscan Village development has requested EV charging station installations for customers utilizing the retail area of the development. The Company is working with ChargePoint to install two level 3 chargers and one level 2 charger. The level 3 charger will charge electric vehicles at 80% in approximately 20 minutes. The level 2 charger will provide a charge of 25-30 miles of range per hour. The customer of the charging stations is Tuscan Village and will be responsible for the monthly electric bill. The chargers will be metered and billed under Rate G-2. Tuscan Village is installing all conduit necessary to install the chargers.

Background
(Insert description of current operational arrangement, and brief history of project & asset)

The Company is working towards promoting electric vehicles through working with partners such as Tuscan Village.

Recommendation/Objective
(Insert the unique problem this project is looking to resolve)

Objective is to provide electric vehicle charging for customers of Tuscan Village in Salem.

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Capital Project Business Case 2021

Alternatives/Options
(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

If the Company does not own and install the chargers, charging stations will not be installed within Tuscan Village.

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No

Regulatory Lag
(Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☒1 to 3 years ☐Greater than 3 years

Category	Total Already Approved	2021	2022	Beyond 2021	Total
Internal Labor					
Materials					
Equipment					
Contractor/ Subcontractor		150,000			
AFUDC					
Total Project Cost		150,000			

Unlevered Internal Rate of Return:

Basis of Estimate: *Provide brief explanation on basis of estimate, activities completed to determine costs*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
Conduit is installed in Tuscan Village for chargers by Tuscan	6/1/2020	12/31/2021

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Capital Project Business Case

2021

Risk Assessment (Please describe the risk of not completing the project)
If Tuscan Village changes their mind on installation of the chargers, the chargers will not be purchased.
Trade Finance (Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)
No
Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)
See the quote from ChargePoint for the max number of chargers (4 LEVEL 3, 2 LEVEL 2.) The scope of the project is two level 3 and one level 2 chargers.

Approvals and Signatures[i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tebbetts Manager Rate & Regulatory Affairs	Heather Tebbetts Digitally signed by Heather Tebbetts DN: cn=Heather Tebbetts, o=Liberty Utilities, ou=Regulatory, email=heather.tebbetts@libertyutilities.com, c=US Date: 2021.01.14 07:43:29 -05'00'	
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues Director, Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.01.14 14:12:23 -05'00'	
Senior Vice President/ Vice President	Up to $500,000	Richard MacDonald Vice President Operations		
State President:	Up to $500,000	Susan Fleck President, NH		
Regional President:	Up to $3,000,000	James Sweeney President East Region		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

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Change Order Form

2021

Project Overview			
Reason for Change: Budget increase to fund project to accommodate work request third party attachments.			
Project ID:	8830-2095	**Project Name:**	~~GSE-Dist blanket~~ EV Charger Tuscan Ryan Patnode
Change Order Name:	8830-2095	**Date Prepared:**	3/19/2021
Change Order #:	8830-2095	**Financial Work Order (FWO):**[i]	
Project Sponsor:	Charles Rodrigues	**Revised Start Date:**	1/1/2020
Project Lead:	Heather Tebbets	**Revised End Date:**[ii]	12/31/2021
Prepared By:		**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☒ Yes ☐ No	**If No is Selected, Please specify source of funds**[iv]	

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$150,000**		**$150,000**	**$300,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount: *Added dollars. $300,000 represents 2021 funding request. In 2020 project was funded for $210,000.*
The 2021 request for $150,000 included the install cost for the level 2 and the cost to purchase and install two level 3 chargers. Tuscan has requested to install four level 3 chargers in 2021, thus the additional funding request of $150,000 is to purchase and install the additional two chargers. The money has been approved by the innovation fund.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)
Unplanned budgeted project approved in 2020 Approved 2020 $210,000	Due to delays in receiving the meter pedestal, the level 2 charging station was not installed in 2020, but was installed in March 2021.	

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Change Order Form

2021

2020 Funding $210,000	Actual 2020 spend $21,838	$188,162
Innovation project approved in 2021-$150,000	Additional $150,000	

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tibbets Manager, Rates and Regulatory Affairs, Regulatory	Heather Tebbetts Digitally signed by Heather Tebbetts DN: cn=Heather Tebbetts, o=Liberty Utilities, ou=Regulatory, email=heather.tebbetts@libertyutilities.com, c=US Date: 2021.03.19 11:32:29 -04'00'	
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Charles Rodrigues, Director Engineering	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2021.03.19 21:58:34 -04'00'	
State President / Senior VP / VP:	Up to $500,000	Richard Macdonald VP Operations	Richard MacDonald Digitally signed by Richard MacDonald Date: 2021.03.22 11:11:40 -04'00'	
Regional President:	Up to $3,000,000	James Sweeney East Region President		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Change Order Form

2021

Project Overview			
Reason for Change:			
Project ID:	8830-2095	**Project Name:**	Tuscan Village EV Chargers
Change Order Name:	8830-2095 Tuscan Village EV Chargers	**Date Prepared:**	1/18/21
Change Order #:	8830-2095 #2	**Financial Work Order (FWO):**[i]	
Project Sponsor:	Christopher Steele	**Revised Start Date:**	1/1/2020
Project Lead:	Heather Tebbetts	**Revised End Date:**[ii]	12/31/2021
Prepared By:		**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☒ No	**If No is Selected, Please specify source of funds**[iv]	8830-1933 Backup Battery $55K

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$150,000**	**$150,000**	**$54,768**	**$354,768**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount:

The original business case and capital expenditure form provided for two level 2 chargers and two level three chargers to be installed at Tuscan Village. After further discussions with ChargePoint in the spring of 2021, they determined that based on the installations north of Boston and Southern NH, we should install one level 2 charging station and 4 level 3 charging stations to accommodate clustering of stations (two or more together). When drivers are able to find clusters of level 3 stations, they are more utilized than having single charging stations where the single level 3 station may be busy without a second option to charge, thus the driver is looking elsewhere to charge. The Company took the direction from ChargePoint and installed one level 2 charger (with 2 ports) and is in the process of installing 4 level 3 (2 clustered together) chargers within Tuscan Village.
Click here to enter text.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)

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Change Order Form

2021

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Heather Tebbetts	Heather Tebbetts Digitally signed by Heather Tebbetts Date: 2022.01.19 14:34:18 -05'00'	
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000			
Senior Director/Director:	Up to $250,000	Christopher Steele Senior Director, Electric Operations	Christopher Steele Digitally signed by Christopher Steele Date: 2022.02.11 08:07:54 -05'00'	
State President / Senior VP / VP:	Up to $500,000	Neil Proudman NH President		
Regional President:	Up to $3,000,000	James Sweeney East Region President		
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Project Close Out Report 2022

Requesting Region or Group:		**Date of Closeout (MM/DD/YY):**	
Project Name:	Tuscan Village EV Chargers 8830-2095		
Requesting Region:		**Sponsor** (Name)**:**	Charles Rodrigues
Project Champion:	Heather Tebbetts	**Project Champion**	
Project Status	X In Service ☐Complete ☐ Closed		
Project Start Date:		**Project Completion Date:**	
Requested Capital ($)	$460,000	**Expenditure Included in Approved Budget?**	Yes X No

Section 1. Approval

Approval of the Project Closeout and Assessment Report indicates an understanding and formal agreement that the project is ready to be closed. By signing this document, each individual agrees all administrative, financial, and logistical aspects of the project should be concluded, executed, and documented as described herein.

Further, by signing this Report, it is accepted that CWIP (FERC Account 107) should be transferred to Utility in Plant Service (FERC Account 101)

Approver Name	Title	Signature	Date
Heather Tebbetts	Project Lead	Heather Tebbetts Digitally signed by Heather Tebbetts Date: 2023.07.31 16:19:34 -04'00'	
Charles Rodrigues	Project Sponsor	Charles Rodrigues Digitally signed by Charles Rodrigues Date: 2023.08.02 11:40:08 -04'00'	
	Operations Manager		
	Accounting Manager		

Section 2. Final Deliverable/Deployment Checklist

Sponsor to respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question	Response
2.1	Do you agree that the product and/or service is ready to be deployed?	Yes ☐x No ☐
2.2	Do you agree the product and/or service has sufficiently met the stated business goals and objectives?	Yes ☐x No ☐
2.3	Do you fully understand and agree to accept all operational requirements, operational risks, maintenance costs, and other limitations and/or constraints imposed as a result of ongoing operations of the product and/or service?	Yes ☐x No ☐
2.4	Has the final unitization estimate been provided to Property Accounting?	Yes ☐x No ☐

Item	Question	Response
2.5	Do you agree the project should be closed? If no, please explain:	Yes ☐x No ☐
	Scale of 1 thru 5; 5 = highest	
	Rate your level of satisfaction with regards to the project outcomes listed below	
2.5	Project Quality	4/5
2.6	Product and/or Service Performance	4/5
2.7	Scope	5/5
2.8	Cost (Budget)	5/5
2.9	Schedule	3/5

Section 3. Project Documentation Checklist

Project Manager Respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question		Response
3.1	Have project documentation and other items (e.g., Business Case, Project Plan, Charter, Budget Documents, Status Reports) been prepared, collected, filed, and/or disposed?		Yes ☐x No ☐
3.3[i]	Were audits (e.g., project closeout audit) completed and results documented for future reference?		Yes ☐ No ☐
3.4	Identify the storage location for the following project documents items:		
Item	**Document**	**Location (e.g., Google Docs, Webspace)**	**Format**
3.4a	Business Case	Operations Finance website	X☐ Electronic ☐ Manual
3.4b	If available, the Final Project Schedule	N/A	X☐ Electronic ☐ Manual
3.4c	Budget Documentation and Invoices	Regulatory Drive	X☐ Electronic ☐ Manual
3.4d	Status Reports	N/A	☐ Electronic ☐ Manual
3.4e	Risks and Issues Log	N/A	☐ Electronic ☐ Manual
3.4f	Final deliverable	N/A	☐ Electronic ☐ Manual
3.4g	If applicable, verify that final project deliverable for the project is attached or storage location is identified in 3.4.		

Section 4. Project Team [ii]

Project Manager to list resources specified in the Project Plan and used by the project.

Name	Role	Type (e.g., Contractor, Employee)
Heather Tebbetts	Project Manager	Employee

Section 5. Project Lessons Learned

Project Team to identify lessons learned specifically for the project. State the lessons learned in terms of a problem (issue).If available please include a Lesson Learned Log in the attached.. Please summarize the top three issues on the project and the recommended improvements to correct a similar problem in the future.

Problem Statement	Problem Description	References	Recommendation
Permitting issues with town	Town refused to give building permit and delayed installation by over 6 months		In person meetings, email with receipt permits and any other documentation to ensure it's not "lost" by the town

Section 7. Open Issues

Project Manager and Functional Lead to describe any open issues and plans for resolution within the context of project closeout. Include an open issue for any "no" responses in the Final Product and/or Service Acceptance Checklist and the Project Artifacts Checklist sections.

Issue	Planned Resolution

Section 8. Project Cost Summary

Project Manager and Functional Lead to provide details for the following tables.

Cost Category	1- Budget	2- Actual	3 = 1 -2 Variance

Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$460,000	$ 417,173	$42,827

Reasons for Variance	**Impact**
Change order #1 2021	$150,000
	$
	$

Budget Approved	**Impact**
2020	$210,000
2021	$150,000
2022	$100,000

Project Manager to list of all work orders associated with project that should be closed once Close Out Report is accepted.

Registry of All Job Codes (Regional, Corporate, LABs)

[i] This section assumes an accounting audit has been completed ensuring all outstanding payments have been reconciled to the project
[ii] For Section 4 in filling out the Project Team Section, for those projects following the materiality limit set forth in the work order approval limits greater than $5M please complete this section, all other projects do not require this.

Capital Approval form

Capital Approval:	DNH.0000816_2022.001	Capital Approval Status	Approved
Year:	2022	Date Prepared:	Nov 7, 2022
Funding:	Full Funding	Prepared by:	Ryan Patnode

Header

Item Name:	IEEE 5 Year Software Subscription	Item ID:	DNH.0000816.001
Item Type:	Capital Project	Bucket Name:	Discretionary-Other
Company Name:	LU Granite State Electric	State:	NH - New Hampshire
Project type:	Discretionary	Mandated:	No
Asset Type:	Intangible Plant	Asset Class:	3032-Miscellaneous intangible plant 5YR
Useful Life (Yrs):	05	Regulatory Mechanism supported ?:	N
Budget Number:	3071-SPECIFIC SPEC-Speci	Project Lead:	Melvin Emerson
Planned or unplanned ?:	Unplanned	Project Sponsor:	Anthony Strabone
Project Start Date:	Nov 7, 2022	Project End Date:	Dec 30, 2022
Initial Capital Estimate:	155,000	Initial Expense Estimate:	0
		Initial Total Estimate:	155,000
Current Req Capital Cost:	155,000	Current Req Expense Cost:	0
		Current Req Total Cost:	155,000
Prior approved Cap Cost:	0	Prior approved Exp Cost:	0
		Prior approved Total Cost:	0
All values in:	USD		

Project Objectives

Project Scope Statement:	IEEE houses an unrivaled network of professionals, experts, and advisors that can help shape your career, offer resources to acquire new skills, advance your professional development, and provide numerous opportunities for involvement, recognition, and reward.
Background:	Approximately 9,600 + IEEE standards documents in topics covering power and energy, telecommunications, LAN/MAN, information technology, software, electromagnetic compatibility, and more.
Recommendation/ Objective:	To gain 5 year subscription to draft and archived standards, along with IEEE Xplore digital library.
Permitting requirements / Environmental Impacts:	N/A
Removal Expenditure Involved ?:	N/A
Alternatives/ Options:	Alternative 1 - Do nothing (see risk) Alternative 2 - 3 year subscription (see risk)
Schedule:	5 year subscription all purchased in 2022.
Risk Assessment:	Doing nothing would have ended the subscription to IEEE. 3 year subscription was set at $92,985. This price was subject to annual price increase which are usually between 3% to 5% every year.
Trade Finance:	8830-2201 - GSE Storm program. Asking for $155,000.
Health,Safety and Security concerns and impacts:	This project will adhere to all Liberty Utilities Health, Safety & Security procedures.

Supporting Documentation / Other Pertinent Details	Reference attached email from vendor.

Capital Approval form

Financials

Next Anticipated Test Year:

Incl in Approved Budget: No

Regulatory Lag: <6 Months

IRR: 0

Estimate Basis: External/Other

Fin Supporting Info (Reg Construct/Estimate Basis): Reference attached email from vendor

All values in: USD

Financials	Y1	Y2	Y3	Y4	Y5
Internal Labor	0	0	0	0	0
External Labor	0	0	0	0	0
Materials (Incl Taxes)	0	0	0	0	0
Vehicles / Tools	0	0	0	0	0
Overheads	0	0	0	0	
AFUDC	0	0	0		
Other	155,000	0	0		
O&M Costs	0	0	0		
Total	155,000	0	0		

Capital Approval form

Approval Log

Approver Title	Approval Authority Limit	Approver ID	Approver Name	Approval Date	Decision	Comments
Accounting		RPATNODE	Ryan Patnode	Nov 8, 2022	Approved	PPM set up approved.
Manager	Up to 100000.00	MEMERSON	Melvin Emerson	Nov 15, 2022	Approved	Reviewed & Approved 11/15/22
Senior Manager	Up to 200000.00	ASTRABONE	Anthony Strabone	Nov 17, 2022	Approved	Approved

Liberty Utilities
WATER | GAS | ELECTRIC

Change Order Form

2022

Project Overview			
Reason for Change: Initial estimate/budget did not include burden cost only direct cost.			
Project ID:	DNH.0000816	**Project Name:**	IEEE-Membership
Change Order Name:	DNH.0000816 IEEE-Membership	**Date Prepared:**	8/3/2023
Change Order #:		**Financial Work Order (FWO):**[i]	
Project Sponsor:	Anthony Strabone	**Revised Start Date:**	11/1/2022
Project Lead:	Kedrick Robinson	**Revised End Date:**[ii]	12/31/2022
Prepared By:	Ryan Patnode	**Change Type**[iii]	x In Scope ☐ Out of Scope
Project Contingency Available?	☐ Yes ☒ No	**If No is Selected, Please specify source of funds**[iv]	

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Category	Original Project Value (2021)	Previous Approved Charges	Current Change Order Amount	Total
Internal Labor				
Materials				
Equipment				
Contractor/Subcontractor				
Burdens/Overheads				
AFUDC				
Total Project Cost	**$155,000**		**$53,000**	**$208,000**

Updated Unlevered Internal Rate of Return:

Basis of Current Change Order Amount: Initial estimate/budget did not include burden cost only direct cost.

Schedule Impacts
(As a result of the Change Order, where applicable, List the Impacts to schedule)

Baseline Schedule (BL)	New Forecast (NF)	Variance (BL – NF)

Approvals and Signatures[v]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $10,000			
Senior Manager	Up to $200,000	Kedrick Robinson Manager, Engineering Projects	Kedrick Robinson	8/3/2023
Senior Director/Director:	Up to $500,000			
State President / Senior VP / VP:	Up to $2,000,000	Neil Proudman, NH President		
Regional President:	Up to $3,000,000			
Corporate - Sr VP Operations:	Up to $5,000,000			
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000			

[i] The Financial Work Order Section captures the work order this change falls under when the job was initially set-up
[ii] The Revised project end date is dependent on changes in scope that may deviate the schedule from the original plan
[iii] The Change type for In scope or Out of scope changes fall within the following scenario:

- In Scope changes are deviations of scope from the original plan and approved budget that align to the original scope of the project but have revised pricing as a result of changes in pricing of labour, materials, and equipment
- Out of Scope changes are scope changes that were not originally planned for in the project baselines and approved budget. Examples of this type of change are related to changes in technology, missed deliverables, a change in the project design altering the scope of the project, etc.

iv In cases where the project no longer has contingency to cover project change orders, please specify any other sources of funds that would address the project variance (i.e. not executing another project, delaying scope of another project, etc)

[v] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Project Close Out Report 2022

Requesting Region or Group:	Granite State Electric	**Date of Closeout (MM/DD/YY):**	07/31/2023
Project Name:	IEEE 5 year Software Subscription DNH.0000816		
Requesting Region:	East Region	**Sponsor** (Name)**:**	Anthony Strabone
Project Champion:	Kedrick Robinson	**Project Champion**	Melvin Emerson
Project Status	X In Service ☐Complete ☐ Closed		
Project Start Date:	11/1/2022	**Project Completion Date:**	12/31/202
Requested Capital ($)	$155,000	**Expenditure Included in Approved Budget?**	X Yes ☐No

Section 1. Approval

Approval of the Project Closeout and Assessment Report indicates an understanding and formal agreement that the project is ready to be closed. By signing this document, each individual agrees all administrative, financial, and logistical aspects of the project should be concluded, executed, and documented as described herein.

Further, by signing this Report, it is accepted that CWIP (FERC Account 107) should be transferred to Utility in Plant Service (FERC Account 101)

Approver Name	Title	Signature	Date
Melvin Emerson	Project Lead	Melvin Emerson	7/31/2023
Kedrick Robinson	Manager	Kedrick Robinson	7/31/2023
	Operations Manager		
	Accounting Manager		

Section 2. Final Deliverable/Deployment Checklist

Sponsor to respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question	Response
2.1	Do you agree that the product and/or service is ready to be deployed?	Yes ☒ No ☐
2.2	Do you agree the product and/or service has sufficiently met the stated business goals and objectives?	Yes ☒ No ☐
2.3	Do you fully understand and agree to accept all operational requirements, operational risks, maintenance costs, and other limitations and/or constraints imposed as a result of ongoing operations of the product and/or service?	Yes ☒ No ☐
2.4	Has the final unitization estimate been provided to Property Accounting?	Yes ☒ No ☐

Item	Question	Response
2.5	Do you agree the project should be closed? If no, please explain:	Yes ☒ No ☐
	Scale of 1 thru 5; 5 = highest	
	Rate your level of satisfaction with regards to the project outcomes listed below	
2.5	Project Quality	5/5
2.6	Product and/or Service Performance	5/5
2.7	Scope	5/5
2.8	Cost (Budget)	5/5
2.9	Schedule	5/5

Section 3. Project Documentation Checklist

Project Manager Respond to each question. For each "no" response, include an issue in Open Issues section.

Item	Question		Response
3.1	Have project documentation and other items (e.g., Business Case, Project Plan, Charter, Budget Documents, Status Reports) been prepared, collected, filed, and/or disposed?		Yes ☒ No ☐
3.3[i]	Were audits (e.g., project closeout audit) completed and results documented for future reference?		Yes ☒ No ☐
3.4	Identify the storage location for the following project documents items:		
Item	**Document**	**Location (e.g., Google Docs, Webspace)**	**Format**
3.4a	Business Case	Operations Finance SharePoint	☒ Electronic ☐ Manual
3.4b	If available, the Final Project Schedule	N/A	☐ Electronic ☐ Manual
3.4c	Budget Documentation and Invoices	W:\Public\Accounts Payable\New Hampshire	☒ Electronic ☐ Manual
3.4d	Status Reports	N/A	☐ Electronic ☐ Manual
3.4e	Risks and Issues Log	N/A	☐ Electronic ☐ Manual
3.4f	Final deliverable	N/A	☐ Electronic ☐ Manual
3.4g	If applicable, verify that final project deliverable for the project is attached or storage location is identified in 3.4.		

Section 4. Project Team [ii]

Project Manager to list resources specified in the Project Plan and used by the project.

Name	Role	Type (e.g., Contractor, Employee)
Anthony Strabone	Sr. Director	Employee
Kedrick Robinson	Manager	Employee

Section 5. Project Lessons Learned

Project Team to identify lessons learned specifically for the project. State the lessons learned in terms of a problem (issue).If available please include a Lesson Learned Log in the attached.. Please summarize the top three issues on the project and the recommended improvements to correct a similar problem in the future.

Problem Statement	Problem Description	References	Recommendation
None	None	None	None

Section 7. Open Issues

Project Manager and Functional Lead to describe any open issues and plans for resolution within the context of project closeout. Include an open issue for any "no" responses in the Final Product and/or Service Acceptance Checklist and the Project Artifacts Checklist sections.

Issue	Planned Resolution
None	None

Section 8. Project Cost Summary

Project Manager and Functional Lead to provide details for the following tables.

Cost Category	1- Budget	2- Actual	3 = 1 -2 Variance
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			

External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	$155,000	$ 207,186	($52,186)

Reasons for Variance	**Impact**
Change order #1	$53,000

Project Manager to list of all work orders associated with project that should be closed once Close Out Report is accepted.

Registry of All Job Codes (Regional, Corporate, LABs)

[i] This section assumes an accounting audit has been completed ensuring all outstanding payments have been reconciled to the project
[ii] For Section 4 in filling out the Project Team Section, for those projects following the materiality limit set forth in the work order approval limits greater than $5M please complete this section, all other projects do not require this.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Data Requests - Set 9

Date Request Received: 9/22/23
Request No: DOE 9-12

Date of Response: 10/6/23
Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-1, Attachment 23-039 3-1.4, 2022 Capital Projects, IEEE-Membership.

a. Please explain why this subscription cost is not an O&M expense. What differentiates this subscription/membership from the others that Liberty subscribes to?

b. Please explain why it was appropriate to assign the burden cost of $53,000 to this expenditure? What is the $53,000 amount based on?

RESPONSE:

a. The subscription/membership spans five years, bringing the asset threshold over the one-year useful life for capital expenses, and a majority of the work related to the subscription will be capital work. The project expenditure is a five-year subscription to an extensive list of industry standards the Company can reference when developing or revising its design, operating, and maintenance standards.

b. The $53,000 was estimated for indirect overheads. Indirect overheads are the expenses that do not have direct cost causation to a project but are costs applied to capital expenditures.

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Business Case

2022

NOTE: This form is required for planned Growth, Regulatory Supported, and Discretionary projects as well as combined blanket projects for Safety and Mandated with Growth, Regulatory Supported, and Discretionary Projects with a spend greater than $100,000 and all unplanned projects. All other Project types can utilize the Capital Expenditure Application Form.

Project Overview			
Project Name:	Granite State Electric AMI	**Date Prepared:**	1/12/2022
Project ID#:	TBD	**Cost Estimate (2022):**	$1,429,800
Project Sponsor:	Christopher Steele	**Project Start Date:**	02/03/2022
Project Lead:	Shawn Furey	**Project End Date:**	12/31/2025
Prepared By:	Shawn Furey	**Planned or Unplanned Projects:**	☐ Planned ☐Unplanned
Project Type (click appropriate boxes):	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		
Spending Rationale:	☐ Growth ☒ Improvement ☐ Replenishment		

Project Scope Statement

(Insert the scope of work, major deliverables, assumptions, and constraints)

In 2020, Granite State Electric partnered with CMG Consulting to review its current electric distribution system in New Hampshire and develop a plan to modernize its grid to help combat many of the issues facing the industry today such as climate change. The Grid Modernization Plan outlined 4 key areas of focus such as metering, distribution automation, customer connections, and smart cities. This business case focuses on one component of the plan which is Advanced Metering Infrastructure (AMI). Currently the company utilizes Automated Meter Reading (AMR) technology; often referred to as one-way communication meters. AMR Meters send a signal and require team members to drive by to collect customer meter consumption data. AMI is different from AMR as a communication network installed along with a two-way meter allow customer meter information to automatically collect and transmit consumption data to the Utility constantly. The metering and communication network work together to construct the foundation of the grid modernization plan.

To determine if AMI was the right technology for Granite State Electric (GSE) and its customers, the company took part in a feasibility study in the summer and fall of 2021. A cost benefit analysis was conducted assuming ITRON OpenWay Riva was the AMI solution. The ITRON OpenWay Riva solution was agreed to under contract between Liberty and ITRON in 2019. Initial Capital costs were estimated in 2019 at approximately $9M for Granite State Electric. The Team at Granite State Electric undertook the opportunity to revise the cost estimate and determined that the capital costs had increased to $18.3M.

With the revised cost estimate given current business case benefits, the current Open Way Riva solution no longer provided GSE customers overall benefit as part of the Grid Modernization plan.

However, the team at GSE and Liberty Utilities met with Itron to determine if other solutions could be feasible at GSE while continuing to provide Liberty Utilities with an ITRON metering solution.

Working together with ITRON, the team at GSE was made aware of a newer solution not available to Liberty Utilities at the time of initial contract which is named GenX. The GenX solution is different from the Open Way solution in its communication network. The GenX communication network allows for other devices in addition to ITRON's current meter to leverage the installation of the communication network.

By allowing other devices to connect to a secure communication network, GSE has identified the GenX network as its foundational communication network with which to construct its Grid Modernization Strategy with.

When factoring in the ability to use the GenX network as the foundation of GSE's Grid Modernization strategy, the team has demonstrated in Table 1 the associated benefits of GenX over Open Way Riva and how the GenX solution is the best solution for its customers and GSE's shareholders.

Table 1 Recommendation Option Summary (20 years)

Options	Nominal Benefit	PV Benefit	IRR
Open Way Riva	$1,898,723	($7,715,689)	0.86%
GenX	$49,478,423	$7,118,280	10.83%

The Team at GSE is recommending proceeding forward with completing the appropriate steps with ITRON to implement the ITRON GenX solution in New Hampshire at GSE.

The estimated required capital for the GenX option by year is shown is table 2 below.

Table 2. Estimated Required Capital

Year	Capital ($)	Notes
2022*	1,429,800	• Itron Contract Revision • Itron Notice to Proceed • Headend Re-design • CGR Itron analysis

2023**	3,376,941	• SAP and AMI design
		• Engineering CGR
		• Procurement
		  ○ CGR's
		  ○ Meters
		• Regulatory Waivers
		• Customer outreach
		• Secure storage facility
		• Electrician Contract setup

2024	14,715,343	• Training for Contractors • Receive materials • Field Deployment
2025	233,433	• Field Deployment • Project Closeout
Total ***	19,755,517	

**The actual capital spent in 2022 will be determined by the timeliness of Itron to deliver revised pricing and an updated contract to Liberty. Capital may be shifted to future budget years to account for delays.*
***Recommend starting detailed work in 2023 and once SAP rollout is complete.*
****Includes 1M of estimated direct capital IT work required to support GenX solution*

Background

(Insert description of current operational arrangement, and brief history of project & asset)

See project scope above

Recommendation/Objective (Insert the unique problem this project is looking to resolve)

Enable Liberty's grid modernization plan.

Alternatives/Options

(Describe all reasonably viable alternatives. Discuss the viability of each and provide reasons if rejected)

As discussed, three options were considered with moving to GenX being the option most beneficial for the customer and the company.

Financial Assessment/Cost Estimates
(Double click embedded excel file to update; include contingency allowance in excel file)

Next Anticipated Test Year	**1/1/2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No

Regulatory Lag
(Click appropriate box) ☐Less than 6 Months ☐6-12 Months ☐1 to 3 years ☒Greater than 3 years

Category	Total Already Approved	2022	2023	Beyond 2023	Total
Internal Labor					
Materials					
Equipment					
Contractor/ Subcontractor					
AFUDC					
Total Project Cost ($)		**1,429,800**	**3,376,941**	**14,948,777**	**19,755,517**

Unlevered Internal Rate of Return: 10.83% (over 20 years)

Basis of Estimate: *Internal estimate*

For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:

Schedule
(List key milestone dates)

Key Milestone Description	Forecast Start Date	Forecast End Date
See table 2 in project scope section		

Risk Assessment
(Please describe the risk of not completing the project)

If project does not proceed then Granite States grid modernization plan cannot be fully developed.

Trade Finance (Is there a possibility to apply trade finance products to this project? See Capital Planning for further clarification)
N/A
Supporting Documentation (Reference drawings, condition assessment reports, vendor quotations, etc. Attach document or where possible include hyperlink to file located on shared server or SharePoint)
See appendix for supporting business case report.

Approvals and Signatures[i]

Approved By:				
Role	**Approval Authority Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Shawn Furey		1/27/2022
Senior Manager: :	Up to $50,000			
Senior Director/Director:	Up to $250,000	Christopher Steele		
Senior Vice President/ Vice President	Up to $500,000			
State President:	Up to $500,000	Neil Proudman	Neil Proudman Digitally signed by Neil Proudman Date: 2022.01.27 12:39:18 -05'00'	
Regional President:	Up to $3,000,000	James Sweeney		
Corporate - Sr VP Operations:	Up to $5,000,000	Gerald Trembley		
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston		

[i] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Capital Project Expenditure Form 2022

Project Name:	Granite State Electric AMI		
Financial Work Order (FWO):	TBD	**Project ID #:**	TBD
Requesting Region or Group:	Granite State Electric	**Date of Request (MM/DD/YY):**	1/12/2022
Project Sponsor:	Christopher Steele	**Project Start Date:**	2/3/2022
Project Lead:	Shawn Furey	**Project End Date:**	12/31/2025
Prepared by:	Shawn Furey	**Requested Capital ($) (2022)**	$1,429,800
Planned or Unplanned Projects:	☒ Planned ☐Unplanned		
Project Type: (Click appropriate boxes)	☐ Safety ☐ Mandated ☐ Growth ☒ Regulatory Supported ☐ Discretionary		

Details of Request

Project description
In 2020, Granite State Electric partnered with CMG Consulting to review its current electric distribution system in New Hampshire and develop a plan to modernize its grid to help combat many of the issues facing the industry today such as climate change. The Grid Modernization Plan outlined 4 key areas of focus such as metering, distribution automation, customer connections, and smart cities. This business case focuses on one component of the plan which is Advanced Metering Infrastructure (AMI). Currently the company utilizes Automated Meter Reading (AMR) technology; often referred to as one-way communication meters. AMR Meters send a signal and require team members to drive by to collect customer meter consumption data. AMI is different from AMR as a communication network installed along with a two-way meter allow customer meter information to automatically collect and transmit consumption data to the Utility constantly. The metering and communication network work together to construct the foundation of the grid modernization plan. To determine if AMI was the right technology for Granite State Electric (GSE) and its customers, the company took part in a feasibility study in the summer and fall of 2021. A cost benefit analysis was conducted assuming ITRON OpenWay Riva was the AMI solution. The ITRON OpenWay Riva solution was agreed to under contract between Liberty and ITRON in 2019. Initial Capital costs were estimated in 2019 at approximately $9M for Granite State Electric. The Team at Granite State Electric undertook the opportunity to revise the cost estimate and determined that the capital costs had increased to $18.3M. With the revised cost estimate given current business case benefits, the current Open Way Riva solution no longer provided GSE customers overall benefit as part of the Grid Modernization plan.

However, the team at GSE and Liberty Utilities met with Itron to determine if other solutions could be feasible at GSE while continuing to provide Liberty Utilities with an ITRON metering solution.

Working together with ITRON, the team at GSE was made aware of a newer solution not available to Liberty Utilities at the time of initial contract which is named GenX. The GenX solution is different from the Open Way solution in its communication network. The GenX communication network allows for other devices in addition to ITRON's current meter to leverage the installation of the communication network.

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When factoring in the ability to use the GenX network as the foundation of GSE's Grid Modernization strategy, the team has demonstrated in Table 1 the associated benefits of GenX over Open Way Riva and how the GenX solution is the best solution for its customers and GSE's shareholders.

Table 1 Recommendation Option Summary (20 years)

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Open Way	$1,898,723	($7,715,689)	0.86%
GenX	$49,478,423	$7,118,280	10.83%

The Team at GSE is recommending proceeding forward with completing the appropriate steps with ITRON to implement the ITRON GenX solution in New Hampshire at GSE.

Liberty Utilities
WATER | GAS | ELECTRIC

Capital Project Expenditure Form 2022

The estimated required capital for the GenX solution by year is shown is table 2 below.

Table 2. Estimated Required Capital

Year	Capital ($)	Notes
2022*	1,429,800	• Itron Contract Revision • Itron Notice to Proceed • Headend Re-design • CGR Itron analysis

2023**	3,376,941	• SAP and AMI design
		• Engineering CGR
		• Procurement
		  ○ CGR's
		  ○ Meters
		• Regulatory Waivers
		• Customer outreach
		• Secure storage facility
		• Electrician Contract setup

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Total ***	19,755,517	

**The actual capital spent in 2022 will be determined by the timeliness of Itron to deliver revised pricing and an updated contract to Liberty. Capital may be shifted to future budget years to account for delays.*
***Recommend starting detailed work in 2023 and once SAP rollout is complete.*
****Includes 1M of estimated direct capital IT work required to support GenX solution*

`

Is this project growth or customer connection related? If "yes", list the specific locations and how expenditure aligns with customer expansion objectives.

No

Liberty Utilities WATER | GAS | ELECTRIC

Capital Project Expenditure Form 2022

Please describe any permitting requirements, environmental impacts, or resulting performance obligations that may or may not result from this expenditure?
Not moving forward with AMI and GenX would limit Granite State's grid modernization efforts.

Will there be assets, greater than $5,000, currently in service removed as a result of this expenditure?
GUIDANCE: If yes, please detail the specific assets that will be removed: 1. *Original Cost of Plant to be removed (if known):* 2. *What is the replacement cost of the plant being removed (if original cost not known)?* 3. *Original Work Order of Plant to be removed (if known):* 4. *Is the Plant being removed reusable?* 5. *What is the year of original installation of the plant being removed*

What alternatives were evaluated and why were they rejected?
Three options were considered. See the "project description" section of this document.

What are the risks and consequences of not approving this expenditure?
Not being able to move forward with Granite States grid modernization plan.

Please describe how Health, Safety and Security concerns and impacts as a result of this expenditure been addressed.
N/A

Are there other pertinent details that may affect the decision-making process?
See the "project description" section of this document.

Capital Project Expenditure Form 2022

Complete the Financial Summary table only if:
- **Project is less than $100,000; or**
- **Project category is *Mandated* or *Safety* (Business Case Form not required)**

Financial Summary

Next Anticipated Test Year	**2022**	**Was this Capital Project included in the current year's Board Approved Budget?**	☐ Yes ☒ No
Regulatory Lag (Click appropriate box)	☐ Less than 6 months ☐6 – 12 months ☐1 – 3 years ☒Greater than three years		
Which regulatory constructs will be used for recovering this capital spend?	Rate case will be utilized for capital spend recovery.		
Please Specify Basis of Estimate For materials, equipment, and construction requiring Engineering drawings please specify the percent complete:[i]	☐Fixed or Firm Price ☒Estimate – Internal ☐Estimate – External ☐Other (specify details) Click here to enter text.		
Category	**Current Year**	**Future Years**	Authorized Amount (to be filled in by Corporate)
Cost of Design & Engineering ($)			
Cost of Materials ($)			
Cost of Construction ($)			
External Costs ($)			
Internal Costs ($)			
Other ($)			
AFUDC ($)			
Total Project Costs ($)	1,429,800	18,325,717	

Capital Project Expenditure Form 2022

Approvals and Signatures[ii]

Approved By:				
Role	**Approval Limit**	**Name**	**Signature**	**Date**
Manager / Staff (requisitioner/buyer):	Up to $25,000	Shawn Furey		January 27, 2021
Senior Manager:	Up to $50,000			Click here to enter a date.
Senior Director/Director:	Up to $250,000	Christopher Steele		Click here to enter a date.
Senior VP/VP:	Up to $500,000			
State President:	Up to $500,000	Neil Proudman	Neil Proudman Digitally signed by Neil Proudman Date: 2022.01.27 12:40:01 -05'00'	Click here to enter a date.
Regional President:	Up to $3,000,000	James Sweeney		Click here to enter a date.
Corporate – Sr. VP Operations:	Up to $5,000,000	Gerald Tremblay		Click here to enter a date.
Corporate - Exec Team Member (CEO, CFO, COO, Vice Chair):	Over $5,000,000	Johnny Johnston		Click here to enter a date.

[i] For Best Practices on estimating project contingencies please see the Capital Policy.

[ii] Approvals for work orders and purchase orders are subject to the limits set forth in the Approval Limits of Authority Policy owned and amended from time to time by the corporate procurement group.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

Office of the Consumer Advocate - Set 1

Date Request Received: 7/27/23
Request No. OCA 1-79

Date of Response: 8/10/23
Respondent: Dmitry Balashov
Anthony Strabone

REQUEST:

Did the Company conduct a cost/benefit analysis for its proposed AMI project? If yes, please provide a copy of the analysis in Excel with all formulae intact. If no, please explain why not.

RESPONSE:

Yes, the company conducted a cost-benefit analysis for the AMI project. Importantly, given that the AMI project is first and foremost an asset lifecycle renewal project, the Company was not seeking a particular benefit-to-cost ratio or net present value threshold to proceed with the project. Rather, the Company's goal in conducting a cost-benefit analysis was to determine a conservative scope (and ensuing magnitude) of benefits that it could incorporate into its broader operations planning. Please see Confidential Attachment 23-039 OCA 1-79.xlsx for the requested analysis.

Confidential Attachment 23-039 OCA 1-79.xlsx contains third-party pricing information that is "confidential, commercial, or financial information" protected from disclosure by RSA 91-A:5, IV, that would cause the third-party competitive harm and may cause the Company and its customers economic harm if disclosed. Therefore, pursuant to Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion confirming confidential treatment prior to the final hearing in this docket

Because the confidential information is embedded throughout the Excel workbook, it is not feasible to prepare a redacted version. Thus, only a confidential version of this attachment will be provided.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23 | Date of Response: 11/20/23
Request No: DOE TS 2-39 | Respondent: Dmitry Balashov

REQUEST:

Reference DOE 3-1, 2022 Capital Projects, Granite State AMI, Business Case dated January 12, 2022; DOE 3-3 and DOE 9-8:

a. The budget for this project has dramatically increased from $9 million, to $19.7 million, to $40 million. Itron vaguely attributes the increase to changes in the technology and production costs. Has Itron provided Liberty with a more specific explanation to justify the latest cost increase? What increased capabilities and utility will Liberty obtain from the additional $20 million investment?

b. Please provide all documentation supporting the new $40 million estimate, including a cost breakdown of each of the components that comprise the project.

c. What impact did this cost increase have on Liberty's cost/benefit analysis? Please provide a detailed cost/benefit analysis for the $40 million cost estimate.

d. Reference DOE 3-1, Attachment 2022 DOE 3-1-4, Project 8830-2285, Capital Project Expenditure Form dated 1/12/2022 and Capital Project Business Case dated 1/12/2022: Please provide updates to Tables 1 and 2 found on pages 2 and 3 of each of the referenced documents.

e. Please provide the expected cost savings mentioned in the May 5, 2023, Balashov & Strabone testimony, Bates II-660 and Bates II-661, referencing "capital cost synergies" associated with the IEE Meter Data Management system.

f. What other AMI providers, aside from Itron, did Liberty consider? If other providers were considered, please explain why they were not selected.

RESPONSE:

a. The three estimate figures listed are not comparable, and as such cannot be viewed as budgetary increases of the same project:

    i. The $9 million figure reflects an early working estimate based on Itron's 2019 quote for OpenWay Riva system deployment. The estimate derived from the quote did not have the benefit of holistic planning review across all necessary cost categories. As a result, it did not properly account for internal local and corporate labor required to deliver the project, along with system integration and testing provider costs, applicable overheads, and contingencies for a project of this size and complexity.

ii. The $19.7 million estimate reflects the same starting point (a 2019 Itron quote for the OpenWay Riva system), but factors in all project elements in addition to equipment and labor supplied by Itron, including all cost categories listed in the previous bullet. As such, it is inappropriate to compare the $9 million and the $19.7 million figures, as only the latter represents a realistic cost estimate for an AMI deployment project.

iii. The $40 million estimate is based on a 2023 Itron quote for a GenX technology deployment, which also reflects all applicable cost categories beyond Itron's labor and equipment. Since the Company never entered into a final order agreement with Itron in 2019, the 2023 estimate represents a completely separate undertaking – reflecting a fundamentally different technology than OpenWay Riva, along with changing costs of provision of professional services, installation, and project financing.

While the cost estimates cannot be compared, part (c) of this response demonstrates that the GenX system provides a substantially larger scope of benefits than the OpenWay Riva system. This is largely due to a superior telecommunication protocol of the GenX system, which enables Itron to provide a suite of additional offerings, such as those discussed in Messrs. Balashov and Strabone's testimony. Liberty Granite State also notes that Itron no longer offers installations of OpenWay Riva systems to new customers and will phase out sales of key network components for this system by 2026.

b. Please refer to Confidential Attachment 23-039 DOE TS 2-39.1 that accounts for $13.64 million of the project's estimated costs. The remaining cost categories and the associated amounts are captured in the table below:

Cost Category	Estimated Amount
Itron hardware, professional deployment, and installation services.	$13.64M
Test and Production Environments Set-up	$2.27M
Liberty Staff Costs (Local and Corporate)	$3.90M
External System Integration and Testing Support	$1.78M
Overhead Burden	$9.86M
30% Contingency	$9.4M
Total Estimated Project Cost + Contingency	$40M

**Numbers not additive due to rounding.*

c. Liberty Granite State notes that the requested cost/benefit analysis has been provided in response to OCA 1-79. The Company notes further that the change from OpenWay Riva to GenX technology resulted in a $23.7 million /198% increase in the present value of anticipated benefits relative to the OpenWay scenario. On a Benefit-to-Cost (B/C) basis, the change from OpenWay to GenX technology resulted in an increase of cB/C ratio from 0.60 to 0.79.

d. Liberty Granite State is not able to provide updates to these tables, as doing this would require an update of the overall Business Case, which will only take place after there is clarity about the project's funding status.

e. Based on the consultations with the vendor, the Company estimates that absent the existing functioning IEE MDM system at Empire, the cost of a Liberty Granite State AMI deployment would be $2 million higher in the vendor's professional services, plus approximately $1 million in system integration and testing costs, along with the applicable additional time from internal staff and associated overheads that cannot be reliably estimated at this time.

f. As stated on p. 22 of Messrs. Balashov and Strabone's testimony, Itron was selected by Liberty Granite State's parent company in 2019 as a corporate-wide partner, but in 2022 Liberty Granite State and its affiliate retained Util-Assist Inc to confirm whether Itron remained an industry leader. Please refer to Confidential Attachment 23-039 DOE TS 2-39.2 for the independent consultant's comments on this matter.

Confidential Attachment 23-039 DOE TS 2-39.1 contains the estimated costs for the Itron meters and related services, which information is protected from disclosure by RSA 91-A:5, IV, as "confidential, commercial, or financial information" of a third party. Itron provided this estimate to Liberty under the terms of a non-disclosure agreement which requires the Company to maintain its confidentiality. Therefore, pursuant to that statute and Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion seeking confidential treatment prior to the final hearing in this docket. A redacted version will not be provided as nearly all of the information is confidential.

Confidential Attachment 23-039 DOE TS 2-39.2 is a third party's assessment of Itron and its metering products and services as compared to its competitors. It contains sensitive market information that, if disclosed, could compromise Liberty's bargaining position in relation to Itron and potentially the other vendors discussed. The report is thus protected from disclosure by RSA 91-A:5, IV, as "confidential, commercial, or financial information" of a third party. Therefore, pursuant to that statute and Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion seeking confidential treatment prior to the final hearing in this docket. A redacted version will not be provided as the entire report is confidential.

4 Key Factors to a Successful AMI Project Rollout

Written by Marketing on September 29, 2020

Aclara Website: 4 Key Factors to a Successful AMI Project Rollout | Aclara Blog (hubbell.com)

Sometimes, the key to the success of an advanced metering infrastructure project is not the technology, but project management and implementation. The way an implementation is conducted can make all the difference in the world in terms of meeting success factors of performance, budget, and schedule.

Typically, AMI projects are more challenging than most utility projects because they involve multiple technologies including meters, network equipment, and software. Many times these critical elements come from different vendors. What's more, project management services, as well as implementation services, may be provided by different companies.

According to FERC, "the total capital costs of deploying AMI include the hardware and software costs (meter modules, network infrastructure, and network management software for the AMI system), as well as installation costs, meter data management, project management, and information technology integration costs."

If the implementation costs related to project management and installation are out of control, the success of an AMI project is in jeopardy.

The consulting firm McKinsey and Company offers insight into the requirements for a successful implementation in a white paper, *Best Practices in the Deployment of Smart Grid Technologies*. The report describes the steps that utilities should take to avoid false starts, cost overruns, and subpar results.

"The first stage of a smart grid rollout is generally in the deployment of smart meter technology. Here the record of companies has been mixed – unsurprising given the level of complexity involved," states the report.

Starting with a strong business case and employing lean business operations and change management are a must. The paper also identifies four factors that should guide smart grid implementations:

1. Set up the architecture for implementation

Utilities must determine whether it will act as the prime contractor, how many vendor contracts will be required, which contractors will perform tasks on the project and how much risk they can manage.

2. Select technologies for the long-term and use pilots

Utilities should look to use proven technologies that conform to industry standards and will not become obsolete. Pilots should demonstrate the technical feasibility of vendor solutions and validate cost and benefit assumptions in the business case.

3. Use strategic sourcing to optimize providers' capabilities

Utilities must do as much as possible to minimize risks to ensure that vendors can deliver on their timelines and volumes as outlined in contracts.

4. Maintain a significant business focus on IT integration.

Utilities must focus project management on critical path activities, stage implementations properly, and carefully map automation appropriate for each process step in a test-and-learn approach to reduce the chances of cost overruns.

Every step of the implementation process is fraught with risks, but using workforce management software can significantly reduce those risks.

Aclara's unique workforce management software brings the field into the office, providing product status visibility in real-time, at all times. By providing real-time updates, any issues arising in the field are addressed immediately, before they become problems. Safety and efficiency goals are achieved proactively.

The system's open architecture integrates with existing enterprise systems. We estimate that ProField® mobile workforce yields 50 plus percent higher productivity and 20 times more accurate field data — creating unprecedented value for electric, water, and gas utilities. Read more about Aclara's electric rollouts at Con Ed here.

Keys components of the solution are:

- An OpsCenter collaborative workspace to manage projects in real-time.
- A safety management system that handles safety meetings and reports from handheld devices.
- A call center that manages communications between the utility, its customers, and the deployment company.
- A cascading inventory system that ensures utilities know the location of all assets at all times.
- A training and certification module to ensure all employees are fully trained and certified.
- Real-time observation of the work of field technicians to verify the safety and quality of work.
- Optimization of routes for installation crews that take into account factors such as blackout dates and travel times.
- Precise sequencing of work to ensure it is complete and conforms to best practices.

ProField is deployed at electric, gas, and water utilities nationwide, and most recently at DC Water.

AMI Case Study at AEP Ohio: Deployment Lessons Learned in the gridSMART Pilot Project

Presented by:
Steve Deskins – AEP Ohio

gridSMART
From AEP OHIO

gridSMART Project Background

- ARRA Funded DOE Demonstration Project
- Program consists of 6 main initiatives
  - Advanced Meter Infrastructure (AMI)
  - Distribution Automation (DA)
  - Home Area Network (HAN) and Customer Programs
  - DOE Project Enhancements (CES, PHEV)
  - Customer Engagement
  - Business Process Reengineering

AMI Project Background

- Deployment of 110,000 AMI meters
  - DOE funded
- 97 % installed in Jan, Feb & March 2010
  - Remaining 3% installed remainder of 2010
- Additional 22,000 meters installed December 2010
  - Non Doe funded – AEP Ohio capital expenditure
- Vendor Selected – GE with SSN NIC
- I210+C (Gen 16) & KV2C meters
  - 4 channels of interval data (15 min) on I210+C, 6-8 on KV2C (voltage on all meters)
  - Meter registers used for billing
    - KWH &KW & RDC on all single-phase meters
    - Reactive on all Transformer rated meters
  - Sample test 1 I210+C, 100% KV2C
  - Installation contractor CMI
  - Read with Meter Readers until April 2010
  - Remote Connect/Disconnects

AMI Project Background

AMI Head End System

- AEP selected Silver Spring Networks' UIQ application for our AMI solution. Specific components purchased include:
  - UIQ-AMM (Advanced Metering Management) - SSN's base AMI application
  - UIQ-NEM (Network Element Manager)
  - FWU (Firmware Updater)
  - MPC (Meter Program Configurator)
- We elected to license UIQ-ODS (Outage Detection System), as we have an outage management solution in place – GE PowerON
- SSN hosted two environments for AEP (Production and Test) under a SaaS (Software as a Service) agreement, during the implementation phase of the project.
- Full production solution now hosted at AEP's data center. SSN will remotely provide system operations and monitoring (Managed Services agreement).
- Environments include Production, Development, Test and combined Quality Assurance/Disaster recovery
- MDMS – Oracle Loadstar database

AMI Project Lessons Learned

Doing a pilot was a necessary exercise!

- Business process development
- Implement System Administrator early
- Meter install process refinement – Deployment Lessons Learned
- Test installers and verify qualifications early
- Errors will occur during meter change out, know how to detect and fix them
- Develop meter reading process
- Billing accuracy validation
- Customer issue response plan
- Technology verification (Mesh , S/W)
- Customer communications
- Detailed analysis of vendor proposals

Business Process Lessons Learned

- AEP established a Process Re-engineering team which utilized a process patterned after the GE work-out sessions to review and document the new processes that would to be implemented as a result of the new AMI system. To Date the team has documented:
  - 19 AMI Processes
  - 13 DA Processes
  - 24 Consumer Program Processes

- The Process Re-engineering team was established very early on and was quick to engage the team as new issues were identified. The teams were comprised of cross functional employees which allowed AEP to get answers in real time and enabled the team to quickly move forward with the process discussions. The teams were able to identify the changes needed from the back office support allowing the business process to drive the systems instead of vice versa.

Business Process Lessons Learned

- You are drastically changing the meter landscape from Meter Routes with Meter readers to Wireless Interval Reads with Business Analysts sprinkled in with Telecom Experts and New Equipment Maintenance areas.
  - Get buy in from all groups.
    - MRO, IT, Security, Telecom, MDM team, New Business, Operations, Customer Service Reps, Billing, and so on….
  - Meet often to discuss process change real time.
  - Ensure the proper IT resources are in place – Smart Grid projects are IT projects.
  - Build in the proper time in your project schedule – Start early!
    - It will take more time than you expect to change the business and technology processes
  - Think of the customer during every step of the program.
    - Customer communication processes should be over thought and handled with care.
  - When developing these new processes you will run into roadblocks when you will need to create the band aid before the final solution is ready.

Vendor / System Lessons Learned

- Understand your deployment area and the inventory needed to allow for long lead times and 3rd party vendors associated with your products.
- The technology we are dealing with is bleeding edge and maturing as we speak
  - Expect issues to arise
  - We ran into specific firmware issues with the commercial AMI meter and the NIC card
    - This delayed our installation while the vendors fixed and then tested the update.
    - This patch then had to be applied manually to the already installed commercial AMI meters.
- Firmware versioning needs to be tracked closely
  - What works in one territory might not work in the next.
  - We found on our MESH radio system that a level of firmware worked great on a different op co's gridSMART system, but it was not working at the same level of efficiency on the NE Columbus system.
  - Many hours were spent on both sides of the fence testing the MESH network, tweaking and optimizing the final system.
  - It was finally determined that the firmware version was off slightly between the two but not fully documented as such.

Vendor / System Lessons Learned

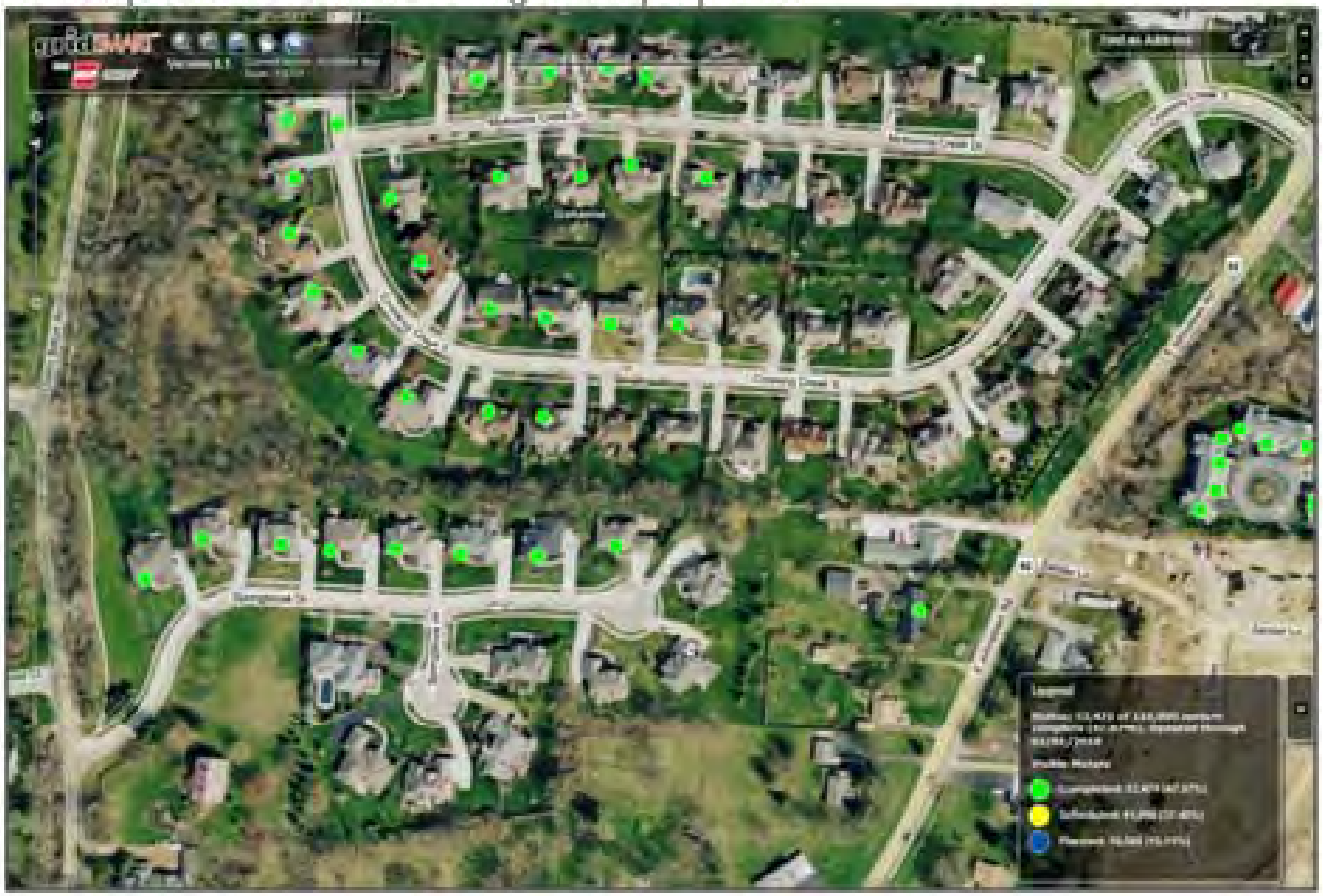
- When putting the new AMI systems in place (Head-End and related modules) have the proper testing plans in place when firmware updates are released.
  - A firmware update to one module can cause problems in other modules or legacy systems.
  - Deadlines are typically driving the project schedule, but try and build this extra time into your schedule.
  - Try to fully understand the risks up front on system firmware upgrades.
    - Don't try to cut corners.
  - A helpful tool / process for AEP working with the vendors is having a collaboration tool with a vendor to track all open tickets and issues.
    - Brings transparency to the issue resolution process
    - Allows other teams from both sides to look at open and existing issues and can help bring out new solution or problems
    - Vendor / Client should each have a single point of contact for overall ownership and project structure.
  - Detailed Release notes can only help in the firmware update process.
  - Collaboration with other utilities helps vet out issues and helps the vendor better understand what the functionality should be.
  - More time on Root Cause should be spent on both sides to help understand why these issues occurred in the first place and how to prevent moving forward.

Vendor / System Lessons Learned

- Understand your new systems and what they are capable of and what they are to actually be used for.
  - Your new head end can provide you valuable information... But do not confuse it for being your system of record. Your CIS and Legacy systems are built for this.
    - AEP has a pilot project of 110k DOE meters
    - AEP also has a smaller project deployment of 22k Non DOE meters
    - These need to be tagged as such in the appropriate legacy systems and the head end is not the entry point for this type of data.
    - This also goes back to the business process re engineering
    - Tracking of all installation activity for each address premise.
  - AEP has seen unreachable meters in the meter management system, the system can not analyze exactly what the exact reason why.
    - As these systems develop further analysis will be provided to help determine the root cause of an unreachable meter.
    - These new systems should be a point of reference on solving the problem and your meter operations group will need to help determine the exact issues – No Service, tampering, firmware issue, telecom, etc.

Deployment Lessons Learned

- Mapping your deployment allows you to visualize your initial deployment and spot unforeseen potential problems.
  - We found installation holes after the installation plan was set and meter installation had begun.
- It is a great communication tool for internal stake holders and can be used with the public
- Can help identify issue customers during the deployment.

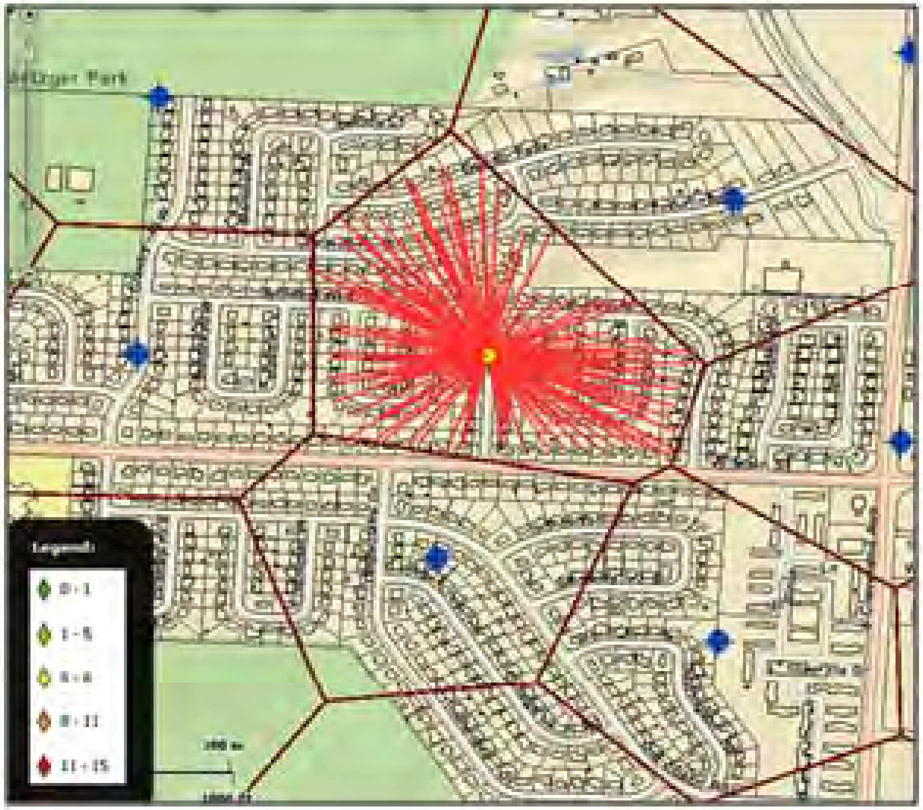


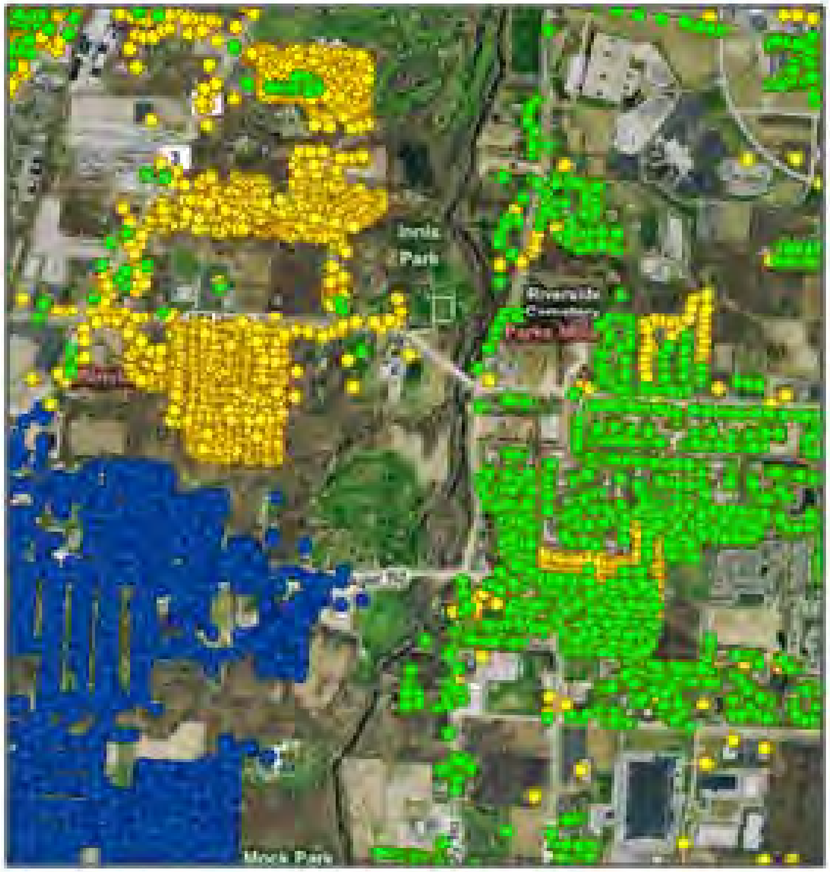
Deployment Lessons Learned

- Taking pictures of the old and new meters is an important step during deployment
  - You can identify miss-reads, tampering, installation issues, etc.
  - A living document of what happened at this premise during the installation
- Something we realized after the fact was taking pictures on strike 3 locations
  - Access issues, meter base problems, cut at weather head, etc.
  - This allows the CSR the ability to better understand the problem rather than looking at a flat file to understand hundreds of premise location issues.
  - This can also be linked to your mapping program

Deployment Lessons Learned

- The NE Columbus project area is a small subset of the Ohio service territory– re defining the meter reading routes had to be done
  - A mapping system can greatly reduce the time by color coating existing cycle / routes.
- Defining the new AMI area into service areas will also need to be defined
  - The mapping system can also break these into "Polygons" to better define these areas and the associated metes and telecom equipment.





Deployment Lessons Learned

Other Success Factors

- Communications
  - Introduction letter
  - Door hangers
  - Blast phone call
  - Website map showing progress
  - Specially trained call center agents and field customer service reps
  - Call Center training for PUCO & OCC
  - Community outreach
- Testing & Verification
  - Pre-installation meter testing
  - Usage Comparison Reports for AMI to non-AMI customers

Any Questions?

Steve Deskins – AEP Ohio: spdeskins@aep.com

gridSMART
From AEP OHIO

Advanced metering infrastructure - A detailed walkthrough.

AMITH VIJAYAN 8,027
ENGINEER, KERALA STATE ELECTRICITY BOARD LTD

Intelligent Utility Network: [Advanced metering infrastructure - A detailed walkthrough. | Energy Central]

A global energy expert and power system engineer with a passion for teaching and research. Sharing knowledge with the world, has spoken at international power conferences, and am an active member...

The Advanced Metering Infrastructure (AMI) combines smart meters, communication networks, and data management systems to create seamless two-way communication between utilities and their customers. This system offers capabilities that were previously not attainable or required manual labor, such as remote and automatic measurement of electricity usage, connection and disconnection of service, detection of tampering, identification and resolution of outages, and voltage monitoring. Additionally, the AMI grants utilities the ability to introduce new time-based rate plans and incentives aimed at encouraging customers to reduce peak demand, manage energy consumption, and keep costs low.

Building Blocks of AMI

The Advanced Metering Infrastructure (AMI) is a comprehensive system of hardware and software components that work together to measure and transfer information on electricity consumption. The primary technological components of AMI include:

Smart Electricity Meters: A Revolution in Energy Management

Smart electricity meters, also known as advanced metering infrastructure (AMI), are a type of digital meter that measures the electricity usage in a home or business in real-time. These meters communicate with the power utility through a wired or wireless network and provide a much more accurate and efficient way to manage energy usage compared to traditional analog meters.

Smart meters offer several benefits to both consumers and power companies. For consumers, smart meters provide real-time information about their energy usage, allowing them to make informed decisions about their energy consumption and save money on their electricity bills. Additionally, smart meters eliminate the need for manual meter readings, which can be inaccurate and time-consuming.

Power companies also benefit from smart meters by having the ability to monitor energy usage and quickly respond to power outages and other issues. This results in improved reliability and quicker resolution times for power-related problems. Smart meters also provide power companies with valuable data that can be used to make informed decisions about energy production and distribution.

One of the key features of smart meters is the ability to remotely disconnect and reconnect service, which eliminates the need for power companies to send technicians to physically disconnect or reconnect service at a customer's home. This not only saves time and resources but also improves safety by reducing the number of technicians required to work in potentially hazardous conditions.

Another key feature of smart meters is the ability to support dynamic pricing, which allows power companies to charge customers different rates based on the time of day and the electricity demand. This type of pricing can help reduce peak demand and encourage customers to shift their energy usage to times when electricity is less expensive.

Communication Network

Communication networks play a crucial role in the functioning of smart meters, providing data transmission capabilities that allow for real-time energy monitoring, improved customer service, automated billing, improved grid management, and increased transparency.

Types of Communication Networks:

- Wired Communication Networks: This type of network uses a physical connection to transmit data between the meter and the energy provider. This can be done through power line communication (PLC), Ethernet, or a similar type of network. The main advantage of wired networks is their reliability, as the data is transmitted directly from the meter to the provider.
- Wireless Communication Networks: Wireless networks transmit data between the meter and the energy provider using radio waves. The most common type of wireless communication network used for smart meters is Zigbee, which operates in the 2.4 GHz frequency band. Other types of wireless networks, such as Wi-Fi or cellular networks, may also be used.
- Hybrid Communication Networks: Hybrid networks combine elements of both wired and wireless communication networks to provide a more comprehensive solution. This can be achieved by using a combination of PLC and Zigbee, for example. The advantage of hybrid networks is that they provide the reliability of wired networks with the convenience and flexibility of wireless networks.

By choosing the right communication network for their needs, energy providers can ensure that their smart meter implementation is successful and provides the benefits that customers and energy providers are looking for.

Meter Data Acquisition System (MDAS)

MDAS is a crucial component in the modern energy management system, responsible for collecting and storing data from various energy meters. The data collected from these meters is then used to calculate the energy consumption and cost of the facilities.

In the traditional meter reading system, meter readers had to manually read and record the readings from each meter. This was a time-consuming and error-prone process. MDAS provides an automated solution to this problem by using advanced communication and data processing technologies.

MDAS consists of three main components: the energy meters, the communication network, and the central data processing system. Energy meters collect data on energy consumption and send it to the communication network. The communication network transmits the data to the central data processing system, where it is stored, analyzed, and processed to provide useful information.

One of the key benefits of MDAS is its accuracy. MDAS eliminates the possibility of human error in meter reading and recording. The system can also perform real-time data collection and processing, providing up-to-date information on energy consumption and cost.

Another advantage of MDAS is that it reduces the need for manual meter reading, freeing up staff resources to focus on other tasks. In addition, the system provides a centralized database of energy consumption data, which can be used for various purposes, such as identifying areas for energy conservation and reducing energy costs.

MDAS also provides enhanced security for energy data. With the increasing concern about energy security and privacy, MDAS provides a secure and reliable system for collecting and storing energy data. The data is protected by encryption and secure communication protocols, ensuring that only authorized personnel have access to the data.

Meter Data Management System: Streamlining Energy Management

The energy industry has seen significant growth in recent years, leading to an increased demand for efficient and reliable meter data management systems. Meter data management systems (MDMS) are designed to collect, store, process, and analyze meter data from various sources, such as smart meters, energy management systems, and billing systems.

Here are some of the key benefits of implementing a Meter Data Management System:

- Improved Accuracy: MDMS utilizes advanced algorithms and statistical methods to validate, clean, and analyze meter data, which ensures greater accuracy and reliability in energy consumption data.
- Real-Time Monitoring: MDMS provides real-time monitoring and visualization of energy consumption, enabling utilities and energy managers to quickly identify and respond to any anomalies or disruptions in energy consumption.
- Automated Billing: By automating the billing process, MDMS eliminates the need for manual data entry, reducing the risk of human error and saving time and resources.
- Enhanced Customer Experience: MDMS provides customers with access to real-time energy consumption data, empowering them to better manage their energy usage and reduce their energy costs.
- Increased Energy Efficiency: By providing accurate and real-time energy consumption data, MDMS enables energy managers to identify and address energy efficiency opportunities, leading to lower energy consumption and reduced costs.
- Improved Data Management: MDMS provides centralized and secure storage of energy consumption data, making it easier for utilities and energy managers to manage and access this critical data.

A Meter Data Management System is an essential tool for utilities and energy managers to improve the accuracy and efficiency of their energy management processes. With the increasing adoption of smart meters and the growing demand for energy management solutions, MDMS is poised to play a critical role in the future of energy management.

Benefits of AMI Implementation

The AMI technology involves the deployment of smart meters that provide real-time data on energy consumption and costs. The followings are the advantages and benefits of AMI:

Operational Advantage

The AMI technology provides numerous operational advantages to utilities, which have led to significant improvements in the overall efficiency and reliability of the power grid. Here are some of the key operational advantages of AMI:

- Real-time data: AMI provides utilities with real-time data on energy consumption, which allows them to respond quickly to changes in demand and power quality issues. This helps to improve the reliability of the power grid and reduce downtime.

- Improved meter reading: With AMI, meter readings are automatically transmitted to the utility company, eliminating the need for a manual meter reading. This saves time and reduces the potential for human error, improving the accuracy of billing and customer satisfaction.
- Improved outage management: AMI enables utilities to quickly detect and resolve outages, reducing the duration and impact of power interruptions. This results in improved reliability for customers and reduced costs for utilities.
- Increased efficiency: With real-time data on energy consumption, utilities can make data-driven decisions to optimize their operations and reduce costs. This results in increased efficiency and improved financial performance.
- Advanced analytics: AMI provides utilities with a wealth of data on energy consumption, which can be analyzed to identify patterns, trends, and opportunities for improvement. This allows utilities to make informed decisions about their operations and improve the overall performance of the power grid.
- Better demand response: AMI provides real-time information on energy consumption, which allows utilities to respond more effectively to changes in demand. This helps to reduce the need for expensive power plants and improves the overall efficiency of the power grid.
- Increased customer engagement: AMI provides customers with real-time information on their energy consumption and costs, empowering them to make informed decisions about their energy usage. This helps to promote energy efficiency and reduce energy waste.

Financial Benefits

An AMI is a modern system of measuring and managing electricity usage that provides numerous financial benefits to both utilities and customers. following are the few impactful financial benefits of AMI:

- Cost savings for utilities: AMI eliminates the need for manual meter readings, reducing the costs associated with the process. In addition, real-time data on energy consumption allows utilities to optimize their operations, reduce waste, and increase efficiency, leading to further cost savings.
- Cost savings for customers: AMI helps utilities to detect and resolve billing errors, which can result in significant cost savings for customers. In addition, time-of-use pricing incentivizes customers to reduce their energy consumption during peak hours, lowering their energy bills.
- Increased revenue for utilities: AMI provides utilities with valuable data on energy consumption, which can be used to identify new revenue opportunities. For example, utilities can offer demand response programs that incentivize customers to reduce their energy consumption during peak hours, generating additional revenue.
- Improved customer satisfaction: AMI provides customers with real-time information on their energy consumption and costs, empowering them to make

informed decisions about their energy usage. This helps to promote energy efficiency and reduce energy waste, leading to improved customer satisfaction.

Customer Advantages

Some of the key customer advantages beyond the above are as follows:

- Improved accuracy of billing: AMI eliminates the need for manual meter readings, reducing the potential for human error and improving the accuracy of billing. This leads to more accurate energy bills and improved customer satisfaction.
- Increased transparency: AMI provides customers with real-time information on their energy consumption and costs, empowering them to make informed decisions about their energy usage. This increased transparency helps customers to understand their energy consumption patterns and identify opportunities for energy savings.
- Increased control over energy usage: With real-time data on energy consumption, customers can make informed decisions about their energy usage, leading to increased energy efficiency and reduced energy waste. This helps to lower energy bills and promote energy sustainability.
- Time-of-use pricing: AMI enables utilities to offer time-of-use pricing, which incentivizes customers to reduce their energy consumption during peak hours. This helps to reduce the need for expensive power plants, lower energy bills, and promote energy sustainability.
- Enhanced security: AMI provides utilities with real-time information on energy consumption, allowing them to quickly detect and respond to potential security threats. This helps to protect customer privacy and data security.

The deployment of AMI provides numerous benefits to both utilities and customers. With improved accuracy, cost savings, increased efficiency, time-of-use pricing, better demand response, and increased customer engagement, AMI is a key enabler of the smart grid and a critical component of the transition to a more sustainable energy future.

Challenges of the AMI implementation

Despite its benefits, the implementation of AMI faces several challenges that must be addressed.

High Capital Costs

One of the biggest challenges of implementing AMI is the high capital costs associated with it. The cost of installing smart meters in millions of homes and businesses can be significant, and it can be difficult for utilities to justify the investment.

The cost of AMI includes the cost of purchasing the smart meters themselves, as well as the cost of installing them in homes and businesses. Additionally, there are costs associated with upgrading the communication networks that transmit data between the meters and the utility's data management systems. The cost of maintenance and repair must also be considered.

Another factor contributing to the high capital costs of AMI is the need for interoperability between different systems. To ensure that the technology works seamlessly, all components must be compatible with each other, including smart meters, communication networks, and data management systems. This requirement can add to the cost of implementation.

Utilities must also consider the cost of training their employees to use the new technology, as well as the cost of any legal or regulatory compliance that may be required. These additional costs can further increase the capital costs of AMI.

The high capital costs of AMI can be a significant barrier to its implementation. Utilities must carefully consider the costs associated with the technology and weigh the potential benefits against the expenses. To minimize the costs, utilities may choose to implement AMI in stages, starting with a pilot program to test the technology before a full-scale implementation. By carefully planning and managing the costs of AMI, utilities can take advantage of the benefits that this technology has to offer.

Interoperability

Interoperability is a crucial aspect of Advanced Metering Infrastructure (AMI) and refers to the ability of different components of the system to work together seamlessly. The success of AMI depends on the interoperability of smart meters, communication networks, and data management systems. Without interoperability, the technology will not function effectively and the benefits it offers cannot be fully realized.

One of the challenges of AMI interoperability is ensuring compatibility between different vendors' equipment. Smart meters and communication networks are typically supplied by different manufacturers, and there is a risk that their products may not be compatible with each other. This can lead to communication issues, data loss, and other problems that can undermine the effectiveness of the AMI system.

Another challenge is the need for standards to ensure interoperability. The absence of standardized protocols for data transmission and management can make it difficult for different components of the AMI system to work together effectively. To achieve interoperability, it is necessary to establish standardized protocols that all components can follow.

To overcome these challenges, utilities must carefully consider the interoperability of the different components of the AMI system when selecting vendors. They should choose vendors that have a proven track record of delivering interoperable products and that are committed to following industry standards. Additionally, utilities can work with vendors to establish protocols and standards that ensure interoperability and allow the AMI system to function effectively.

Data Privacy and Security

Advanced Metering Infrastructure is a technology-based system that is used to measure, collect, and analyze energy consumption data in real-time. It provides a communication network between utility companies and their customers to exchange data related to energy consumption, billing, and other related information. AMI is becoming increasingly popular due to its ability to improve the efficiency of energy distribution, increase customer engagement, and provide utilities with more accurate data to inform their operations.

However, with the increased use of AMI systems, the concern for data privacy and security is also on the rise. As AMI systems collect and store sensitive information about customers, including energy consumption data, it is crucial to ensure that the data is protected from unauthorized access, misuse, and theft. In this blog post, we will discuss the importance of data privacy and security in AMI and what measures can be taken to ensure the protection of sensitive data.

Importance of Data Privacy and Security in AMI

Energy consumption data collected through AMI systems contain sensitive information about customers, including the type and amount of energy they consume, their billing information, and other personal information. This information, if accessed by unauthorized individuals, can be used to commit fraud or identity theft. Furthermore, if this data is not properly secured, it can also be used to target customers with unwanted marketing or other malicious activities.

In addition to protecting the privacy of customers, data security is also crucial for maintaining the integrity of the energy distribution system. Hackers can potentially access and manipulate the energy consumption data to cause disruptions in the energy distribution system, leading to power outages or other significant consequences.

Measures for Ensuring Data Privacy and Security in AMI

To ensure the privacy and security of the sensitive data collected through AMI systems, it is crucial to implement the following measures:

- Encryption: All data transmitted between utility companies and their customers should be encrypted to protect it from unauthorized access. The data should also be encrypted when it is stored on the server to prevent unauthorized access.

- Access Control: Access to the AMI systems should be controlled through the use of secure authentication and authorization methods, such as user credentials, passwords, and biometric authentication.
- Regular Security Audits: Regular security audits should be conducted to identify potential security vulnerabilities and to implement corrective measures to prevent unauthorized access to the data.
- Data Backup and Recovery: A robust data backup and recovery plan should be in place to ensure that the data can be restored in the event of a security breach.
- Employee Training: Employees handling sensitive data should be trained on the importance of data privacy and security, as well as on the proper handling of sensitive data.

As data privacy and security are critical considerations in the implementation of AMI systems. Energy consumption data collected through AMI systems contain sensitive information about customers that, if accessed by unauthorized individuals, can be used for malicious purposes. To ensure the privacy and security of sensitive data, it is crucial to implement measures such as encryption, access control, regular security audits, data backup and recovery, and employee training. By taking these measures, utilities can ensure the protection of sensitive data and maintain the trust of their customers.

Public acceptance

AMI technology may raise concerns among consumers about the privacy and security of their energy usage data. Utilities must communicate effectively with their customers and ensure that their privacy is protected.

Technical limitations

Technical limitations such as outdated infrastructure, limited communication networks, and system malfunctions can also pose challenges to implementing AMI. These limitations must be addressed before the technology can be adopted on a large scale.

Integration

AMI is a complex system of technologies that must be integrated with utilities' information technology systems, including Customer Information Systems (CIS), Geographical Information Systems (GIS), Outage Management Systems (OMS), Work Management (WMS), Mobile Workforce Management (MWM), SCADA/DMS, Distribution Automation System (DAS), etc.

While AMI holds great promise for improving energy efficiency and reducing costs, its implementation must be approached with caution. Utilities must consider the cost, interoperability, privacy and security, public acceptance, and technical limitations associated with AMI and work to address these challenges to ensure a successful implementation.

Advanced Metering Infrastructure - The Indian Context

The implementation of AMI in India has been gaining momentum in recent years, as the country strives to improve the efficiency and reliability of its electricity supply.

In India, the implementation of AMI is driven by several factors, including the need to reduce electricity theft and meter tampering, improve billing accuracy, and enhance the management of the electricity grid. The use of smart meters also allows for real-time monitoring of electricity usage, which can help consumers better understand their energy consumption patterns and make more informed decisions about how they use electricity.

The Indian government has been actively promoting the adoption of AMI and has established many initiatives and programs aimed at encouraging its implementation. For example, the government has introduced subsidies and tax incentives for the deployment of smart meters and has launched pilot projects to demonstrate the benefits of AMI to consumers and the utility industry.

Despite the many benefits of AMI, the implementation of this technology in India faces several challenges. One of the biggest obstacles is the cost of deploying the technology, which can be prohibitively high for many utilities and consumers. Additionally, there are concerns about the privacy and security of energy data, as well as the reliability and durability of the meters themselves.

To overcome these challenges, the Indian government has been working with the utility industry to establish best practices and standards for the deployment and operation of AMI. This includes the development of security protocols to protect energy data, as well as the establishment of training programs for technicians and other personnel involved in the implementation of AMI.

The implementation of AMI in India has the potential to revolutionize the way electricity is managed and consumed in the country. By providing real-time monitoring and management of energy usage, AMI can help improve the efficiency and reliability of the electricity grid, while also empowering consumers to make more informed decisions about their energy consumption. However, significant challenges remain in terms of cost and privacy, and the Indian government and utility industry will need to work together to overcome these obstacles and ensure the successful implementation of AMI in India. In particular, AMI will improve three key features of India's grid system including:

- System Reliability: AMI technology improves the distribution and overall reliability of electricity by enabling electricity distributors to identify and automatically respond to electric demand, which in turn minimizes power outages.
- Energy Costs: Increased reliability and functionality, reduced power outages, and streamlined billing operations will dramatically cut costs associated with providing and maintaining the grid, thereby significantly lowering electricity rates.
- Electricity Theft: Power theft is a common problem in India. AMI systems that track energy usage will help monitor power almost in real time thus leading to increased system transparency.

In conclusion, Advanced Metering Infrastructure (AMI) is a vital component in modernizing the energy sector. Its implementation offers numerous benefits such as improved efficiency, enhanced customer service, and increased energy savings. With the use of smart meters and real-time data monitoring, energy companies can gain a better understanding of energy usage patterns, reducing the need for manual meter readings and minimizing errors. The integration of AMI technology into the energy sector is crucial in creating a more sustainable and reliable energy future. Overall, AMI has the potential to revolutionize the way energy is distributed and consumed, making it a crucial investment for energy companies and consumers alike.

NETL Modern Grid Strategy
Powering our 21st-Century Economy

ADVANCED METERING INFRASTRUCTURE

Conducted by the National Energy Technology Laboratory
for the U.S. Department of Energy
Office of Electricity Delivery and Energy Reliability
February 2008

Office of Electricity
Delivery and Energy
Reliability

DISCLAIMER

TABLE OF CONTENTS

Table of Contents 1

Executive Summary 2

What is AMI? 5

What are the technology options for AMI? 7

What are some deployment approaches? 11

What are the benefits of AMI? 12

What policies apply to AMI? 17

What barriers impact successful deployment of AMI? 20

What are the business case considerations? 21

What are some experiences with AMI to date? 23

Summary 26

Call to Action 29

Bibliography 30

Acronyms 31

EXECUTIVE SUMMARY

Deploying an Advanced Metering Infrastructure (AMI) is a fundamental early step to grid modernization. AMI provides the framework for meeting one of the Modern Grid's Principal Characteristics – Motivation and Inclusion of the Consumer.

AMI is not a single technology, but rather an integration of many technologies that provides an intelligent connection between consumers and system operators. AMI gives consumers the information they need to make intelligent decisions, the ability to execute those decisions and a variety of choices leading to substantial benefits they do not currently enjoy. In addition, system operators are able to greatly improve consumer service by refining utility operating and asset management processes based on AMI data.

Through the integration of multiple technologies (such as smart metering, home area networks, integrated communications, data management applications, and standardized software interfaces) with existing utility operations and asset management processes, AMI provides an essential link between the grid, consumers and their loads, and generation and storage resources. Such a link is a fundamental requirement of a Modern Grid.

Figure 1 below illustrates how AMI is the first step to the overall Modern Grid vision.

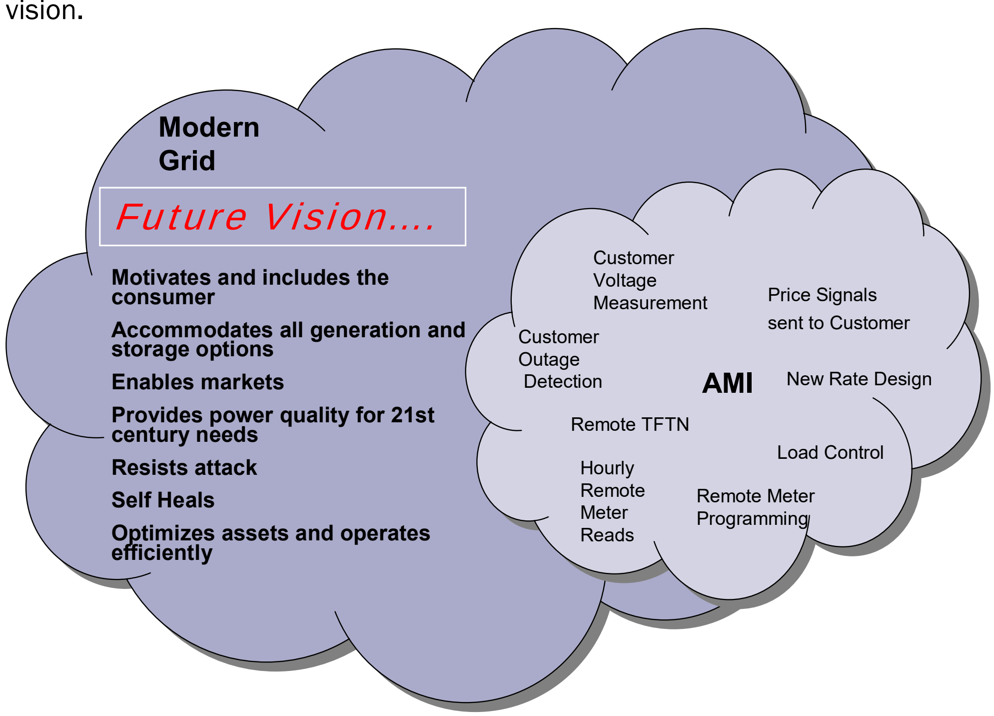


Figure 1: AMI – The first step to a Modern Grid

How does AMI support the vision for the Modern Grid? Initially, Automated Meter Reading (AMR) technologies were deployed to reduce costs and improve the accuracy of meter reads. A growing understanding of the benefits of two-way interactions between system operators, consumers and their loads and resources led to the evolution of AMR into AMI. The vision of the Modern Grid's seven principal characteristics (Figure 1) further reinforces the need for AMI:

- *Motivation and inclusion of the consumer* is enabled by AMI technologies that provide the fundamental link between the consumer and the grid.
- *Generation and storage options* distributed at consumer locations can be monitored and controlled through AMI technologies.
- *Markets are enabled* by connecting the consumer to the grid through AMI and permitting them to actively participate, either as load that is directly responsive to price signals, or as part of load resources that can be bid into various types of markets,
- AMI smart meters equipped with *Power Quality* (PQ) monitoring capabilities enable more rapid detection, diagnosis and resolution of PQ problems.
- AMI enables a more distributed operating model that reduces the *vulnerability of the grid to terrorist attacks*.
- AMI provides for *self healing* by helping outage management systems detect and locate failures more quickly and accurately. It can also provide a ubiquitous distributed communications infrastructure having excess capacity that can be used to accelerate the deployment of advanced distribution operations equipment and applications.
- AMI data provides the granularity and timeliness of information needed to greatly *improve asset management and operations*.

The purpose of this document is to describe AMI and discuss how it contributes to the achievement of the overall Modern Grid vision. AMI can be the first of four major milestones on the road to a modern grid:

- Advanced Metering Infrastructure (AMI)
- Advanced Distribution Operations (ADO)
- Advanced Transmission Operations (ATO)
- Advanced Asset Management (AAM)

By properly sequencing these milestones, a more cost effective modernization program can be achieved.

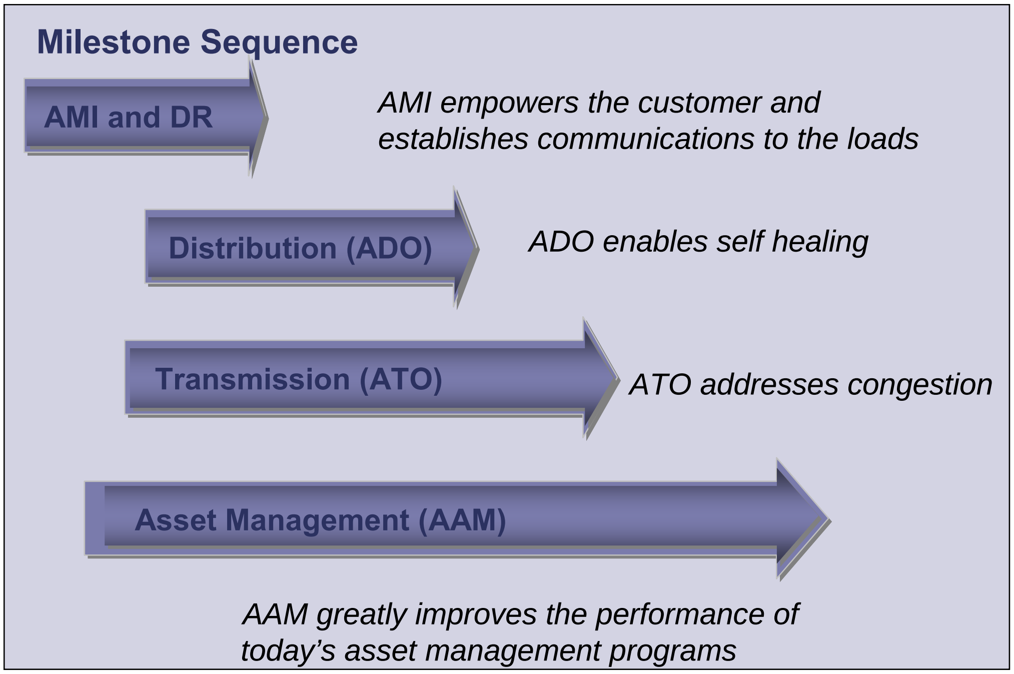


Figure 2: Milestone Sequence

A well-crafted sequence will allow applications to build on previous accomplishments, as shown below.

Sequence Has Value	
AMI	• Establishes communications with the consumer • Provides time stamped system information
ADO	• Uses AMI communications to collect distribution information • Uses AMI information to improve operations
ATO	• Uses ADO information to improve operations and manage transmission congestion and voltage • Uses AMI to give consumers access to markets
AAM	• Uses AMI, ADO, and ATO information and controls to improve: o Operating efficiency o Asset utilization

Figure 3: Sequence Has Value

WHAT IS AMI?

AMI is not a single technology implementation, but rather a fully configured infrastructure that must be integrated into existing and new utility processes and applications.

This infrastructure includes home network systems, including communicating thermostats and other in-home controls, smart meters, communication networks from the meters to local data concentrators, back-haul communications networks to corporate data centers, meter data management systems (MDMS) and, finally, data integration into existing and new software application platforms. Additionally, AMI provides a very "intelligent" step toward modernizing the entire power system. Figure 4 below graphically describes the AMI technologies and how they interface:

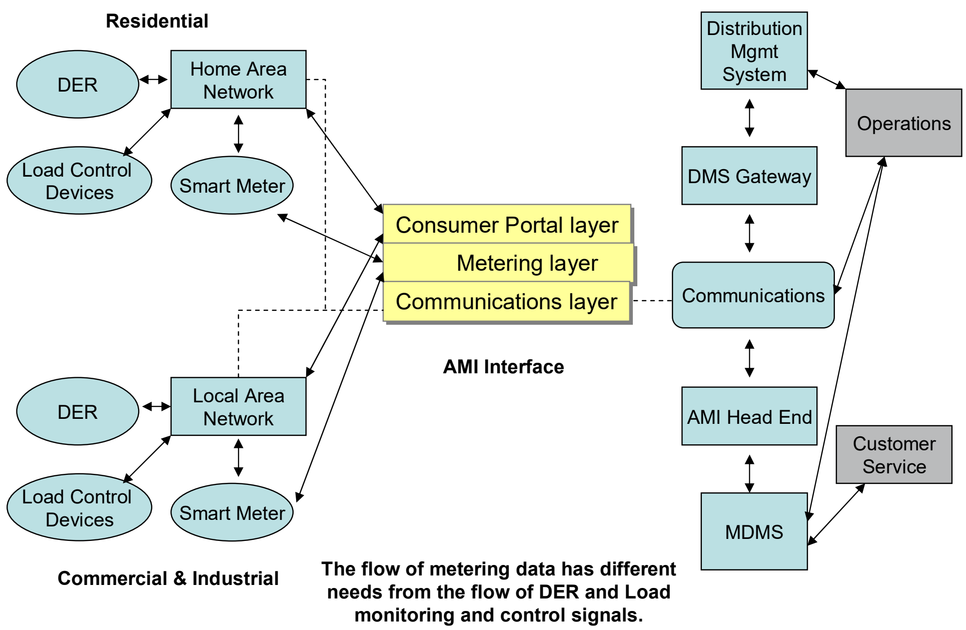


Figure 4: Overview of AMI

At the consumer level, smart meters communicate consumption data to both the user and the service provider. Smart meters communicate with in-home displays to make consumers more aware of their energy usage. Going further, electric pricing information supplied by the service provider enables load control devices like smart thermostats to modulate electric demand, based on pre-established consumer price preferences. More advanced customers deploy distributed energy resources (DER) based on these economic signals. And consumer portals process the AMI data in ways that enable more intelligent energy consumption decisions, even providing interactive services like prepayment.

The service provider (utility) employs existing, enhanced or new back office systems that collect and analyze AMI data to help optimize operations, economics and consumer service. For example, AMI provides immediate feedback on consumer outages and power quality, enabling the service provider to rapidly address grid deficiencies. And AMI's bidirectional communications infrastructure also supports grid automation at the station and circuit level. The vast amount of new data flowing from AMI allows improved management of utility assets as well as better planning of asset maintenance, additions and replacements. The resulting more efficient and reliable grid is one of AMI's many benefits.

WHAT ARE THE TECHNOLOGY OPTIONS FOR AMI?

An AMI system is comprised of a number of technologies and applications that have been integrated to perform as one:

- Smart meters
- Wide-area communications infrastructure
- Home (local) area networks (HANs)
- Meter Data Management Systems (MDMS)
- Operational Gateways

SMART METERS

Conventional electromechanical meters served as the utility cash register for most of its history. At the residential level, these meters simply recorded the total energy consumed over a period of time – typically a month. Smart meters are solid state programmable devices that perform many more functions, including most or all of the following:

- Time-based pricing
- Consumption data for consumer and utility
- Net metering
- Loss of power (and restoration) notification
- Remote turn on / turn off operations
- Load limiting for "bad pay" or demand response purposes
- Energy prepayment
- Power quality monitoring
- Tamper and energy theft detection
- Communications with other intelligent devices in the home

Figure 5: A Modern Solid State Smart Meter (left) and an older Electromechanical Watt hour Meter

And a smart meter is a green meter because it enables the demand response that can lead to emissions and carbon reductions. It facilitates greater energy efficiency since information feedback alone has been shown to cause consumers to reduce usage.

COMMUNICATIONS INFRASTRUCTURE

The AMI communications infrastructure supports continuous interaction between the utility, the consumer and the controllable electrical load. It must employ open bi-directional communication standards, yet be highly secure. It has the potential to also serve as the foundation for a multitude of modern grid functions beyond AMI. Various architectures can be employed, with one of the most common being local concentrators that collect data from groups of meters and transmit that data to a central server via a backhaul channel. Various media can be considered to provide part or all of this architecture:

- Power Line Carrier (PLC)
- Broadband over power lines (BPL)
- Copper or optical fiber
- Wireless (Radio frequency), either centralized or a distributed mesh
- Internet
- Combinations of the above

Future inclusion of smart grid applications and potential consumer services should be considered when determining communication bandwidth requirements.

HOME AREA NETWORKS (HAN)

A HAN interfaces with a consumer portal to link smart meters to controllable electrical devices. Its energy management functions may include:

- In-home displays so the consumer always knows what energy is being used and what it is costing
- Responsiveness to price signals based on consumer-entered preferences
- Set points that limit utility or local control actions to a consumer-specified band
- Control of loads without continuing consumer involvement
- Consumer over-ride capability

The HAN/consumer portal provides a smart interface to the market by acting as the consumer's "agent." It can also support new value added services such as security monitoring.

A HAN may be implemented in a number of ways, with the consumer portal located in any of several possible devices including the meter itself, the neighborhood collector, a stand-alone utility-supplied gateway or even within customer-supplied equipment.

Meter Data Management System (MDMS)

A MDMS is a database with analytical tools that enable interaction with other information systems (see Operational Gateways below) such as the following:

- Consumer Information System (CIS), billing systems, and the utility web site
- Outage Management System (OMS)
- Enterprise Resource Planning (ERP) power quality management and load forecasting systems
- Mobile Workforce Management (MWM)
- Geographic Information System (GIS)
- Transformer Load Management (TLM)

One of the primary functions of an MDMS is to perform validation, editing and estimation (VEE) on the AMI data to ensure that despite disruptions in the communications network or at customer premises, the data flowing to the systems described above is complete and accurate.

Operational Gateways

AMI interfaces with many system-side applications (see MDMS above) to support:

Advanced Distribution Operations (ADO)

- Distribution Management System with advanced sensors (including PQ data from AMI meters)
- Advanced Outage Management (real-time outage information from AMI meters)
- DER Operations (using Watt and VAR data from AMI meters)
- Distribution automation (including Volt/VAR optimization and fault location, isolation, sectionalization and restoration (FLISR))
- Distribution Geographic Information System
- Application of AMI communications infrastructure for:
    - Micro-grid operations (AC and DC)
    - Hi-speed information processing
    - Advanced protection and control
    - Advanced grid components for distribution

Advanced Transmission Operations (ATO)

- Substation Automation
- Hi-speed information processing
- Advanced protection and control (including distribution control to improve transmission conditions)
- Modeling, simulation and visualization tools
- Advanced regional operational applications
- Electricity Markets

Advanced Asset Management (AAM)

AMI data will support AAM in the following areas:

- System operating information
- Asset "health" information
- Operations to optimize asset utilization
- T&D planning
- Condition-based maintenance
- Engineering design and construction
- Consumer service
- Work and resource management
- Modeling and simulation

WHAT ARE SOME DEPLOYMENT APPROACHES?

Deployment approaches will depend upon the utility's starting point, geography, regulatory situation and long-term vision. For those utilities that already have deployed an AMR system, the question will be whether they can build on that system or need to start afresh. If the system includes a two-way communications infrastructure, it should be possible to upgrade the metering to accommodate a range of AMI applications. Where the communications infrastructure is unidirectional (i.e. outgoing only), it may be possible to overlay a return channel using a complementary technology. This option would have to be compared to the cost and benefits of installing a new integrated two-way communications infrastructure. The speed, reliability and security of the communications infrastructure will determine the range of applications it can support. For utilities with widespread and diverse territories, it may be that multiple communications solutions will be needed. Pilot programs that explore the performance of various solutions can be useful as the first phase of an AMI deployment.

The choice of an AMI communications infrastructure is also influenced by the utility's long-term vision for AMI. If AMI is seen as the foundation for overall grid modernization, the communications system will need to accommodate anticipated future needs and have the flexibility to handle applications that are not even currently on the utility's radar screen. Experience has shown that these evolving grid modernization applications often produce major benefits, as discussed in later sections.

The deployment of AMI is a strategic initiative that must be endorsed by the utility regulator. The benefits of AMI, and ultimately of overall grid modernization, flow to not just the utility, but also to the consumer and society in general. Hence regulators need to consider the possibility that traditional utility economic analysis may not capture the true value of an AMI strategic initiative and that an expanded framework may be more appropriate, as discussed later in this document. Some regulators may see AMI and grid modernization as very desirable and they will encourage their utilities to move aggressively. Others may be less proactive and will expect their utilities to broach AMI and bring with them a compelling argument on its merits. In either case, recognition of the wide-ranging societal benefits of AMI must be addressed.

Together, the utility and its regulators should communicate the full benefits of an AMI initiative to consumers and society at large. There is a general lack of understanding among the public regarding how electricity is produced and delivered, how it affects their quality of life and how it can meet their needs in the 21st century. In particular, the value of consumers' increased involvement in electricity markets, and the potential benefits for consumers involved in such programs needs to be explained.

WHAT ARE THE BENEFITS OF AMI?

AMI provides benefits to consumers, utilities and society as a whole.

CONSUMER BENEFITS

For the consumer, this means more choices about price and service, less intrusion and more information with which to manage consumption, cost and other decisions. It also means higher reliability, better power quality, and more prompt, more accurate billing . In addition, AMI will help keep down utility costs, and therefore electricity prices. And, as members of society, consumers also reap all the benefits that accrue to society in general, as described below.

UTILITY BENEFITS

Utility benefits fall into two major categories, billing and operations.

AMI helps the utility avoid estimated readings, provide accurate and timely bills, operate more efficiently and reliably, and offer significantly better consumer service. AMI eliminates the vehicle, training, health insurance, and other overhead expenses of manual meter reading, while the shorter read-to-pay time advances the utility's cash flow, creating a one-time benefit. And consumer concerns about meter readers on their premises are eliminated.

Operationally, with AMI the utility knows immediately when and where an outage occurs so it can dispatch repair crews in a more timely and efficient way. Meter-level outage and restoration information accelerates the outage restoration process, which includes notifying consumers about when power is likely to return.

Using AMI, the utility can receive significant benefits from being able to manage customer accounts more promptly and efficiently, starting with the ability to remotely connect and disconnect service without having to send personnel to the customer site. Similarly, many maintenance and customer service issues can be resolved more quickly and cost-effectively through the use of remote diagnostics. And AMI enables new programs and methods for creating and recovering revenue such as distributed generation and prepayment programs.

AMI also provides vast amounts of energy usage and grid status information that can be used by consumers to make more informed consumption decisions and by utilities to make better decisions about system improvements and service offerings.

Instead of relying on rough estimates, engineers armed with AMI's detailed knowledge of distribution loads and electrical quality can accurately size equipment and protection devices, and better understand distribution system behavior. This huge increase in valuable information helps the utility:

- Assess equipment health
- Maximize asset utilization and life
- Optimize maintenance, capital and O&M spending
- Pinpoint grid problems
- Improve grid planning
- Locate/ identify power quality issues
- Detect/reduce energy theft

Societal Benefits

Society, in general, benefits from AMI in many ways. One way is through improved efficiency in energy delivery and use, producing a favorable environmental impact. It can accelerate the use of distributed generation, which can in turn encourage the use of green energy sources. And it is likely that emissions trading will be enabled by AMI's detailed measurement and recording capabilities.

A major benefit of AMI is its facilitation of demand response and innovative energy tariffs. During periods of high energy demand, a small reduction in demand produces a relatively large reduction in the market price of electricity. And reduced demand can avoid rolling blackouts. According to Edison Electric Institute (EEI), the direct costs (e.g. power costs) of rolling blackouts in California have been estimated at tens of millions of dollars. Business and consumer losses may be many times higher. Hence, a modest demand response capability could produce a societal benefit worth billions of dollars.

The benefits accrued may vary depending on the type of demand response programs initiated. For instance, demand response distributed to the individual premise in forms like thermostat and pool pump control allows load to be reduced without sacrificing consumer satisfaction. However, even just shifting demand away from peak hours through time-of-use tariffs can have major benefits, including the reduced cost to both utilities and consumers by deferring building new, expensive peak generation facilities.

There is also a societal fairness issue that AMI addresses. Full deployment of AMI results in the elimination of old and obsolete electromechanical meters that tend to slow down as they age. Modern AMI meters maintain their accuracy over time, resulting in a more equitable situation for all consumers. In addition, modern meters are self monitoring, making it easier to identify inaccurate measurements, incorrect installations and, especially, electric energy theft.

As reported by Edison Electric Institute (EEI), price and demand reductions during high-demand periods lead to:

- Reduced
  - peak capacity requirements

- o congestion costs
- o T&D costs
- o electrical losses
- o generation costs
- o market influence by any one supplier

- Improved
    - o electric system efficiency (lower operating costs)
    - o electric system reliability (lower maintenance costs)
    - o settlement data management

Added Benefits When AMI Serves As a Modern Grid Platform

Since smart metering and demand response programs can be one of the foundations of a modern grid, it is wise to also assess the associated communications infrastructure strategy to identify incremental investments in communications that might benefit the functional needs of ADO, ATO and AAM (see Operational Gateways above).

Increased bandwidth and broader area coverage generally lead to more opportunities for grid modernization. In other words, a ubiquitous AMI communications network could be designed, for a small incremental cost, to also accommodate transmission and distribution automation systems, reducing the total cost of both AMI and other forms of grid modernization. And a useful by-product could be the use of excess bandwidth to provide broadband services, such as internet access and voice over IP, to consumers.

Enhanced functionality can be achieved when the AMI infrastructure sequences into a fully enabled modern grid (see Figure 2.). When that occurs, EPRI (Electric Power Research Institute) estimates that at least a 4 to 1 total benefit to cost ratio will be realized.

As described in other Modern Grid Strategy white papers, achieving the vision of the Modern Grid depends on the correct and effective deployment of technologies and applications in five key technology areas (KTAs). AMI relates to each of these KTAs as described below:

- **Integrated Communications:** AMI provides the last and by far the most extensive link between the grid (including the consumer's load) and the system operator.
- **Sensing and Measurement:** Smart meters extensively measure system conditions (including PQ) down to the consumer level.
- **Advanced Control Methods:** Consumer-side applications process information and initiate control actions locally (sometimes based on real time pricing). Distribution operations centers process AMI information and take control actions at the system and regional level.
- **Advanced Grid Components:** AMI supports the deployment of distributed energy resources and can reduce the communication network costs of deploying pole-top distribution automation components.

- **Improved Interfaces & Decision Support:** AMI consumer portals, home area networks, and in-home displays provide the human interface and support consumer decision-making. Decision support at distribution operations centers is enabled by the additional information provided by AMI.

Common to all modern grid characteristics and key technologies is the pivotal role of information and knowledge. AMI information can support the vast majority of electric industry processes, as shown in Figure 6.

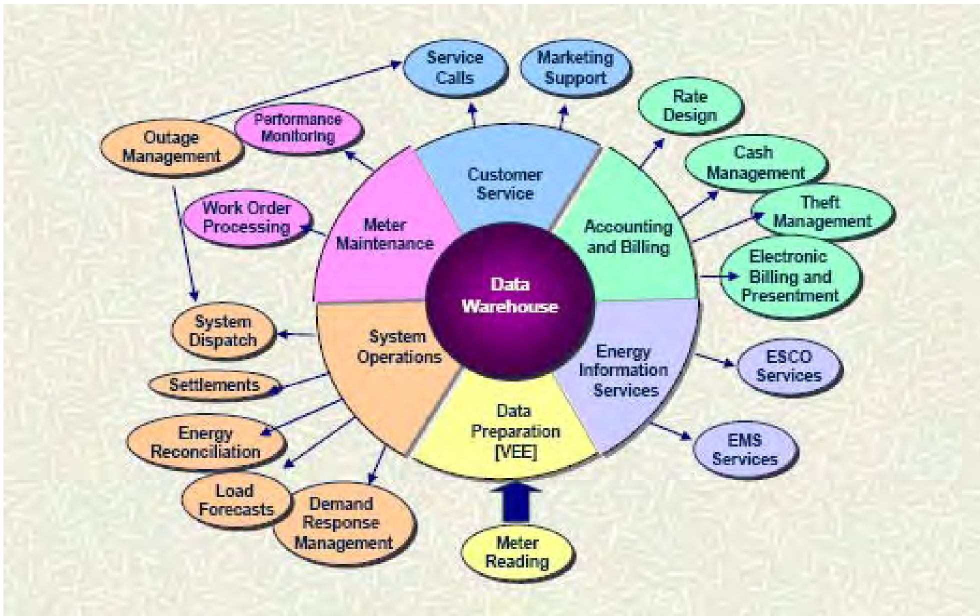


Figure 6 Full Utility Perspectives (Levy Associates, 2005)

It is clear from all the above that AMI provides many benefits to a wide variety of stakeholders, and that going beyond AMI to achieve a truly modern grid produces additional large improvements in the operations of an electric utility.

The list of benefits includes:

- Greatly improved outage management system (through links with GIS and real time consumer status)
- Improved system planning process and results
- Improved distribution asset management programs including equipment health assessment and condition-based maintenance
- Advanced distribution management systems (distribution automation, integrated operation of DR (and DER), micro-grid operation, self-healing, etc.)
- Improved mobile workforce management and operations
- New opportunities for consumer choice and new retail services
- Improvements to power quality issues

- Reduced environmental impact
- Distribution system support of transmission operations (transmission congestion relief, voltage support, loss reduction)

The MGS publication "Modern Grid Benefits" provides a more detailed discussion of modern grid benefits, including those that accrue to society as a whole.

WHAT POLICIES APPLY TO AMI?

HISTORY

For most of the history of the electricity industry, the area of metering has not seen major policy issues or developments. Those issues that did develop dealt with areas such as meter accuracy testing, frequency of billing, and other aspects of the meter reading function. Most of these were addressed via state legislation or regulation. There was little, if any, federal policy enacted with respect to metering.

Given that metering is part of the infrastructure of a regulated utility, and is in part a capital expense, metering investments by utilities have always been subject to the approval of policy makers. But this has mainly come in the form of specific approvals via rate cases and other policy proceedings. While involving policy makers, the proceedings to deal with costs have not been generic policy proceedings.

In the 1990's as a number of states moved to restructure their electricity industry to make the commodity subject to competitive retail markets, some states, notably New York and Texas, went further and "unbundled" or opened up distribution services such as metering for competition. The intent of this policy was to spur the introduction of advanced meters faster than the regulated system appeared to be deploying them.

Competitive metering did not work very well. The costs of ad hoc metering deployment (i.e. where meters are put in sporadically and with no geographic cohesion or proximity) proved to be 5 to 10 times the cost per meter as compared to a mass deployment by the utility. Competitive metering policy had even worse impacts on the deployment of advanced metering. Because such policy granted competitors the ability to take away the metering part of the utility franchise, utilities around the country – not just in New York and Texas - quickly became wary of making metering investments that could potentially become stranded. Thus, competitive metering policy actually froze the introduction of advanced metering instead of fostering and accelerating it. Both Texas and New York have rescinded their competitive metering policy.

RECENT DEVELOPMENTS

Beginning in 2000, metering became a more important issue in the eyes of policy makers and the electricity industry. New metering and communications technologies brought forward new benefits. Most importantly, however, the rise in interest in demand response as a new policy and business component of the electricity industry– both at the wholesale and retail level – began to drive interest in advanced metering. This new interest in AMI occurred because demand response could now be based on a better ability to monitor and verify the time at which electricity was used.

FEDERAL POLICY

The first major federal policy on electricity metering was enacted in 2005. The Energy Policy Act of 2005 (EPACT) contained a Section entitled "Smart Metering." The Section put in place the following policy:

- Requirement on states and non-regulated utilities to investigate and consider providing Time-Based Rates and Advanced Metering to all consumers.
- Requirement that FERC conduct an annual assessment on demand response and advanced metering, which would include among other things, a national survey to determine the penetration and saturation of advanced metering.
- Requirement that DOE issue a report to Congress on demand response potential, together with recommendations on how to use policy to overcome barriers to advanced metering and demand response.
- Requirement that all Federal Buildings be equipped with advanced metering.

Both FERC and DOE completed their Requirements on time and both are available as reference documents (see bibliography). Both include discussion of potential policy options. In the case of the FERC assessment, the survey conducted represents the first nationwide survey on advanced metering.

The Federal Buildings Requirement has resulted in all federal agencies developing metering plans. They are now in the process of implementing those plans.

The requirement upon states, municipalities and cooperative boards has, for the most part, been pursued diligently by those entities affected. The language of EPACT required that investigations be concluded and decisions reached by August of 2007. More information on state developments in this area is available at www.demandresponsecommittee.org.

In December of 2007, new energy legislation entitled the Energy Independence and Security Act of 2007 was signed into law. Title XIII addresses the development of a Smart Grid. This new law will serve as a major catalyst for rapid deployment of AMI and grid modernization.

STATE POLICY

As is the case at the Federal level, States have begun to move in recent years to put policy in place that directly or indirectly affects the metering area. Much of it has come in response to the EPACT investigation requirement noted in the previous section. In some cases, States had initiated policy efforts prior to EPACT; in other cases, States have decided not to strictly implement the EPACT requirement but have instead set other policies in place or in motion to move the state forward on demand response and advanced metering. Many states have begun pilot programs that incorporate demand response and advanced metering. Among the states that are notable for their self-initiated efforts are New York, Texas, Connecticut and California.

California is an interesting example. Policy was first put in place to require a statewide level of demand response by a specified date. Then rules were established to require statewide deployment of advanced metering as the means of achieving the demand response policy. In the case of California, the Public Utility Commission first conducted a generic policy process to establish advanced metering objectives, requirements, etc. Then each of the major utilities was required to present to the Commission for its approval a business case on how to implement the generic policy in a way best suited to their individual situations.

One of the areas facing States with respect to metering is the need to facilitate the replacement of existing meters and metering systems with new technology and infrastructure – even though the existing metering may still be within its useful life and may also still be functioning satisfactorily for its original intended purpose. Recognizing this issue, the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) in February of 2007 adopted a resolution calling for Commissions to recognize the need to consider faster regulatory depreciation of existing meters and metering systems.

WHAT BARRIERS IMPACT SUCCESSFUL DEPLOYMENT OF AMI?

The transition to AMI and ultimately to a modern grid is not without obstacles.

- **Business Case Limitations:** Limiting the assessment of AMI benefits to just those associated with utility operations biases the business case against deployment. A more complete societal business case often produces a different conclusion. If one includes such items as the avoided societal costs and consequences of rolling and regional blackouts, AMI benefits can be many times the utility operating benefits. While some of these benefits accrue to constituents outside the utility, they are nonetheless direct consequences of AMI and should be addressed in the business case.
- **Depreciation Rules:** The accounting treatment of the value of in-service meters is another important element in any AMI decision. In most cases it will be necessary to replace obsolete meters before they have been fully depreciated, creating a write-down (i.e. an expense that reduces utility earnings) that can affect regulated income.
- **Standards:** While AMI technology is moving at a rapid pace, standards are needed to ensure interoperability among the many AMI offerings. Open standards are the best way to drive down the costs of AMI deployments and to give utilities the assurance that a large AMI investment will not become stranded if the selected vendor fails.
- **Rate Designs:** Innovative rate designs that reflect actual market conditions are needed to complement the capabilities of AMI technology and realize the potential of demand response. Current ratemaking structures make it difficult to roll out new technologies. Utilities that install energy-saving systems can see their sales drop without any offsetting benefit
- **Education:** Consumer education is needed regarding the merits of AMI, DR and the societal benefits from grid modernization. Consumers also need to understand and demand a modern electric grid that will improve their overall quality of life and enhance US competitiveness in a global economy.
- **Technical Resources:** Utility and vendor technical staffs have been cut back over the past decade. Rebuilding these staffs and attracting the needed technical talent is a barrier to the full realization of AMI's potential.
- Regulatory Barriers - Overlapping federal, regional, state and municipal agencies create an impediment. The industry is neither fully regulated nor completely deregulated.
- Financial Constraints - The grid is capital intensive and faces problems imposed by utilities' constrained balance sheets.
- Technology Hurdles – It is a challenge to "fix a moving train." Utilities cannot turn off the power for a year or two while they install upgrades.

WHAT ARE THE BUSINESS CASE CONSIDERATIONS?

The development of the AMI business case can be conceptually straight forward, but difficult in the quantification of details.

Instead of the conventional regulatory framework, a more expansive AMI framework (Figure 7) has been suggested by Levy Associates. This new framework is expected to produce a very positive business case for both AMI and grid modernization in general. Conversely, the traditional framework is likely to produce only a marginal net benefit.

Comparing Business Case Options

	Conventional Framework	Proposed Framework
1	Methodology - Net Present Value of Costs and Benefits.	Methodology - Net Present Value of Costs and Benefits
2	Utility owns and rate bases all investment.	Consider financed or outsourced options.
3	Focus on utility revenue requirement.	Focus on system wide net benefits.
4	Metering assumed independent of other systems and applications.	Metering considered part of an integrated suite of utility applications.
5	Customer impacts not considered.	Customer impacts considered.
6	Demand response, innovative pricing and customer education not considered.	Demand response, innovative pricing and customer education considered.
7	New customer service and revenue opportunities not considered.	New customer service and revenue opportunities considered.

Figure 7 Comparing Business Case Options (Levy Associates, 2005)

In the discussion paper “The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs” (Faruqui, 2007), the Brattle Group estimates that full AMI deployment across the US would cost about $26 billion and that utility operational savings would cover anywhere from 50% to 80% of this cost. It then goes on to estimate a long-run generation, transmission and distribution system capital savings of $35 billion, along with an additional $5 to 10 billion per year in reduced electricity prices.

Using an average of 65% for utility operational savings as an expected value, the remaining cost to be justified would be $9.1 billion (.35 x $26 billion). Since the long-run savings in capital investment is $35 billion, the benefit/cost ratio is about 4:1. Adding in the resulting reduced electricity prices, a particular concern to low income consumers, makes the case all the more compelling.

And, as suggested in Figure 7, additional benefits such as improved reliability and power quality, greater consumer choice, reduced environmental impact and others associated with a modern grid should also be recognized.

WHAT ARE SOME EXPERIENCES WITH AMI TO DATE?

Some utilities have been moving in the direction of AMI for a number of years.

As their experience has grown, so has their insight into the advantages of moving beyond AMR to AMI and eventually to a smart or modern grid. The following cases illustrate that evolution and describe ways to approach an AMI deployment. It is important to note that a number of applications not initially contemplated are now adding great value. This strongly suggests that AMI systems that have the flexibility to readily accommodate new applications will prove to be the best long-term investments. Close coordination and cooperation between state regulators and utilities is a key to a smooth, successful AMI deployment.

CASE 1

A Southeastern utility (see bibliography; "Meter Data Management System - What, Why, When, and How.") that primarily used AMI technologies for billing, added an integrated MDMS. As a result:

- Costs of billing research are now being reduced by 25%
- 95% of field service orders for special reads have been eliminated
- A 30% improvement in theft detection and recovery is being realized
- Trouble call handling costs are being reduced by 25%

In addition, consumer satisfaction and service reliability have improved.

CASE 2

The following excerpts from John Luth's (2006) "10 Years of Results: AmerenUE's AMR Business Case Evolves to Support AMI" describe one utility's decade-long transition from AMR to AMI.

1994–1997: The UE Business Case & Initial Rollout

By early 1997, nearly 400,000 St. Louis area meters were on-line delivering 24x7 data available in 15-minute increments.

The initial business case was conservative. It focused largely on rapid payback, hard-dollar benefits across areas including meter reading, customer service and operations.

A Platform for the Future

Anticipated benefits beyond hard-dollar meter reading savings were a significant part of UE's decision to begin implementing a wireless fixed-network AMR system. The original sponsoring executives and the UE project team saw the implementation as a long-range strategic initiative that would ultimately help achieve the corporate goals of maintaining competitive energy costs while improving customer service. Early project charters also emphasized the longer term vision of implementing an intelligent network platform.

From Meter Read Savings to Advanced Distribution Applications

[Figure 2 depicts] the change in relative percentage values across a sampling of Ameren business case benefit categories comparing the original 1996 values with relative values taken from 2003 when the system was deployed to nearly 1.4 million end points.

Figure 2
Comparison of Relative Total Benefit Percentages across a Sample of AmerenUE Business Case

Selected Benefit Area	1996 Percentage	2003 Percentage
Meter Labor Savings	43	26
Vehicle & Office Savings	5	3
Move In/Move Out	31	25
High Bill Special Reads	0	1
Meter Accuracy Improvements	8	8
High Bill & Outage Calls	2	2
Estimated Bills Savings	3	1
Single Light Out	5	3
Load Analysis & Research	0	2
Energy Theft Savings	3	3
Improved Cash Flows	0	6
Load & Distribution Network Optimization	0	20

What is particularly revealing is a review of the change in relative value in the area of load management and distribution network optimization. This is now a major benefit area with many components that are summarized in the category “load and distribution network optimization.”

CASE 3

Internationally, there are a number of AMI installations, as described in the following list (see bibliography; “Advanced Metering Infrastructure – MGI View”)**:**

- Italy’s Enel has installed over 27 million communicating solid-state meters. (completed in 2006 – 4 year ROI)
- Sweden’s Vattenfall is in middle of rolling out 600,000 advanced meters and E.ON Sweden is in the early stages of rolling out 370,000 advanced meters.
- The Netherlands government has announced its intent to replace all 7.5 million electric meters in the country by the end of 2012.
- In Austria, Linz STROM recently announced plans to deploy advanced meters to 75,000 of its customers.
- In Canada, Hydro One has begun installation of smart meters in southern Ontario and expects to complete the installation of 1.3 million throughout its service territory by 2010.
- Norway recently announced a smart meter roll-out to 2.6 million customers by 2013.
- Australia/United Kingdom and others.

SUMMARY

AMI is an integration of technologies that provides an intelligent connection between consumers and system operators. Through the integration of technologies such as smart metering, home area networks, integrated communications, data management applications, and software interfaces with existing utility operations and asset management processes, AMI provides the needed link between the grid, consumers and their loads, and generation and storage resources – a link that is fundamental to the creation of a Modern Grid.

AMI is the first of four major modern grid milestones:

- Advanced Metering Infrastructure (AMI)
- Advanced Distribution Operations (ADO)
- Advanced Transmission Operations (ATO)
- Advanced Asset Management (AAM)

By properly sequencing these milestones, the most cost effective modernization program can be achieved.

AMI deployment approaches will depend upon the utility's starting point, geography, regulatory situation and long-term vision. Pilot programs that explore the performance of various solutions can be useful as the first phase of an AMI deployment. The choice of an AMI communications infrastructure is influenced by the utility's long-term vision for AMI. If AMI is seen as the foundation for overall grid modernization, the communications system will accommodate anticipated future needs and have the flexibility to even handle applications that are not currently on the utility's radar screen.

Utilities have been moving in the direction of AMI for a number of years. As their experience has grown, so has their insight into the advantages of moving beyond AMR to AMI and eventually to a smart or modern grid.

The first major federal policy on electricity metering was enacted in 2005. The Energy Policy Act of 2005 (EPACT) contained a Section entitled "Smart Metering." Many states have begun pilot programs that incorporate demand response and advanced metering. Among the states that are notable for their self-initiated efforts are New York, Texas, Connecticut and California.

In December of 2007, new energy legislation entitled the Energy Independence and Security Act of 2007 was signed into law. Title XIII addresses the development of a Smart Grid. This new law will serve as a major catalyst for rapid deployment of AMI and grid modernization.

The transition to AMI and ultimately to a modern grid is not without obstacles. Areas of concern include business case limitations, standards, depreciation rules, rate designs, education, and technical resources.

Traditional utility economic analysis may not capture the true value of an AMI strategic initiative; an expanded framework may be more appropriate since AMI provides benefits to consumers, utilities and society as a whole.

For the consumer, this means more choices about price and service, less intrusion and more information with which to manage consumption, cost and other decisions.

AMI helps the utility avoid estimated readings, provide accurate and timely bills, operate more efficiently and reliably, and offer significantly better consumer service.

Society in general benefits from AMI in many ways. One is the improved efficiency in energy delivery and use, producing a favorable environmental impact. A major benefit of AMI is its facilitation of demand response and innovative energy tariffs. During periods of high energy demand, a small reduction in demand produces a relatively large reduction in the market price of electricity. And reduced demand can avoid rolling blackouts.

Together, the utility and its regulators should communicate the full benefits of an AMI initiative to consumers and society at large.

Enhanced functionality can be achieved when the AMI infrastructure sequences into a fully enabled modern grid. When that occurs, EPRI estimates that at least a 4-to-1 total benefit-to-cost ratio will be realized. As described in other Modern Grid Strategy white papers, achieving the vision of the Modern Grid depends on the correct and effective deployment of technologies and applications in 5 key technology areas. AMI supports each of these KTA's.

A May 2007 discussion paper by the Brattle Group estimates that full AMI deployment across the US would cost about $26 billion and that utility operational savings would cover anywhere from 50% to 80% of this cost. It then goes on to estimate a long run generation, transmission and distribution capital savings of $35 billion, along with an additional $5 to 10 billion per year in reduced electricity prices.

The expected benefit/cost ratio is at least 4 to 1. Additional benefits such as improved reliability and power quality, greater consumer choice, reduce environmental impact and others associated with a modern grid should also be considered.

It is clear that AMI provides many benefits to a wide variety of stakeholders, and that going beyond AMI to achieve a truly modern grid produces additional benefits to all, including:

- Greatly improved outage management
- New opportunities for consumer choice and new retail services
- Improvements to power quality

- Virtual elimination of cascading outages, such as occurred August 2003
- Increased national security through deterrence of organized attacks on the grid
- Improved tolerance to natural disasters
- Improved public and worker safety
- Reduced energy losses and more efficient electrical generation
- Reduced transmission congestion, leading to more efficient electricity markets
- Reduced environmental impact
- Improved US competitiveness, resulting in lower prices for all US products and greater US job creation
- Fuller utilization of grid assets and better prediction of when these assets need repair or replacement
- More targeted and efficient grid maintenance programs and fewer equipment failures
- New consumer service benefits such as remote connection, more accurate and frequent meter readings, flexible billing and prepayment services, a variety of rate choices, outage detection, and restoration
- Improved system planning process and results
- Improved mobile workforce management and operations

The MGS publication *Modern Grid Benefits* provides a more detailed discussion of modern grid benefits, including those that accrue to society as a whole.

CALL TO ACTION

The electric power grid is a basic enabler of society, without which our nation would return to a 19th-century economy and life style. America's grid, once the envy of the world, has lost that premier status. The path to regaining that status and to realizing the many associated benefits has been defined by the NETL Modern Grid Strategy and others. Fundamental to this journey is the adoption of AMI across the nation. The benefits of AMI alone are substantial, but when AMI serves as the stepping-stone to a fully modern grid they are increased many fold. Modernizing the power grid must become a national priority, similar to the 20th century program to create a national interstate highway system.

For more information

This document is part of a collection of documents prepared by The Modern Grid Strategy team. All are available for free download from the Modern Grid Web site.

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Acronyms

AAM	Advanced Asset Management
AC	Alternating Current
ADO	Advanced Distribution Operations
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ATO	Advanced Transmission Operations
BPL	Broadband Over Power Lines
CIS	Consumer Information System
CSR	Consumer Service Representative
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
EEI	Edison Electric Institute
EPACT	The Energy Policy Act of 2005
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
HAN	Home Area Network
IP	Internet Protocol
KTA	Key Technology Area
MDMS	Meter Data Management Systems
MWM	Mobile Workforce Management
NARUC	National Association of Regulatory Utility Commissioners
O&M	Operations and Maintenance
OMS	Outage Management System
PLC	Power Line Carrier
PQ	Power Quality
ROI	Return on Investment

RTP	Real Time Pricing
T&D	Transmission and Distribution
TFTN	Turn On Turn Off
TOU	Time-of-use
UE	Union Electric Company (Now Ameren UE)

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[Challenges of Implementing AMI (municipalinfonet.com)]

Challenges of Implementing AMI

by James Ketchledge, General Manager for Projects Enspiria Solutions

Introduction

Successfully implementing Advanced Meter Infrastructure (AMI) capabilities and related Meter Data Management Systems (MDMS) is even more challenging than a typical utility project. While AMI systems are swiftly gaining traction in the industry through regulatory mandates, "green" power initiatives, and pure business case benefits, many of the vendors and technology providers have solutions that are still evolving and are in their infancy compared to more established utility information systems. An AMI project involves much more than selecting a vendor and waiting for the technology to be deployed. AMI projects require utilities to follow an excellent system implementation and integration process due to challenges related to AMI's inherent complex technology, the lack of depth in many vendors' project services, and the integration points across other enterprise IT systems. Therefore, a successful project requires success in three key arenas, Technology, Implementation, and Integration.

Technology Success

An in depth review of success factors related to AMI technology itself must lead to analysis of specific vendor solutions. Therefore, this discussion will be confined to examination of risks that are more general and common among multiple AMI technology providers. The solutions provided by technology vendors continue to expand quickly, driven by regulatory mandates, "green" power initiatives, and pure business case benefits. AMI has been the fastest growth segment of utility spending over the past few years, and the trend is likely to continue or even accelerate as more states follow the lead of Texas, California, and the Ontario province. Such growth translates to heavy investment by vendors, so capabilities are hardly static, and weak points in solution offerings continue to be addressed.

Rapid growth environments attract companies interested in growth and create new ideas, new approaches, and high energy. Most rapid growth environments eventually reach a consolidation point, as winners in the market consolidate the smaller players and absorb niche elements of the solution. The AMI space is no exception, and merger and acquisition announcements have been common for the past year. This growth also places strain on technology companies and even companies with reliable delivery records may begin to show the struggle of multiple, simultaneous implementations and the difficulty in finding people in manufacturing, delivery and services with sufficient skills to support multiple clients.

Issues of scale are also of concern to larger investor-owned utilities (IOU). AMI solutions that work well on a co-op or municipal scale can have issues scaling to million-meter utilities. Communication networks have little issues with scaling, but the head-end is an area of concern if a technology provider does not have existing clients of IOU size.

Therefore, utilities are wise to clearly define their needs in the request for proposal process to a greater degree than normal, and carefully examine the past market success of responders. Time developing detailed requirements up front will eliminate problems down the road. It is also essential to understand the technology provider's development roadmap, and when various capabilities are anticipated to come online, and then monitor that roadmap during project execution. While it is acceptable to have some capability in the "to be developed" category, having more than 10% is clearly a major project risk factor.

Implementation Success

Implementation success for AMI and MDMS projects is much more difficult to achieve than technology success, and should be the focus of a utility about to embark on the AMI journey. Common challenges for AMI projects include failure to meet schedule milestones, failure to meet utility expectations and requirements, poor coordination of necessary implementation tasks, and poor readiness to accept the organizational changes that AMI systems force upon a utility.

Technology providers are companies that supply the AMI system, which generally has three components. These are the smart meters, the communication network, and the software that manages the system and collects data, also known as the "head-end". Many of these companies have evolved from meter manufacturers who then over time offered automatic meter reading (AMR) capability of collecting data from energy or water meters and transferring that data to a central database for billing and/or analyzing. AMI is generally distinguished by the characteristics of fixed communications network and adding two-way communication capability with the meter end point. Further AMI sophistication allows for demand side management through home area networks (HANs). In general, AMI capability and data provides the foundation for the future "smart grid".

Technology providers continue to grow their business by offering project implementation services or system integration capability around their solution. The robustness and maturity of these services can be more important to project success than the technology itself. The hazard for utilities is to under value this aspect of their AMI project. Consistently in our industry, project success is not a given. Studies show that as many as 80% of projects fail to meet their technical, cost, or schedule objectives. Some 30% of projects are cancelled and approximately 50% exceed their original cost estimates. AMI systems are not immune from these metrics.

Project implementation services that are essential for AMI implementation success include project management, system engineering, test engineering, and change management. While each of these services merit in depth discussion, a few major elements and lessons learned in each of these areas are provided below.

Good project management is a key to AMI implementation success. More than other utility projects, AMI project managers (PMs) for both the utility and the AMI vendor need to be seasoned and very experienced due to the system complexity, rapidly evolving technology, and complex integrations with other utility IT systems, including systems responsible for billing. PMs need organizational and operational knowledge, hard and soft project management skills, experience in managing the iron triangle of scope, cost, and schedule, and skills in mitigating risk and guiding the vendor.

Systems engineering is a key partner to project management in ensuring success, and a critical part of system engineering is requirements management which includes an upfront gap analysis, development of more detailed AMI or MDMS requirements, and tracking those requirements through the design process and ultimately the testing and verification process. The requirements analysis allows for a more detailed look at what the system can and can't do, and what are the real capabilities behind the marketing brochures and sales cycle. That analysis has led to significant surprises in AMI deployments, but it is far better to identify any gaps between the initial solution and utility expectations as fast as possible, so corrective action has the least cost and biggest window of time to be fixed.

Another very important part of AMI implementation services is test engineering. A mature test process involves continual verification of the system through gradual build up and deployment and trying to test as much as possible as soon as possible. A “big bang” approach of verifying results too far down the road is a recipe for disaster. Most AMI projects have a field trial prior to full scale deployment, and the field trial’s primary goal is to verify one or more vendors AMI systems ability to achieve the benefits identified by the AMI business case and to meet the functional and performance requirements agreed to in the statement of work (SOW). A secondary goal of field testing is to provide the utility hands-on experience with a vendor’s AMI system. Successful execution of field testing is typically a contract gate for proceeding with mass deployment. Tools that analyze and display system performance data are quite valuable in testing the solution and continue to provide valuable data while deploying the solution, particularly in communication of results and keeping stakeholders in the loop. Figure 1 shows an example of such a test metrics tool, which measures various types of AMI data for availability and accuracy to support the field trial and ultimately deployment.

Finally, change management to ensure organization acceptance is critical. AMI and MDMS projects touch multiple constituencies in a utility, and effective change management facilitates the realization of identified benefits and manages this change. A comprehensive AMI Change Management Plan is needed to mitigate risks and ensure AMI is accepted and that the utility is positioned for long term success. The plan should focus on ensuring that employees can remain productive during the implementation. Successful change management programs start early, communicate frequently even when the answers are unknown, and self-monitor to adjust activities as needed.

Reducing Implementation Risk

The lure of reduced acquisition costs can lure utilities in reducing attention to proper implementation services. Since so much of the cost is in hardware, proposals may offer project management, system engineering, or testing services for a small price or even at no apparent price. It is very important for utilities to perform the due diligence and ascertain the quality of the services that a technology provider has. If the utility does not have the expertise or a proven track record of managing the details of successful implementations, they may want to consider having a consultant who specializes in looking under the covers to assess the maturity and capability of the technology provider implementation and SI services.

Lastly, there are several ways for utilities to reduce their risk in implementing AMI and MDMS. These include verifying the service capabilities of the technology provider in depth at the proposal stage, teaming with the technology provider so that the utility can leverage in house SI capabilities, obtaining SI consultants to monitor or supplement the team, or turn to third party system integration service providers.

Integration Success

Another challenging aspect of AMI projects involves the interfaces and integrations with other utility IT systems. Most implementations initially ignore the valuable integrations between AMI and other utility IT systems. While the core AMI benefits of meter reading and the billing function are clearly critical, planning for other IT integrations early in the project life cycle facilitates ease of unlocking those benefits of an integrated utility IT suite.

Utilities need to independently, or with assistance from third parties, examine integrations because most technology providers have limited or no experience in this area. Integrations with the other utility IT systems such as Customer information Systems (CIS), Geographical Information Systems (GIS), Outage Management Systems (OMS), Work Management (WMS), or Mobile Workforce Management (MWM) have valuable operational benefits.

Enterprise Vision and System Architecture

To ensure integration success, an enterprise vision is necessary and that vision needs to be translated into a concrete enterprise system architecture. That architecture will ensure that the barriers between such disparate systems as AMI, GIS, OMS, CIS, WMS, etc. are broken down thereby increasing operational efficiency. Good enterprise integration allows accurate exchange of information between different systems such that the integration appears seamless and that information residing in any one system can be leveraged by other systems, thereby optimizing business processes.

Utilities at the forefront of smart grid activities are also looking at integration frameworks, such as Enspiria's Enterprise Oriented ArchitectureSM (EOA), that combine dashboards for display of information appropriate by job role, business intelligence, and a graphical capability to promote efficiencies and capabilities that could not be achieved before. This integration framework is extensible and scalable, and provides a common look and feel across the enterprise, as shown in Figure 2.

Integration Priorities

The primary interface for any large scale AMI system is the Meter Data Management Systems (MDMS), and the MDMS forms an integral part of many AMI implementations. MDMS helps the utility process and manage meter operations data as well as meter read data. MDMS provides a single repository for this data with a variety of analysis capabilities to facilitate the integration with other utility information systems. The interface with CIS for billing purposes is through the MDMS, and synchronization between CIS, MDMS, and the AMI head-end is necessary to ensure that premise information, customer information, and billing data is coordinated seamlessly.

The most valuable aspect of integrating AMI into the utility suite is the real-time or near real-time information that AMI provides through interval data. Having interval data provides insight and capabilities that were difficult to achieve before and allows operational improvement that can directly impact utility performance indices. The AMI to OMS interface is a priority since AMI can help significantly to reduce a utility's System Average Interruption Duration Index (SAIDI). Other interfaces allow consumption information to influence system planning and thereby create more efficient distribution networks based on real usage at a resolution of 15 minutes to an hour, and not just monthly reads. Interfaces with GIS allow spatial display of AMI data over a service territory that make can make programs such as theft detection more effective.

Scalable and Extensible Architectures

Utilities should look beyond old point-to-point integrations where possible and embrace techniques that enhance this data sharing between applications. With the revolutionary addition of AMI's real-time information into the utility IT environment, the time is ripe for more scalable and extensible architectures such as an enterprise service bus (ESB) approach that connects individual applications through publishing messages to a bus and subscribing to receive certain messages from the bus. Studies have shown that ESB approaches reduce the cost of new interfaces by much as 50%, and the cost of maintaining that interface by up to 80%.

Summary

The youth of AMI technologies and the associated vendors' inexperience present a risk to implementation that utilities ignore at their peril, particularly given the central nature of AMI systems in the utility revenue stream. A successful AMI project emphasizes the classical system integration skills of project management, system engineering, test engineering, and change management and recognizes that AMI involves much more than selecting a vendor and waiting for the technology to be deployed.

Rather than wait to examine the benefits of AMI integration, an early look at the enterprise architecture and how AMI will fit into it will pay dividends in reduction of functionality gaps and ease of future scaling. The integration of AMI derived real-time data into the enterprise for operations and planning purposes is revolutionary, and utilities that take advantage of it can create real improvements in performance metrics.

Following these guidelines and lessons learned from past implementations, utilities can achieve the ultimate vision of a successful AMI project that meets core business requirements and positions the utility for the smart grid of the future.

About the Author

James Ketchledge*, PMP, is the General Manager for Projects at Enspiria Solutions, where he manages the project management office and directly leads AMI implementation and integration projects. He has 22 years in systems/software engineering and 11 years of project management experience. He holds Masters and Bachelor degrees in electrical engineering.*

Six Steps for Implementing a Secure AMI Infrastructure

by Balu Ambady

EE Online Six Steps for Implementing a Secure AMI Infrastructure (electricenergyonline.com)

September/October Electric Energy T&D Supplement 2015

We live in a connected world, with much of our personal information easily accessible through the tap of a finger or the click of a mouse. This connectivity can improve our quality of life, but with progress comes increased security risks. From medical records to credit card information, if data is available electronically, it is susceptible to an attack. Data breaches can happen to any person, company or industry, and utilities are no different.

More and more public service providers, such as electric utilities, are deploying an Advanced Metering Infrastructure (AMI) to improve operational efficiency, customer service and conserve energy. This combination of smart metering and communications technology can greatly improve operations by giving utilities more insight into their infrastructure than ever before.

AMI systems provide utilities endless amounts of data on a continual basis. While this information can help them address operational issues and streamline efficiencies, it is imperative that utilities are properly safeguarding this data from potential data breaches. That's where data security comes into play. For electric utilities, before beginning an AMI deployment, you should start with a clear plan for making security a top priority to give your customers the best possible protection against cyberattacks.

Protect the Keys to Your Kingdom

Your utility has decided to deploy an AMI network. Now, you must make sure your infrastructure is secure. Here's a 6-step plan to secure your network and protect your customers' data:

Step 1: Create a governance framework

To make security a top priority for your organization, you will need senior level, corporate support for the program. Clearly defined roles, responsibilities and accountability, combined with proper auditing and reporting allows for adequate risk management. While engineers and system administrators provide a wealth of knowledge and expertise for implementing security measures, senior management must back a company culture that requires every employee to comply with the security policies. Security governance and security management programs help align information security strategy with business objectives and compliance requirements, while helping manage risk. This will leave less room for hackers to find an alternate route into your system or for employees to make innocent mistakes that can harm the security of your network.

Step 2: Develop clear policies and procedures

Once you have strategic oversight through the governance and management framework, you need to develop controls that will cover all aspects of your AMI system security, typically designed to protect Confidentiality, Integrity and Availability (CIA). While you strive to obtain company-wide support and compliance for your security program, it is crucial to develop high level policies clearly defining roles and responsibilities for security management and listing the rules and controls required for network access. You policies also need to be supported with standards and guidelines that detail mandatory and non-mandatory controls. These are supported by procedures that cover step by step instructions for implementation, for example specific operational steps for setting up firewalls, handling the encryption keys or performing backups. A security awareness and training program rounds this out. These steps will help protect your organization, and in the event of a problem, you'll know how to address the issue.

Step 3: Develop and Implement a deployment plan

Proper planning is required to make sure that deploying security controls during your AMI deployment goes smoothly. Working with your AMI vendor, a security assessment helps you identify all assets that need protection, as well as potential threats to your network. For each threat, risk assessment and risk prioritization leads to the development of an actionable plan for secure deployment. Several of the following technologies may be implemented to help you design and deploy a layered defense for your AMI network.

Your demilitarized zone (DMZ)

DMZs with dual firewall architecture provide a layer of security to your organization's network by tightly regulating traffic entering and exiting your network. A DMZ network usually contains three zones, a trusted zone (Internal), a DMZ (Less Trusted) and an External Zone (Untrusted). When deploying your AMI servers, they can be integrated with your existing DMZ network. Typically, the AMI head-end server(s) resides in the DMZ behind the perimeter firewall, while the AMI database and other AMI components reside in a more trusted zone that is separated from the DMZ by the back-end firewall. Other remote components of the AMI system such as Collector/Gateways may be configured to securely communicate with the AMI head-end server over virtual private networks (VPN).

Set up role-based access control

On all the servers that will be part of your AMI network, make sure they are controlled through role-based access control, or RBAC. This is an approach to restricting access to authorized users based on the role of the individual. Operations on the AMI servers are assigned to specific roles, and the RBAC restricts access based on permissions associated with each role. For example, different roles may be assigned for users responsible for managing smart meters versus administrators.

Secure remote access with multifactor authentication

Administrators and other users may require remote access to your systems. The more secure method for your remote users to access your system is using multifactor authentication (MFA). Using only usernames and passwords has drawbacks, for example, users may choose easy to guess passwords for their login, which can pose major security threats to your AMI network. MFA is a security system that requires more than one method of authentication from varying categories of credentials to verify a user's identity. For example, remote users may be prompted to use an entry code generated on a security token in order to access the system in addition to their username and password. This is a more secure method for remote entry and can greatly reduce the attack surface compared to using only username and passwords.

IDS and IPS for your AMI

Creating a properly protected network, including careful placement of intrusion detection systems (IDS), and Intrusion Prevention systems (IPS), is critical to safeguarding against cyberattacks. These technologies should be placed at critical ingress or egress points within the network to ensure maximum coverage of traffic. In addition to network protections, Host Based IDS/IPS software should be deployed on AMI systems to provide additional layers of security against local system threats. During the configuration of all of these technologies you should make sure that the auditing and logging are properly enabled, along with continuous monitoring and recording of all events to alert on suspicious activity.

Encrypt AMI network traffic

When you are deploying an AMI system, it is critical to enable encryption on all relevant portions of your network. Encryption is the process of encoding messages or information in a way that only authorized users with encryption keys can access it. Should someone break into your communication system, message encrypting prevents the interceptor from reading your information. By encrypting network traffic on all parts of your AMI network, you will protect your system all the way from the end points (electric, water or gas meters) to the head-end system.

Create redundant communication channels
In addition to enabling encryption on your communication network, make sure that your communication channels have redundancy with multiple paths. This protects from denial of service (DOS) type cyberattacks. Your AMI communications networks should be designed so that all endpoints, such as electric meters, can communicate with more than one collector. This way, if a certain collector is taken down (either for regular maintenance or due to a cyber- attack), your endpoint communication with the head of the system can still continue without interruption.

Secure Configuration and Patching
From the very start of your AMI network deployment, make sure that all systems are properly configured to reduce exposure. During configuration, make sure that the underlying operating system, as well as any applications and additional software is securely configured and hardened to prevent intruders from accessing AMI information. In addition, these systems also need be continuously updated with latest software patches and hot fixes from the operating system and application vendors.

Step 4: Test and re-test before roll-out
After you have built up your secure AMI network, make sure that you test and re-test before rolling out your system to your customers. Start by testing in the lab to make sure there are no bugs or errors. Once you have fixed any errors found during your testing, it is recommended to do a small pilot with a few hundred endpoints. This will help you see how your system performs in the field, while keeping the program at a smaller scale so you can resolve any issues before a mass deployment. Once you feel comfortable with the performance and adequacy of your security during the pilot, you can deploy in larger numbers until you have deployed the system to all of your customers.

Step 5: Schedule regular maintenance
While your system may have been secure when you first implemented it, you should also schedule time for regular maintenance and patching to keep it secure. Have an operations team whose sole job is maintaining the security of your AMI system conduct routine maintenance checks. To get the most out of your technology investment, schedule regular updates, patching and maintenance on a monthly basis.

Step 6: Get third-party pen-tests and reviews
You may think you have secured every possible entryway into your AMI network, but it is still important to get a second or even third pair of eyes to review your work. There are third-party reviewers and penetration-test venders who specialize in checking the security of your system. Consider conducting an annual or bi-annual pen-test, especially if you are going through major system changes. These experts can look at your system security to identify weaknesses and give recommendations on ways to improve upon your program.

There are many moving parts in an AMI deployment, but it is critical to not let security fall to the wayside. Following an organized security plan can greatly cut down on confusion and miscommunication during this process, helping you derive benefits from your AMI system faster.

Find a Trusted Partner
AMI is an extremely useful technology because it helps utilities improve their operations and provide customers with more insight into their energy use. However, the threat of data breaches is growing. To reap maximum benefit from your network, it must be secure. This is why it’s important to use multiple levels of defense that can be employed to significantly reduce your risk.

If you are at a loss for where to begin when connecting your network, you can also partner with a communications company to securely host your network. This can be especially helpful for smaller utilities who do not want to invest the additional capital in IT, office space and specialized employees. A trusted partner will monitor your servers and network connections around the clock, provide software patches and updates, and ensure that you have access to the latest features.

Because your utility's main job is to provide customers with a reliable service, it is important to find partners who can defend your network. Having this trusted partner can make the difference when fending off viruses, hackers, or securing against innocent mistakes. You can rest at ease knowing the data you and your customers' rely on is secured.

About the Author

Balu Ambady is the director of security for Sensus. As an information security leader with more than 20 years of experience, he has expertise in creating advanced security infrastructure and developing security compliance programs. Prior to joining Sensus, Balu served as the director of advanced technology and security for CableLabs where he managed the design and development of video architecture and security. Balu is a Certified Information Systems Security Professional and Certified Information Security Manager.

Strategies to Consider When Implementing AMI

Bill Zorn, Electronic Data Systems (EDS) Energy Industry Executive

Electric Energy Magazine, March/April 2006 Edition

Change is a constant state in the world today. Utilities are facing changes on a scale they have not faced since the 1900s. New technologies, merger and acquisition activities and government regulations all mean significant change for utility companies. A number of utilities are looking at implementing advanced metering infrastructure (AMI) as a way to improve overall business operations as well as meet the Energy Policy Act of 2005 (EPAct) mandating "energy efficiency" on all levels.

Sometimes referred to as "smart meter" or "automated meter reading," AMI is simply the use of digital technology to collect, synthesize and report data for billing purposes rather than the former labor-intensive, manual methods.

It allows utility companies constant two-way communication with their commercial, industrial and residential meters, which is essential for improving customer service, reducing operational costs and positioning for growth.

EPAct 2005 is creating even more pressure for utility companies. The act, signed in August of 2005, provides utility companies with incentives to improve traditional energy production, as well as find new and more efficient energy technologies to meet the long-range conservation effort. EPAct will force many utilities to transform metering and demand response systems, but the key will be to develop a long-term strategy on an adaptable infrastructure.

Although AMI is not a new idea within the industry, it is very much top of mind for many utility companies today. Although implementation costs may be high, the benefits of managing meters remotely far outweigh the price tag to implement an AMI solution.

The Benefits of AMI are Evident

Even though AMI was developed more than 10 years ago, the demand for "energy efficiency" by both the government and consumers is making it a reality. It is truly becoming the most effective way for utilities to replace the sometimes inaccurate, labor-intensive process of physical meter readings. This, combined with diminishing natural resources and a need to reduce operating costs, has made AMI an important consideration for future operations. In fact, many states are pushing utilities to offer consumers more options for reducing overall power consumption.

The following is a snapshot of the benefits that have been identified and well-documented for implementing AMI:

• AMI improves the process of managing demand for natural resources allowing the utility to offer consumers incentives for selective load control.

• Making educated assumptions about future usage is the most imperative data collected by AMI. It provides information about factors that stimulate peak consumption, which can be translated into business strategies such as proactive load management, outage prevention and consumer incentive programs.

• It also enables utilities to implement pricing structures that offer incentives for efficient energy users, so peak energy users are charged more and efficient users no longer subsidize inefficient users. By monitoring almost real-time usage, utilities can ultimately help customers save money on their utility bills.

• Automated, remote data collection streamlines back-office processing for billing, asset management and outage management. The automated data transfers improve meter reading accuracy which ultimately reduces customer complaints.

• AMI reduces the number of steps between consumer usage and bill distribution, so utility companies yield cost savings by significantly shortening their billing cycles.

• Rather than customers having to call in and experience long hold times, AMI can proactively provide customers with information regarding outages. Another way call center activity and related costs are greatly reduced is decreased data entry errors, which in turn reduces billing errors and customer disputes, thus reducing customer calls.

• AMI technology offers utility companies valuable insight into customer usage, including consumption behavior, effects of external variables and outages. Data collected at 15-minute intervals can be used for profiling usage, time-of-use data, demand management and phase-load balancing. The overall results are improved quality of service and shortened response times to outages.

The benefits of AMI can be seen in all areas of the supply chain. Automation alone can lower costs related to billing, meter reading, call center activity and demand response. However, the risks associated with a large-scale deployment of AMI are considerable.

Despite these risks, utilities are being forced through competitive and regulatory pressures to deploy AMI systems. It is important for utilities to understand the risks involved, in order to minimize them, while maximizing their return.

AMI's Biggest Risks

Initial Capital Outlay and its Effect on Cash Flow
A major risk utility companies contend with when implementing the new infrastructure is the amount of capital required and the subsequent effect on the utilities' cash flow. AMI usually requires a large capital expenditure initially for the meters, data concentrators and the labor to install them, as well as the software, hardware and communications required to run the system. That expenditure can decrease if there is a rate increase approved to support it, but cash flow is still an issue.

Potential Interruption and its Effect on Revenue

More importantly, utilities cannot afford to stop or even slow down operations for a new implementation. Since meters directly impact a utility's revenue, the risk of changing technologies and processes means shutting down the utility's source of collecting that revenue. The implementation can also be a drain on "people resources" because there is usually a small army of key utility staff members devoted to the project.

Some problems are inevitable in any large implementation, but there are ways to control costs associated with the implementation of a new infrastructure.

Strategies to Address AMI's Risks Metering Technology

The bad news is the AMI technology, including meters, concentrators, and head-end systems, is the largest cost component of a large deployment. Experience tells us this cost category is usually 35-40 percent of the total cost of deployment.

The good news is, in the long-term, this digital technology will continue to improve in functionality and decrease in cost. Take the evolution of personal computers costs as an example. When PCs first came out in the early 1980s, they cost at least $10,000. There were a number of proprietary hardware components that were unique to each manufacturer. Today, good PCs can be purchased for less than $500 with a magnitude of functionality far greater than their predecessors and are now equipped with mostly interchangeable components.

Digital metering technology will evolve in the same way, so metering technology should be treated as commodities. Utility companies should recognize there will be multiple metering systems as a result of geographical or topological concerns, as well as realize metering technology will continue to evolve and improve functionality. The metering technology implemented in the beginning will not be the same at the middle or end of the implementation. As a result, it is best for utility companies to not get tied to a particular metering vendor or pay for another utility's deployment by purchasing its metering solution. Utility executives should buy from a reputable meter manufacturer that meets the company's functionality needs at the lowest cost.

Networking Solutions

The key is to evaluate different local area networking (LAN) solutions for different population densities. There are several good LAN technologies. For example, PLC, RF and RF-mesh are currently available and more, such as BPL, are coming. Each has different technology issues and costs to consider.

PLC technology is great for rural and urban areas with large buildings. RF-mesh solutions are extremely cost effective for suburban areas. Most utility companies will need to use a mix of these technologies in order to minimize the LAN networking costs.

On the other hand, Wide Area Networking (WAN) costs are commodities and should be treated as such. Utility companies should not get locked into long-term contracts with communications companies. Prices will continue to drop. The concentrator technology chosen must have the ability to use different modems, including phone, cellular, even satellite, and be replaceable when the price is right.

Meter Data Management

Meter Data Management (MDM) is the most important part of the architecture when aiming to keep costs low. A meter data management system that runs on multiple architectures, such as Windows, UNIX, and Linux, must be selected. It is best to purchase a MDM system from a company that does not make meters – unless the plan is to use only one type of metering system for the entire deployment (please refer to the above section on "Metering Technology" explaining why agility is important).

An independent software house usually has more incentive to be open to communicating with any meter manufacturer's head-end system. Also, installing the meter data management system before any meters are deployed will allow utility companies to input current manual or handheld readings. It is imperative to then build interfaces to production systems so when the first AMI meter goes into production, the business benefits are realized immediately.

Additionally, the system must be scalable enough to handle the current and future meter population such as growth resulting from merger and acquisition activities. The MDM system chosen must also have a track record of success – the utility's future should not be dependent upon a product that has not been tested widely in the marketplace.

Legacy System Interfaces

An enterprise application integration (EAI) tool should be utilized if it has already been established – especially for all near real-time and real-time interfaces. Large volume interfaces, like billing systems, should still use batch interfaces. If an EAI tool has not been put into operation, utility companies should consider installing one in conjunction with the AMI deployment. In the long run, it will save time in coding and related costs.

There are several good EAI tools in the marketplace today and each has a slightly different set of advantages – but AMI should not drive the decision regarding which EAI tool is chosen since many are highly adaptable for easy use with AMI. An EAI tool should be selected because it meets the enterprise-wide objectives and needs.

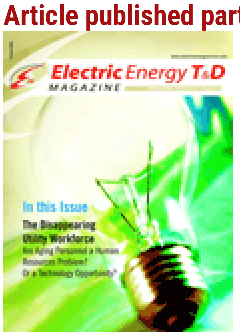
Additionally, the overall project management aspect, from beginning to end, is critical to AMI success at a utility company. Whether the company chooses to implement AMI in-house or through a service vendor, it is imperative a master plan, including the IT blueprint, is in place and the executive management is committed to that plan and understands the enterprise-wide benefits.

In summary, utility companies deploying AMI will certainly face risks. Employing some of the strategies noted above can help minimize those risks and help utilities reap the advantages of implementing AMI.

About the Author

EDS Energy industry executive Bill Zorn specializes in Advanced Metering Infrastructure (AMI). With more than 28 years of delivery, sales and consulting experience in systems and services, Zorn is considered a subject matter expert in Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI). In addition to his expertise in the energy industry, he has considerable expertise in the manufacturing industry as well as experience in corporate and divisional business planning, management, sales, delivery and consulting.

Article published part of the March/April 2006



A Summary of "Useful Life" Values for Smart Electric Usage Meters

(as documented in various utility industry-related documents/ web links worldwide)

Compiled by SkyVision Solutions
September 2018

The information in this document is provided to substantiate the claim that most electric utilities and supporting companies tend to claim that smart meters have a useful life of 15 to 20 years. There is reason to believe these numbers are overly optimistic based on evidence available from other sources as documented at https://wp.me/p3nav9-4b7

Source Document or Link	Smart Meter Useful Life (as quoted from source)
Testing Expert Tom Lawton from TESCO in a 2014 slide presentation (slide 5) available at: http://www.slideshare.net/bravenna/meter-operations-in-a-post-ami-world-36336258?related=1	"Electronic AMI meters are typically envisioned to have a **life span of fifteen years** and given the pace of technology advances in metering are not expected to last much longer than this."
"Ameren Illinois Advanced Metering Infrastructure (AMI) Cost/ Benefit Analysis," June 2012; available at: http://wp.me/a3nav9-3VW	"With respect to meter depreciation, Ameren Illinois has reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to base its AMI deployment on a **useful life of 20 years** for the AMI meter."
"ComEd Files Smart Meter Deployment Plan," April 2012, Press Release; available at: http://wp.me/a3nav9-3sR	"[E]fficiencies could save customers $2.6 billion over the **20-year life** of the smart meters, according to a cost-benefit analysis by Black & Veatch, a consultancy that evaluated operational cost savings as part of the plan that was filed with the ICC."
Naperville Smart Grid Initiative Question Response Inventory, dated 25 March 2013, page 36 of 77; available at: http://wp.me/a3nav9-3T3	"The smart meters are manufactured by Elster and are expected to have a **life of roughly 15-20 years**. At that time they will be replaced by the city on a rolling basis."
Fortis BC November 2012 Letter pertaining to Revised Response to British Columbia Utilities Commission (BCUC or the Commission) Information Request; available at http://wp.me/a3nav9-3VX	"Meters – Assumptions regarding depreciation rates for the AMI meters have been determined based on the **observed useful lives** as established through industry experience, as well as through the manufacturer's recommendations. This has resulted in a 5 percent depreciation rate based on an estimated **economic life of 20 years**;" … "Itron has provided written confirmation of the **expected 20 year life** of the proposed AMI meters."

Source Document or Link	Smart Meter Useful Life (as quoted from source)
BC Hydro Media Release on Smart Meters, January 2016; see response to question, "How long do the new meters last?" at https://www.bchydro.com/news/press_centre/news_releases/2016/why-we-may-need-to-exchange-some-meters.html	"New meters have a **minimum life expectancy of 20 years**."
Southern California Edison (SCE) AMI Preliminary Cost Benefit Analysis, December 2006; available at http://wp.me/a3nav9-3VY	"The analysis period is dictated by the multi-year deployment schedule that begins in 2009, and by the **20-year useful life** of the meters."
Echelon MTR 5000 Series ANSI Smart Meters, specification datasheet, at http://www.echelon.com/assets/blt6b8a91498df28864/Smart-Meter-MTR-5000-ANSI-datasheet.pdf	"**Life Expectancy: 20-year design**."
"2012 AMI Business Case Update," Seattle City Light, March 2012.	"The SAIC AMI business model supports several methods for calculating depreciation. At City Light's request, depreciation is calculated utilizing a straight line method over 15 years. **The actual life of the AMI equipment may be 20 years or longer.** Alternatively, it may be replaced sooner if newer technologies and functions emerge that constitute a compelling reason to change operations. **The assumed 15 years is typical of current utility practice**."
Notice to Public Service Company of New Mexico Customers regarding AMI deployment proposal April 2016; available at http://wp.me/a3nav9-3W4	"It is reasonable to recover the undepreciated investment in existing meters over a twenty year period in order to properly balance impacts on customer rates and timely recovery of the undepreciated investment. **The twenty year recovery period is consistent with the expected useful life of AMI**."
Direct Testimony of Henry E. Monroy, New Mexico NMPRC Case No. 15-00312-UT, February 26, 2016, page 4.	"WHY WAS THE COST-BENEFIT ANALYSIS PERFORMED OVER TWENTY YEARS? … The time period selected was based on the expected **useful life of the AMI meters**, which is **20 years**."

Source Document or Link	Smart Meter Useful Life (as quoted from source)
Michigan Public Service Commission Staff Report, June 2012 regarding smart meter proposed costs and benefits; available at http://wp.me/a3nav9-3W0	"Consumers Energy Estimated savings over the **anticipated 20-year life of the smart meters** is $2 billion."
Arizona Public Service (APS)'s Response to Arizona Corporation Commission (ACC) Staff's Ninth Set of Data Requests, October 2016; available at https://wp.me/a3nav9-4aP	"APS is proposing a **20-year useful life** for both AMI and non–AMI meters in the 2016 depreciation rate study."
Direct Testimony of Paul Alvarez on behalf of the Office of the Attorney General for the state of Kentucky, May 18, 2018; available at https://wp.me/a3nav9-4aN	**See table below (page 4)**. SkyVision Solutions did not independently verify all values listed by the Paul Alvarez. The last line in the table pertains to Kentucky, the subject of the testimony, and for which the final value submitted to the Kentucky PSC was 20 years. *****
Public Service Commission for the Commonwealth of Kentucky, Case No. 2018-00005, Order pertaining to Deployment of Advanced Metering Systems for Louisville Gas and Electric Company & Kentucky Utilities Company; available at https://wp.me/a3nav9-4aO	"In support of their assertion that the meters have a **20-year service life**, the Companies relied upon a two-word email from their vendor that read '20 years' in response to a question about the expected service life."

* Refer to the table on the next page (page 4) for a summary of smart meter benefit periods documented as part of a rate proceeding in the state of Kentucky.

Benefit Periods for Publicly Available Smart Meter Business Cases

IOU	State	Docket	Year	Benefit Period	Customers (millions)	Regulatory Approval?
Eversource	MA	15-122	2015	15	1.20	No
Massachusetts Electric	MA	15-120	2015	15	1.32	No
San Diego Gas & Electric^	CA	R08-12-009	2011	15	1.43	Yes
Ameren	IL	12-0244	2012	20	1.22	Yes
ComEd	IL	12-0298	2012	20	3.95	Yes
ConEd	NY	15-E0050	2015	20	3.40	Yes
Duke Energy Ohio*	OH	08-920-EL-SSO	2008	20	0.69	Yes
Duke Energy Carolinas	NC	E7 Sub 1146	2017	20	1.95	TBD
Pacific Gas & Electric	CA	R08-12-009	2011	20	5.43	Yes
KU/LGE	KY	2018-00005	2018	23	0.92	TBD

^ "Terminal Values" (to account for benefits beyond 15 years) also provided for information purposes.

* While a 20-year useful life was assigned to smart meters, the associated communications network was assigned just a 10-year useful life.

Source: This Table was included as Part of Direct Testimony for Paul Alvarez on Behalf of the Office of the Attorney General for the state of Kentucky, May 2018.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 3

Date Request Received: 7/12/23 Date of Response: 7/26/23
Request No. DOE 3-2 Respondent: Anthony Strabone

REQUEST:

Reference Testimony of Anthony Strabone at Bates 301: "Although the Company's reliability targets are approaching the first quartile, there are signs within the electrical system that are experiencing poor reliability."

a. Please explain the significance of first-quartile performance.

b. Please explain what "poor reliability," performance means in the context of system planning and capital project prioritization, and if this is typical system performance from year-to-year.

c. Please explain why the requested Reliability Projects growth budget is increasing from $3,790,000 in 2023 to $6,210,000 in 2024. (Reference DE 23-039, Attachment 1604.01(a)(23), Bates 180.)

RESPONSE:

a. The electric power industry, led by the Institute of Electrical and Electronics Engineers (IEEE), has determined that the best overall measure of an electric utility's reliability correlates to a utility's reliability metrics such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Utilities report their SAIDI and SAIFI numbers to the U.S. Energy Information Administration (EIA), which creates a ranking system based on SAIDI and SAIFI allowing electric utilities a way to benchmark their reliability performance against Industry peers. The significance of first-quartile performance indicates that the Company has reliability metrics, SAIDI & SAIFI, that are approaching the same values of the top 25% of its Industry peers.

b. "Poor reliability" refers to a situation in which an electric system or grid experiences frequent and prolonged service interruptions, resulting in unreliable power supply to customers. Improving poor reliability is an objective when performing system planning, identifying, and prioritizing capital projects. When reviewing reliability performance of the electric system, the Company will also look at Circuit Average Interruption Duration Index (CKAIDI) and Circuit Average Interruption Frequency Index (CKAIFI) to determine if there are any circuits and/or smaller pockets/areas on these circuits that have poor performance. The Company continuously monitors this information and circuits that have poor reliability year over year will be identified as a 'worst performing feeder' whereas a smaller pocket/area of these circuits will be identified as 'pocket of poor performance.' Once a worst performing feeder or pocket of poor performance has been identified, the Company will identify a project to address the issues causing poor reliability.

c. Please note the correct page reference for this information is Bates I-178 from the Company's May 5, 2023, filing, not Bates 180. As mentioned in part b of this response, the Company continuously monitors the reliability performance of the electric system and recommends capital projects based on this performance. The reason for the increase in Reliability Project growth budget between 2023 and 2024 is to address specific Reliability Projects that the Company has identified based on performance. These projects include, but are not limited to, replacement of bare conductor with tree resistant wire in spacer cable configuration and replacement of direct buried underground residential cable with current installation standard which includes underground wire installed in a conduit system. By investing in these projects, the Company aims to improve the overall reliability of the electric system and deliver safe and reliable power to its customers.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23
Request No. DOE 6-23

Date of Response: 9/15/23
Respondent: Heather Green

REQUEST:

Reference Attachment DOE 3-5: VMP Project Rate Years Spending.

a. Provide a detailed breakdown of the cost components that comprise the Planned Cycle Trimming line item. Specifically, breakout the cost associated with increasing the size of the trimming box.
b. Describe the role and responsibilities of the work planners, number of individuals, who they work for, and who they report to.
c. Explain why the work planners' cost was increased under the "2023 Budget (Full Services)" (column D).
d. Provide a typical field plan and report a work planner provides to Liberty as part of their responsibility.

RESPONSE:

In preparing this response, the Company identified that the May 5, 2023, filing contained an erroneous schedule and definitions on Bates pages II-572 through II-575. In the Company's response to DOE 1-1, specifically Attachment DOE 1-1.5.xlsx, the Company provided an attachment revising the schedule on Bates II-572, however did not clearly identify that the Company provided a revised schedule. The original schedule as filed on Bates II-572 was missing a line for Program Assessment of $66,384 in 2025 ($33,192 in Rate Year 1 and $33,192 in Rate Year 2) and contained outdated program names and definitions.

In the Company's response to DOE 3-5, the Company provided an attachment in the response that referred to the original schedule as filed on Bates II-572.

With this response, the Company is providing Attachment 23-039 DOE 6-23.1 containing the revised Rate Years 2 and 3 VMP plan to reflect the Program Assessment line and as provided in Attachment DOE 1-1.5 as well as a revised program definitions updating what was originally filed on Bates II-573 through II-575.

Docket No. DE 23-039 Request No. DOE 6-23

a. The Cycle Trim (Planned Cycle Trimming) line item per Attachment 23-039 DOE 6-23.1.xlsx, line 18, is comprised of only one (1) item. It reflects the estimated tree contractor lump sum bid cost to perform routine tree trimming on the designated mileage as listed in line 11 (# Miles). These costs were estimated based on historical cost per mile with a 10 percent adder per year. The Company acknowledges that fluctuations in the supply chain and the labor market make it very difficult to estimate future costs and has proposed a full annual reconciliation of these costs.

   A specific breakdown of the cost associated with increasing the size of the trimming box does not exist.

b. The plan includes three arborists or work planners. Two of the work planners are responsible for pre-planning the work at a property and span level to provide an executable work plan to the tree crews. Responsibilities also include property owner notification and permissions for tree trims/removals where required and auditing the completion of the tree work to ensure contract compliance.

   One work planner is responsible for process implementation and improvements, data integrity, Terra Spectrum Field Note build and support, support of invoice processing, quality control, assisting in auditing, training, work coordination, and more.

   In addition to the duties described above, the work planners support the vegetation management program in any way needed, depending on the needs of the program. These duties include investigation of tree-related interruptions (to provide guidance on future tree removal priorities), customer service needs, verifying safe tree crew practices, risk tree evaluation, data entry, data validation, coordination of joint work between the vegetation department and other entities, scenic road work requests and town hearings, assistance to tree crews with data entry, and data entry software training.

   The three work planners are contracted, external resources that report to the Manager of Vegetation Management for Liberty.

c. The "Full Services" in column (e) in Attachment 23-039 DOE 6-23.1.xlsx refers to the cost to fully fund the program per the Company's estimate. Column (d) refers to how the company budgeted programs and resources to achieve the $2.4 M agreed-upon budget. The increase from the budget established in the previous rate case now reflects the Company's estimate to provide full services.

d. The work planners identify the work that needs to be performed and write the work order for the crews to execute the work. There are no specific "Work Planners reports," there are only work orders that the work planners write up according to their review of the work needed to be done.

   See Attachment 23-039 DOE 6-23.2 for a demonstration of the type of instructions/advice provided by the work planners to Liberty and the vegetation management crews as previously provided in response to DOE TS 1-2 in Docket No. DE 21-138.

Revision to Bates II-575, Attachment HG-4

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
1																									
2																									
3																									
4																									
5																									
6																									
7																									
8						Bridge Period		Rate Year 1				Rate Year 2				Rate Year 3									
9					Escalator	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
10	Vegetation Management	Vegetation Management (VM)		5 Yr																					
11	# Miles	# Miles	165.09	175.00		41.27	41.27	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75						
12	Type of Work Attachment 23-039 DOE 3-5	Type of Work Attachment 23-039 DOE 1-1.5	2023 Budget ($2.4M)	2023 Budget (Full Services)	Annual Escalator	2023 Q1 Budget	2023 Q2 Budget	2023 Q3 Budget	2023 Q4 Budget	2024 Q1 Budget	2024 Q2 Budget	2024 Q3 Budget	2024 Q4 Budget	2025 Q1 Budget	2025 Q2 Budget	2025 Q3 Budget	2025 Q4 Budget	2026 Q1 Budget	2026 Q2 Budget	2026 Q3 Budget	2026 Q4 Budget				
13																									
14	Work Planners for Veg Plan	Cycle Administration	$220,000	$375,000	5%	$55,000	$55,000	$93,750	$93,750	$98,438	$98,438	$98,438	$98,438	$103,359	$103,359	$103,359	$103,359	$108,527	$108,527	$108,527	$108,527				
15	Spot Tree Trimming	Spot Work	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
16	Trouble and Restoration Maintenance	Trouble and Restoration Maintenance	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
17	Interim Trimming	Interim Trimming	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
18	Planned Cycle Trimming	Cycle Trim	$1,435,663	$1,418,025	10%	$358,916	$358,916	$354,506	$354,506	$389,957	$389,957	$389,957	$389,957	$428,953	$428,953	$428,953	$428,953	$471,848	$471,848	$471,848	$471,848				
19	Police Detail Expenses - Cycle Trimming & Other	Traffic Control	$324,836	$607,099	5%	$81,209	$81,209	$151,775	$151,775	$159,363	$159,363	$159,363	$159,363	$167,332	$167,332	$167,332	$167,332	$175,698	$175,698	$175,698	$175,698				
20	Hazard Tree Removal	Fall-In Risk Tree Removals	$50,000	$437,500	5%	$12,500	$12,500	$109,375	$109,375	$114,844	$114,844	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
21	Hazard Tree Removal - Catch up	Grow-In Risk Tree Removals	$0	$437,500	5%	$0	$0	$109,375	$109,375	$114,844	$114,844	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
22	Brush & Limb Lead Removal	Brush & Limb Lead Removal	$0	$135,200	5%	$0	$0	$33,800	$33,800	$35,490	$35,490	$35,490	$35,490	$37,265	$37,265	$37,265	$37,265	$39,128	$39,128	$39,128	$39,128				
23	Tree Planting	Tree Planting	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
24	IVM/ Herbicide in ROW	ROW IVM Sub-Transmission Herbicide	$69,210	$69,210	Specific	$17,303	$17,303	$17,303	$17,303	$15,000	$15,000	$15,000	$15,000	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250				
25	Polinator Education/Habitat	ROW IVM Pollinator Education/Habitat	$5,000	$5,000	5%	$1,250	$1,250	$1,250	$1,250	$1,313	$1,313	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
26	Monarch Butterfly Conservation	ROW IVM Monarch Butterfly Conservation	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
27	AI- Dash Software	VM Software AI- Dash	$42,000	$42,000	5%	$10,500	$10,500	$10,500	$10,500	$11,025	$11,025	$11,025	$11,025	$11,576	$11,576	$11,576	$11,576	$12,155	$12,155	$12,155	$12,155				
28	Mailers/ Permissions	Printed Material	$3,500	$5,000	5%	$875	$875	$1,250	$1,250	$1,313	$1,313	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
29	Permit Fees	Permit Fees	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
30	Terra Spectrum	VM Software Terra Spectrum	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
31	Training	Training	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
32	Sub-Transmission Right of Way Clearing	ROW IVM Sub-Transmission Clearing	$0	$80,000	5%	$0	$0	$20,000	$20,000	$21,000	$21,000	$21,000	$21,000	$22,050	$22,050	$22,050	$22,050	$23,153	$23,153	$23,153	$23,153				
33	Make Safe Removals	Make Safe Work	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
34		Program Assessment	$0	$0	5%	$0	$0	$0	$0	$0	$0	$0	$0	$16,596	$16,596	$16,596	$16,596	$0	$0	$0	$0				
35	Total VMP O&M Expenses	Total VMP O&M Expenses	$2,419,709	$3,923,363		$604,927	$604,927	$980,841	$980841	$1,044,441	$1,044,441	$1,044,441	$1,044,441	$1,118,256	$1,118,256	$1,118,256	$1,118,256	$1,178,129	$1,178,129	$1,178,129	$1,178,129				
36																									
37	Calendar Year	Calendar Year						CY23	$3,171,536			CY24	$4,177,762			CY25	$4,473,026			CY26	$4,712,514				
38								RY1	$4,050,563			RY2	$4,325,394			RY3	$4,592,770								
39		Bridge period spending = 50% of allowed rates ($2.2M) + 10% overage = $1.21M																							
40		Assumes a reset of trim cycles - no catch up of deferred miles																							
41		Assumes a 5 year trim cycle consistent with Puc 307.10																							
42		Assumes full reconciliation of vegetation management costs through the Revenue Adjusment Charge (RAC) - actuals compared to forecasted rate year																							

Brush & Limb Lead Removal (Planned)
This captures all charges for removal of 4.5”-8.5” diameter* trees or limb leads 8.5” diameter or greater on the system typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5931

Cycle Administration: (Planned)
This captures the activities around the work planning and administrative processes. Work planning is a systematic approach to prescribing vegetation maintenance work around power lines. It involves the patrol and inspection of the power line corridor on a span-by-span basis. Work planning begins with an experienced (and typically degreed) forester working as an inspector (work planner). The clearances and tree selection parameters are pre-determined by the utility and are applied to the field conditions. Work is recorded in a software management system and assigned. The prescribed work is executed by the line clearance contractor. The work planning process concludes with a review of the work by auditing. Additional administrative responsibilities include, but are not limited to: process implementation and improvements, data integrity management, Terra Spectrum Field Note build and support, support of invoice processing, quality control, assisting in auditing,providing training, p[roviding work coordination and more.
DNH.VEGMGNT.VM.1000

Cycle Trim: (Planned)
This captures charges for annual fiscal year of obtaining permissions and execution of planned cycle pruning, brush cutting, clearing and vine removals activities but does not include police detail expenses, removals 5” in diameter or greater or work planning.
DNH.VEGMGNT.VM.1215

Enhanced Risk Tree Removal (ERTM): (Planned) (Not in current budget. Placeholder for future.)
Captures all charges for the hazard tree removal program directed at improving reliability of on and off cycle poor performing circuits based on removing dead, dying and/or structurally weak trees, limbs and leads on the three phase portions of those targeted circuits using a Customer Served approach beyond each major reliability device point including the lockout section or station breaker to the first reliability device.
DNH.VEGMGNT.VM.1220.5933

Fall-In Risk Tree Removals (Planned)
This captures all charges for removal of fall-in (mostly growing outside the corridor) risk related dead, dying and/or structurally weak trees, limbs and leads typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5933

Grow-In Risk Tree Removals (Planned)
This captures all charges for tree removals growing within the corridor typically performed with cycle work. However, may be performed off cycle as catchup. Typically, the diameter is 8.6” in diameter or greater. Removal of these trees helps establish the corridor to maintain in the future.
DNH.VEGMGNT.VM.1220.5932

Integrated Vegetation Management (IVM)
A system of managing plant communities in which compatible and incompatible vegetation are identified; action thresholds are determined; tolerance levels are established; and control methods are evaluated, selected and applied to achieve management goals and maintenance objectives. IVM often integrates multiple methods to promote sustainable plant communities that are compatible with management goals

Interim Trimming: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for charges for mitigation of tree conditions that threaten reliability of one or more sections of primary conductor on a circuit or circuits not contained in the current fiscal year's annual plan of work.
DNH.VEGMGNT.VM.1235

Make Safe Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for assistance to private tree work as required to allow a landowner to perform property maintenance while following industry safety requirements.
DNH.VEGMGNT.VM.1010.5932

Permit Fees
This captures all charges for activities related to permitting, ie environmental permits, railroad permits, scenic roads, etc.
DNH.VEGMGNT.VM.1215.5932

Printed Material
This captures all charges for activities related to printed material to perform program needs: mailers, door hangers, tree removal forms, traffic control forms, etc.
DNH.VEGMGNT.VM.1215.5932

Program Assessment
A review and assessment of the vegetation maintenance program evaluating efficiency and effectiveness. Performed by a 3rd party contractor.
DNH.VEGMGNT.VM.1215.5932

VM Software
Vegetation Management software includes Ai-Dash and Terra Spectrum and others as needed. Ai-Dash and Terra Spectrum are 2 software tools utilized as work management system, evaluation tool, and reporting or projecting experiences or expectations.
DNH.VEGMGNT.VM.1215.5932

ROW IVM: Monarch Butterfly Conservation
This captures all charges for activities related to Monarch Butterfly Conservation to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

ROW IVM: Pollinator Education/Habitat
This captures all charges for activities related to incorporating promotion of pollinator habitat and cultural activities to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Clearing (Floor & Side & Removals):
This captures all charges for activities related to cutting, clearing, herbicide application and tree removal on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Herbicide
This captures all charges for activities related to herbicide application on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280.5934

Spot Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up of corrective action required, if any, to mitigate vegetation management concerns requested or reported by a customer between cycle work. Can usually be scheduled over next several weeks to months for efficiencies.
DNH.VEGMGNT.VM.1010.5931

Traffic Control: (Planned & Unplanned)
This captures all charges for traffic control expenses associated with annual planned cycle trim, tree removals, and unplanned work of spot trimming, trouble, interim work and other Vegetation Management work requiring traffic control.
DNH.VEGMGNT.VM.1218

Training
Scope of work, safety, software, process, or more training for program supervisors, administrators or crews as needed. Can be one on one or in group settings.
DNH.VEGMGNT.VM.1215.5932

Tree Planting:
This captures all charges for tree replacements in exchange for tree removals of full clearance, tree replacement to remediate property owner complaints, trees planted for Arbor Day events.
DNH.VEGMGNT.VM.1240

Trouble and Restoration Maintenance: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for response and corrective action to mitigate isolated tree related trouble, overhead line requests to mitigate tree related trouble and storm responses not covered by a storm specific charge number. It typically requires immediate response. That is, cannot be schedule weeks or months later.
DNH.VEGMGNT.VM.1210

VM
Vegetation Management

*Diameter of trees is measured 4.5' from the ground.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23
Request No. DOE 6-24

Date of Response: 9/15/23
Respondent: Anthony Strabone

REQUEST:

Reference DOE 3-2 a. Reliability Metrics.

a. In terms of project/budget priorities, how important is it to have 1st quartile reliability performance?
b. Please provide Liberty's SAIDI and SAIFI quartile performance rankings for each of the following conditions:
    i. When major storms are excluded.
    ii. When major storms are included.

RESPONSE:

a. The Company's priority is to provide safe, reliable service at a reasonable cost to all customers. When prioritizing projects/budgets, improvement in reliability performance is one of the factors considered when evaluating projects. The Company achieving 1st Quartile reliability performance is based on a comprehensive approach including Capital (project) investment, maintenance, and vegetation management.
b. Currently, in 2023, the Company's SAIDI and SAIFI quartile rankings are as follows:
    i. For both SAIDI and SAIFI, the Company ranks in the 1st quartile when major storms are excluded.
    ii. For both SAIDI and SAIFI, the Company ranks in the 2nd quartile when major storms are included.

Line	Phase	End Use	Anticipated kW Demand	Tuscan	9/28/2023 Status	Load Data Info Attachment #	Revenue Attachment	CIAC	Annual Distribution Revenue
1	1	[redacted]	1216	North	Complete	1-3.b.14	14	$0	$150,596
2	1	[redacted]	340	North	Complete	1-3.b.1	1	$0	$60,786
3	1	[redacted]	96	North	Complete	1-3.b.17	17	$0	$15,403
4	1	[redacted]	667	North	Complete	1-3.b.21	21	$111,814	$93,115
5	1	[redacted]	87	North	Complete	1-3.b.16	16	$0	$10,121
6	1	[redacted]	80	North	Complete	1-3.b.16	16	$0	see line 5
7	1	MB Retail 3	71	North	Complete	1-3.b.16	16	$0	see line 5
8	1	MB Retail 4	56	North	Complete, no tenant due to COVID	1-3.b.16	16	$0	see line 5
9	1	[redacted]	53	North	Complete	1-3.b.25	25	$0	$8,378
10	1	[redacted]	30	North	Complete	1-3.b.21	21	$0	$1,766
11	1	Restaurant 1	87	North	2024/2025 for buildings	N/A	n/a	N/A	N/A
12	1	Restaurant 2	127	North	2024/2025 for buildings	N/A	n/a	NA	N/A
13	N/A	[redacted]	378	North	Not started date unknown	N/A	n/a	N/A	N/A
14	N/A	[redacted]	36	North	Original 1547 was incorrect. Load sheets sent to Liberty provided for 424 kW, but billing records show 36 kW.	1-3.b.28	28	TBD	$216,505
15	1A	[redacted]	1661	South	Complete	1-3.b.18	18	$21,020	$254,040
16	1A	[redacted]	315	South	Complete	1-3.b.19	19	$0	$45,703
17	1A	Street Lights	10	South	Complete	1-3.b.26	26	$13,460	$2,971
18	1A	Street lights & well	16	South	Complete	1-3.b.27	27	$7,710	$5,182
19	1A	OMJ Buildings (Maintenance Buildings)	172	South	Hold until 2025	1-3.b.23	23	$0	$25,056
20	1A	[redacted]	74	South	Complete	1-3.b.24	24	$3,963	$11,513
21	1B	[redacted]	1233	South	*Complete*	1-3.b.22	22	*$35,866*	$182,003
22	1C	[redacted]	245	South	3 of 4 tenants moved in	1-3.b.2	2	$34,391	$42,946
23	1C	[redacted]	317	South	Complete	1-3.b.3	3	$0	$54,067
24	1C	Building 300 (5.2) Conatiner Store	109	South	Complete	1-3.b.4	4	$8,035	$16,658
25	1C	[redacted]	188	South	Complete	1-3.b.5	5	$27,124	$27,971
26	1C	[redacted]	135	South	Complete	1-3.b.6	6	$8,486	$20,733
27	1C	[redacted]	44	South	Complete, plus level 2 EV charger	1-3.b.7	7	$11,600	$7,203
28	1C	[redacted]	386	South	Complete	1-3.b.8	8	$9,302	$63,599
29	1C	[redacted]	80	South	Complete	1-3.b.9	9	$0	$13,044
30	1C	[redacted]	73	South	Complete	1-3-b.10	10	$0	$16,642
31	1C	[redacted]	28	South	Complete	1-3-b-11	11	$15,370	$4,978
32	1C	Drive Custom Fit (Gym)	107	South	Complete	1-3-b-12	12	$0	$21,202
33	2	Hotel/Conf/Retail Building 2000	1800	South	Hotel, Condos and 3 of the stores in. Opening 10/15 Expect all in service at end of 2023	1-3.b.13	13 Hotel	$0	$291,360
34	2	[redacted]	937	South	3/4 of Dolben is complete. Expect all in service at end of 2023	1-3.b.15	15	$0	$150,419
35	2A	Central Village Building 1400 & de-water (was within line 35)	2650	South	Redesign of Resi Village, Office Spaces, over 55+ & retail - 660,414 sf mixed use	Att 29	29	$36,640	$285,399
36	2B	[redacted]	2008	South	Awaiting transformers for resi. Garage in service. Commercial expected in service at end 2023	Att 30	30	$0	$99,832
37	2B	Central Village Building 1000-1500, 4000	4431	South	redesigned and densifying 2 buildings	Att 13	13 Central Village	TBD	$426,097
38	2C	Drug Manufacturer/Office Park/Garage/Multi Tenant	4000	South	Redesign of Resi Village, Office Spaces, over 55+ & retail - 660,414 sf mixed use	1-3.b.20	20	TBD	$877,873
		Total	24,343					$344,781	$3,503,161

Total North	**3,324**
Total South	**21,019**
Total Tuscan Village	**24,343**
Total Tuscan Village Completed	**7,416**
Total Tuscan Village In Progress/No Tenant	**5,082**
Total Tuscan Village not developed	**11,845**
	24,343