Least Cost Integrated Resource Plan

Liberty Utilities (Granite State Electric) Corp.
d/b/a Liberty

Docket No. DE 21-XXX

January 14, 2021

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1. EXECUTIVE SUMMARY

Pursuant to the laws governing least cost integrated resource plans ("LCIRP"), RSA 378:37 through 378:40, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty ("Liberty" or the "Company") submits this LCIRP for the period 2022 through 2026. The Company's most recent LCIRP was approved by the New Hampshire Public Utilities Commission ("Commission") in Order No. 26,039 (July 10, 2017). The current LCIRP was prepared in compliance with the Commission's directives in Order Nos. 26,039 and 26,408 (Sept. 23, 2020).[1]

The purpose of the LCIRP is to provide the Commission with an understanding of the resource planning process employed by the Company to meet its obligation to provide safe, reliable, and least-cost electric service to its customers. The LCIRP describes the Company's approach to develop a forecast of electricity demand under several planning scenarios, and the Company's ability to meet its supply, transmission, and distribution obligations under various planning conditions.

The LCIRP follows the general approach, format, and objectives of the Company's most recent LCIRP filing in 2016 and modified LCIRP filing in 2019, which is to comply with RSA 378:37, the New Hampshire Energy Policy:

> [I]t shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest

1 "In this Order, the Commission finds that Liberty's July 15, 2019, filing meets the requirements of Order No. 26,039 and Order No. 26,261, which granted partial waiver of Liberty's statutory requirement to file a 2019 Least Cost Integrated Resource Plan and instead required a more limited document. Consistent with the filing requirements under RSA 378:38, Liberty shall submit its 2021 LCIRP filing on or before January 14, 2021." Order No. 26,408 at 1.

> reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities.

RSA 378:38 requires electric and natural gas utilities to file an LCIRP, and specifies that the LCIRP shall include the following:

- A forecast of future demand for the utility’s service area;
- An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs;
- An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources;
- An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of “smart grid”' technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies;
- An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility’s assets or customers;
- An assessment of the plan’s long- and short-term environmental, economic, and energy price and supply impact on the state; and
- An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

This LCIRP filing, as summarized in Appendix A, meets the requirements of RSA 378:38.

This LCIRP also addresses Commission's directives in Order No. 26,408, which required the Company to:

- Work with Staff to provide access to the distribution electric operating procedures through the Liberty Utilities – Manuals site.

- Develop a list of planned capital projects that may be candidates for avoidance and/or deferral through deployment of Non-Wires Solutions ("NWS").

- Meet with the Settling Parties to identify an NWS candidate that should be the focus of a more detailed analysis provided within the LCIRP filing. This analysis of NWS should consider utility system benefits including, but not limited to, avoided distribution capacity costs, avoided energy costs, and avoided transmission costs. The analysis shall include an evaluation of the demand reduction potential associated with energy efficiency and load curtailment, as well as other NWSs.

- Include a document similar to Sections 4.4 ("Distribution Planning Process") and 5 ("Non-Wires Alternatives T&D Integration Process"), and Appendix E ("Hypothetical Case Study: Evaluation of Non-Wires Solution") of the 2016 LCIRP which provide descriptions of the planning process employed to assess NWS as part of the Company's broader planning processes, and, the steps taken to incorporate NWS into its planning decisions to reduce or defer traditional infrastructure investments.

- Work with the settling parties to determine how the following issues will be addressed within the 2021 LCIRP: 1) how the risk profile evaluation for NWS is conducted, including contributing factors and issues; 2) options to mitigate identified risks; 3) how risk is incorporated into the planning process, including how risks and costs are weighted to identify when a reduction in cost justifies additional risk; 4) the potential for hybrid projects; 5) ways in which the Company might attain a more detailed analysis of the benefits and costs; and 6) how potential NWS are identified for detailed analysis.

The Company met with the Settling Parties on December 18, 2020, to discuss the non-wires solution presented in this plan. The Bellows Falls Study, which describes the reliability and resilience issues in this area, is included in this Plan in Appendix F. Liberty has agreed to evaluate non-wires solutions in the Bellows Falls area and provide a detailed NWA evaluation within 6 months of this filing as an amendment to this Plan. The Settling Parties appreciated the discussion and noted they looked forward to seeing the information in the filing.

The LCIRP describes the Company's four planning phases. The first phase is to develop a long-term forecast of demand requirements. The second phase is to develop a detailed energy supply plan to meet those requirements. The third phase is to prepare a distribution plan that includes evaluation of wires and non-wires alternatives to address system deficiencies. The fourth and final phase is to evaluate and integrate the energy efficiency and demand side management programs into the LCIRP.

In the first phase, the Company developed an econometric model to forecast peak demands through 2037. The forecast model incorporates the impact of weather as well as demographic and local economic conditions on peak demands. Refer to Section 2 for additional details.

In compliance with New Hampshire's electric market restructuring and generation divestiture, the Company procures power for its energy service customers through a competitive solicitation process in semi-annual, short-term commitments consistent with the Commission's orders and regulations. The Company continues to monitor market rules and other wholesale electricity issues that impact electric prices.

The Company performed a detailed evaluation of its distribution system based on the forecast results discussed above and the condition of its distribution facilities. The evaluation utilized the forecast of peak demands for each feeder and substation based on extreme weather conditions, as well as data depicting the operating performance and condition of the distribution facilities. This evaluation is used to determine whether the operating capacity of the distribution facilities is adequate under normal and contingency conditions.

Liberty established planning criteria, which were filed in Docket No. DE 19-064 and approved by Order No. 26,376 (June 30, 2020), for normal and contingency operating conditions that are applied in concert with the thermal ratings of the distribution facilities to identify violations or deficiencies in the capacity of the distribution facilities. The deficiencies are then prioritized by risk of occurrence and impact on customers. The Company develops solutions to the deficiencies in the form of individual project proposals, which are then included in the Company's five-year capital budget based on their priority level and cost considerations. Non-wires alternatives are evaluated and considered as potential solutions to distribution system deficiencies, subject to certain screening criteria and risk analyses.

Liberty has evaluated its distribution system in light of substantial changes in customer expectations and regulatory directives in recent years and is proposing to incorporate selected "Smart Grid" technologies that will modernize the Liberty distribution system. The Grid Modernization element of this plan provides substantial positive value to customers, including increasing resilience (i.e. faster recovery from system damage), lower overall customer costs, and improved safety and reliability of its system. The new Advanced Distribution Management Systems ("ADMS") and Automated Metering Infrastructure

("AMI") will serve as the backbone of this grid modernization program that Liberty plans to implement over the next five years, investing in an enhanced customer service experience of the future. As demonstrated in Section 5 of this LCIRP, the costs of these new digital technology management systems will provide positive economic value for customers that substantially exceed the costs of these programs over the next 10 years.

The Company performed a detailed assessment of its NHSaves energy efficiency measures and programs to ensure they meet the requirements of the LCIRP. The assessment shows that the Company's energy efficiency programs have resulted in savings of more than 910,000 lifetime megawatt hours at a benefit value of almost $89 million, reductions in peak load, and significant environmental and health benefits.

Key results and findings of the LCIRP include:

- Under the extreme weather scenario, Liberty's summer peak demand is projected to grow an average of 0.87% per year over the 2021 to 2037 planning period. Winter peak demand is projected to grow 0.74% per year on average over the same time period. These growth rates incorporate forecasted PV and electric vehicle charging projections for New Hampshire.

  The Company's five-year capital budget is $124 million, with spending on mandated and growth programs representing 41% of the budget, and spending on discretionary items representing 59% of the budget;

- The five-year capital budget includes $21 million for the recommended Distribution Grid Modernization Program, which will bring many benefits to customers, including, (1) enhanced outage management system allowing for faster recovery from system damage, (2) lower costs through use of "conservation voltage management," (3) better forecasting for each feeder on the system, (4) improved asset management, and (5) more efficient integration of distributed energy resources. Liberty is proposing to implement this Program with specific pilot projects as described in detailed in the Liberty Grid Modernization Study in Section 5 and Appendix E in this Plan.

- The Company's distribution planning process integrates non-wires alternatives, although the Company's pursuit of non-wires alternative solutions requires a more detailed analysis of the benefits and costs, including technical studies that would require additional resources;

- The LCIRP is filed in conjunction with the filing of the three-year Energy Efficiency Resource Standard Settlement Agreement in Docket No. DE 20-092. As of the date of this filing, the Settlement Agreement has not been approved.

- The key impacts of the Company's LCIRP on environmental, economic, and energy price and supply impacts on the State of New Hampshire include the following:

    - The Company's competitively sourced energy supply procurement process, consistent with the Settlement Agreement approved by the Commission in Docket No. DE 05-126 in Order No. 24,577 (Jan. 13, 2006),[2] ensures energy supply is delivered to customers at the lowest reasonable cost, while considering certain financial and qualitative criteria.

    - The Company's Renewable Energy Certificates ("REC") procurement, energy efficiency programs, and net metering tariffs to provide economic and environmental benefits to the state by supporting jobs in the renewable energy industry and reducing reliance on sources of electric generation produced outside the state that emit greater amounts of pollutants.[3]

    - The integration of grid modernization technologies and use of non-wires solutions into the Company's distribution planning process will provide economic and other benefits to the state through lower costs to the customer, improved reliability, planning, increase in customer DERs, de-carbonization, and the reduction of peak loads.

2 As amended by Order Nos. 24,922 (Dec. 19, 2008) in Docket No. DE 08-011, amended by Order No. 25,601 (Nov. 27, 2013) in Docket No. DE 13-018, and further amended by Order No. 25,806 (Sept. 2, 2015) in Docket No. DE 15-010 (as amended through these subsequent orders, the "Settlement Agreement").

3 Specifically, carbon dioxide (CO_2), sulfur oxides (SOx), nitrogen oxides (NOx), particulates, and other pollutants.

These results and findings demonstrate compliance with RSA 378:38 as detailed in the following sections.

The remainder of this LCIRP filing is organized as follows:

Section 2 discusses the Company's demand forecast methodology, including the econometric model used to develop the demand forecast.

Section 3 describes energy supply options, which are met by the wholesale markets and administered by the Independent System Operator New England ("ISO-NE"). This section describes how energy markets within ISO-NE are structured such that the Company can procure an adequate supply and provide demand resources to meet reliability objectives at the lowest reasonable cost. The LCIRP also details the transmission planning process and the Company's ongoing collaboration with National Grid, Liberty's transmission provider.

Section 4 describes the process to enhance the reliable operations of the electric distribution system that provides electric service to Liberty's customers, including the role of non-wires alternatives in Liberty's distribution planning and procurement process.

Section 5 describes the proposed Distribution Grid Modernization Program that will integrate selected digital technologies, providing economic and other benefits to customers and the other citizens in the State of New Hampshire.

Section 6 describes the role of energy efficiency and demand side management programs in resource planning and procurement process.

2. DEMAND FORECAST

2.1 Purpose

The planning process begins with a forecast of customer demand, or load. The demand forecast at the system level is based on an econometric model that is developed on both a weather-normalized and weather-probabilistic basis. The demand forecast provides a foundation for the evaluation of energy supply and distribution facilities that follow. The demand forecast is utilized in three types of planning studies:

- Area studies – determine expected circuit overloads and evaluate alternatives for system reinforcements. These studies are generally prepared for a three- to 15-year time frame and address specific load areas, including the area supply system, substations, and distribution feeders;
- Interconnection studies – are designed to determine the required interconnection facilities and system reinforcements required for specific generation and distribution projects; and
- Annual plan – includes the process steps described in Appendix C, including Non-Wires Solutions, and results in specific project proposals that have been prioritized and submitted for inclusion in the capital plan.

2.2 Methodology

The Company utilizes a multi-step, top-down / bottom-up process. First, the Company uses an econometric model to forecast Liberty's system summer and winter peak loads (i.e., "bottom-up") for each area. The explanatory variables include historical and forecasted economic conditions at the county level, historical peak demand data for each Area, and a forecast of weather conditions based on historical data from a Concord, New Hampshire, weather station. The model also applies certain demographic variables such as number of households. The system seasonal peak forecasts are then split into Eastern and Western jurisdictions using Liberty's township sales information, as well as July and December 2019 peak coincident Eastern and Western area percent contributions. Appendix B includes the Company's detailed demand forecast report.

The econometric model is used to simulate the historical and forecasted peak demand for each PSA under normal and extreme weather conditions. The normal weather simulation assumes average weather conditions for each year of the forecast. Normal weather conditions are determined by averaging the weather for the highest peak day of a 20-year historical period. As an average of historical weather, the normal weather forecast becomes a "50/50" case, with a 50% probability that actual weather is greater than or less than the forecasted conditions. The extreme weather scenario takes the weather conditions associated with the highest peak day over a 20-year history and applies these extreme conditions to all future years of the forecast. Based on the historical experience, there is only a ten percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario. That is, the extreme weather forecast is a "1 in 10" case.

The peak demand forecast for each area incorporates historic energy efficiency savings achieved, since such savings are reflected in the historical usage data employed by the model. The energy efficiency measures are those specifically installed through the NHSaves efficiency programs relating to both residential and non-residential customers. Similarly, the impact of distributed generation installed to date is also included in the historical peak demand. In developing the peak demand forecasts, the forecast assumes that load reductions achieved historically through the Company's energy efficiency programs continue through the time period of the forecast.

Liberty has developed a demand forecast that incorporates growth in electric vehicle charging and in distributed generation activity. For electric vehicle charging, the ISO-NE Final 2020 Transportation Electrification Forecast[4] was applied based on Liberty's proportion of the 2020 winter and summer non-coincident peaks. The distributed generation growth uses both historic Liberty distributed generation capacity and the ISO-NE Final 2020 PV Forecast[5] for New Hampshire. Liberty's behind the meter PV forecast growth is based on the ISO-NE's forecast of PV growth for New Hampshire. Liberty took the proportion of existing PV installed for the Company against the installed capacity in the entire state and applied that proportion to the ISO-NE forecast to determine the gross PV forecast for Liberty. To avoid double counting PV growth, the company developed an auxiliary regression model that includes installed capacity and time. The company took the resulting PV projections from the auxiliary regression model and subtracted the gross PV forecast to come out with the net and final behind the meter PV forecast to be applied to the summer peak.

Once the forecast is developed, Liberty makes certain "out of model adjustments" to account for known future loads or generation (i.e., "top-down"). Specifically, adjustments are made for new load greater than 300 kW interconnecting to Liberty's distribution system in the near future, or distributed generation greater than 1,000 kW that is expected to interconnect. To

4 https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_transp_elec_forecast.pdf
5 https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_pv_forecast.pdf

the extent that any distributed generation below 1,000 kW occurred in the historical period, it is captured in the historical peak data used to develop regression models and therefore is considered "embedded" in the data.

The growth rates are applied to each of the substations and feeders within the area. Liberty's distribution planners then adjust the forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planners use the forecasted peak loads for each feeder/substation under the extreme weather scenario to perform planning studies and to determine if the thermal and contingency capacity of its facilities is adequate.

System seasonal peak forecasts are divided into the Company's Eastern and Western jurisdictions, using town-level sales information as well as July and December 2021 peak coincident Eastern and Western PSA percent contributions. Separate annual forecasts are estimated for 19 towns in the Company's New Hampshire service territory.[6] The regression equations relate annual town-level kilowatt-hour ("kWh") deliveries to a time trend variable and Cooling Degree Days ("CDD") to predict town kWh load for each forecast year. In order to flatten the change in township usage over the historic period, the time trend variable is expressed as a log function. The system peak day values are allocated to the individual townships by utilizing the annual township sales regression models.

6 The town of Langdon is included in the Acworth forecast and the town of Orange is included in the Canaan forecast, thus generating 19 forecasts for 21 towns.

2.3 Results

The forecast model projects an increase in Liberty's summer peak demand from a weather adjusted 188.5 megawatts ("MW") in 2021 to 202.6 MW in 2037.[7] This results in an average annual increase of 0.4% prior to any "out of model adjustments" for new load greater than 300 kW.

The Company developed an "extreme weather" forecast of summer peak demands based on a 1-in-10 weather scenario. The extreme weather forecast model projects an increase from 188.5 MW in 2020 to 217.34 MW in 2037. This results in an average annual increase of 0.87%.

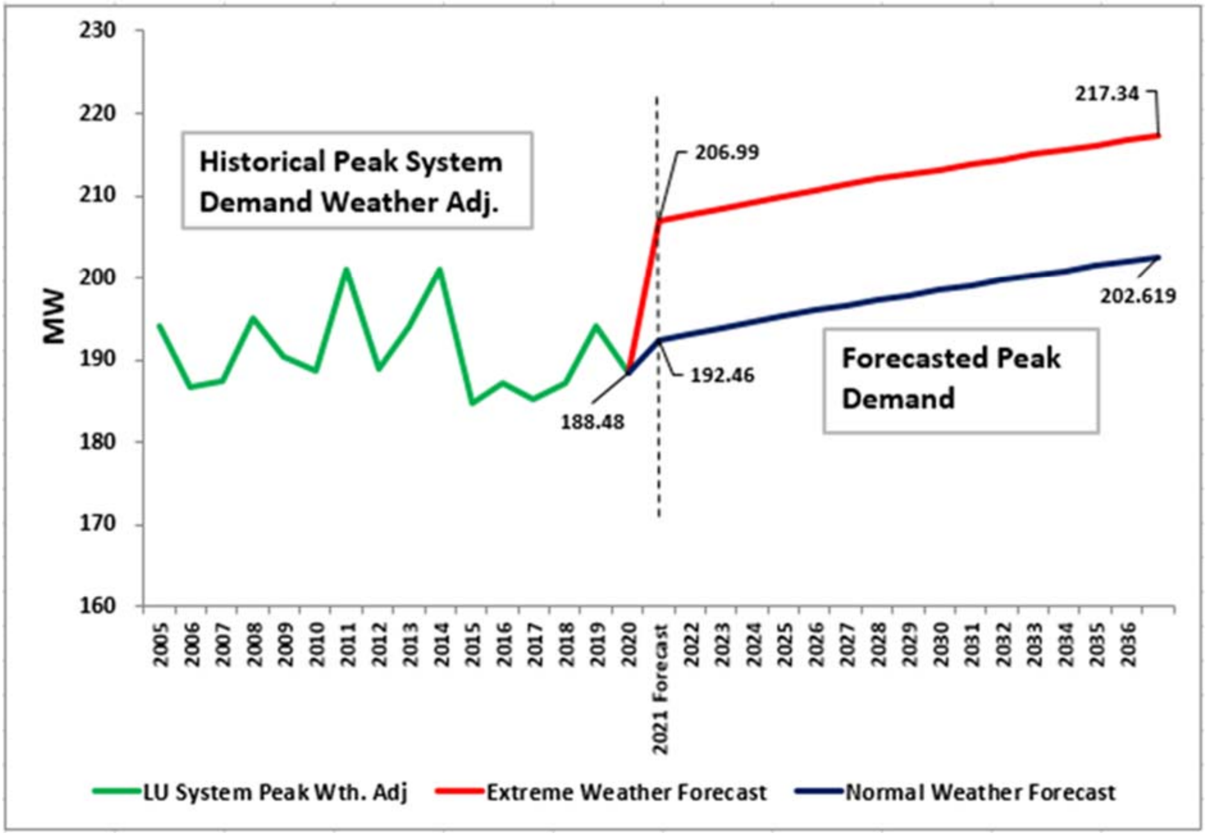
The Company also developed a forecast of peak demands for Liberty's Eastern and Western distribution areas.[8] Under the extreme weather scenario, the forecast model projects an increase in summer peak demand in Eastern area from 105.4 MW in 2021 to 110.6 MW in 2037. In the Western area, the model projects an increase in summer peak demand from 101.6 MW in 2021 to 106.7 MW in 2037.

The forecast model was then adjusted for spot loads to reflect new customer demands larger than 300 kilowatts ("kW") that will be added to the system in 2021 or beyond.

7 Liberty's distribution system in New Hampshire is, in general, summer peaking and summer limited.
8 The Eastern PSA includes the towns of Derry, Pelham, Salem, and Windham. The Western PSA includes the towns of Acworth, Alstead, Bath, Canaan, Charlestown, Cornish, Enfield, Grafton, Hanover, Langdon, Lebanon, Lyme, Marlow, Monroe, Orange, Plainfield, Surry, and Walpole.

Figure 2.1 shows the historical and projected growth in peak demand under normal and extreme weather scenarios.

Figure 2.1. Summary of Peak Demand Forecast



3. ENERGY SUPPLY & TRANSMISSION PLANNING

3.1 Electricity Market Overview

The ISO-NE is the independent, not-for-profit company authorized by the Federal Energy Regulatory Commission ("FERC") to perform three critical, complex, and interconnected roles for the New England region: (1) wholesale electric grid operation, (2) market administration, and (3) power system planning.[9]

The ISO-NE, with input from the New England Power Pool ("NEPOOL") stakeholder process, is responsible for administering the wholesale electricity markets and for ensuring reliability throughout the New England region.

The wholesale electric market consists of energy, capacity, and various ancillary services. For five of the six New England states (excluding Vermont), electric generation ownership is severed from transmission and distribution ownership. That is, electric utilities do not own generation; rather electric generators bid their power into the ISO-NE wholesale market. Load serving entities, such as Liberty, then procure supply from across the region to best meet the demands of their retail customers receiving energy service. As a result, Liberty is actively monitoring the wholesale energy markets to ensure it provides its customers with a reliable and least-cost supply of electric power.

Summary of the ISO-NE Wholesale Market

To maintain the reliable and efficient operation of the New England power system, the ISO-NE undertakes a comprehensive regional system planning process each year. Notwithstanding the region's system improvements, the ISO-NE notes that the region is facing three key issues:

- Energy security—Although many projects for resource development have been proposed in the region, energy-security and reliability issues may arise from energy-

9 http://www.iso-ne.com/about/what-we-do/three-roles

production limitations associated with "just-in-time" fuel sources (i.e., natural gas); variable energy resources (VERs), like intermittent wind and photovoltaics (PV); and compliance with environmental regulations. In response, New England state policies and incentives for developing renewable resources, as well as energy efficiency (EE) and imports from neighboring regions, are helping offset regional natural gas demand. Additionally, the ISO, with stakeholder input, is working on near-term and long-term market improvements to expand the existing suite of energy and ancillary services that will cost effectively address uncertainties and supply limitations and enhance energy security.

- Transmission development—Transmission improvements are needed to maintain and enhance the reliability of the regional power system and support state policies to access remotely located sources of clean energy. Transmission plans are in place throughout the region to meet system needs.

- Grid transformation—The widespread addition of inverter-based technologies (which use power electronics to convert between alternating current [AC] frequencies or between AC and direct current [DC] frequencies) and distributed energy resources (most which the ISO cannot observe or control like traditional resources) would require transmission upgrades and control system improvements for reliably interconnecting these resources to the grid. Structural changes to the transmission and distribution systems are being analyzed and implemented, and new procedures put in place, to help transform the grid and improve the reliable, economical, and environmental performance of the system overall.

The ISO-NE and its stakeholders are modifying the market design, system operations, and planning activities to address these regional strategic planning issues, prepare for changes likely to confront the New England power system, and assess potential system enhancements and modifications. These planning activities, which are designed to ensure a reliable and economical power system, take place through an open stakeholder process that includes input from the Planning Advisory Committee ("PAC"). The ISO-NE also receives advisory input through the NEPOOL committee structure on potential changes to the market design, provisions of the Open Access Transmission Tariff ("OATT"), and supporting procedures.[10]

Auctions in the Forward Capacity Market ("FCM") ensure the system has sufficient resources to meet the future demand by paying resources to exist and be available to meet the projected demand for electricity three years out. For the first seven auctions, excess capacity in the region helped keep capacity prices relatively low. The eighth Forward Capacity Auction ("FCA #8") concluded in a small deficit in necessary power system resources, resulting in higher prices to meet consumer demand in New England in 2017–2018. FCA #9 concluded with sufficient resources for 2018–2019 but at clearing prices that were higher than in previous auctions, reflecting the need for new resources to ensure a reliable supply of power in New England. Since then changes in the auction rules and competition have lowered the clearing prices substantially. The most recent auction, FCA 14, cleared at an all-time low price of $2/kW-month. The surplus capacity in FCA 14 was almost 1,500 MW, or 5%, above the installed capacity requirement, despite a significant amount of capacity (over 2,500 MW) exiting the capacity market, mostly for a one-year period, in response to low prices.

According to the ISO-NE, New England is currently energy constrained with its existing fuel infrastructure dependent on natural gas. This is especially challenging in the winter. While ISO-NE projects sufficient resources through 2028 it will be challenged to integrate the significant quantity of intermittent resources planned for New England. As of April 2019

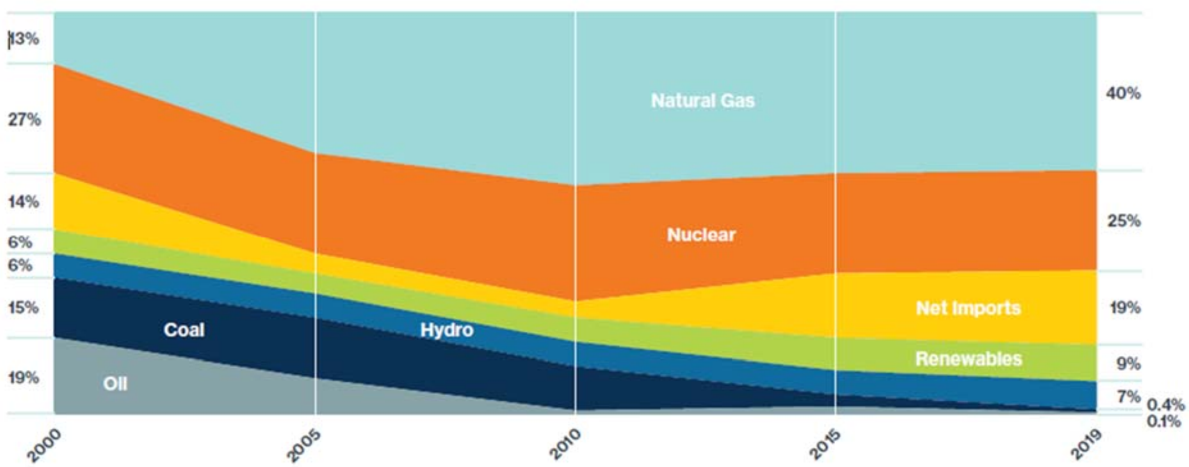
10 *Ibid*.

there are planned 11,316 MW of wind resources, 3,070 MW of large-scale PV, and 1,381 MW of battery storage to be interconnected to the New England power system.

Energy Market Prices

In 2019, natural gas accounted for 40% of total electric energy production in the New England region, while coal, oil, nuclear, and hydro/renewables[11] accounted for 0.4%, 0.1%, 25%, and 16%, respectively and net imports of 18.5%. This compares to a resource mix of 15% natural gas, 18% coal, 22% oil, 31% nuclear, and 15% hydro/renewables in 2000 (See Figure 3.1 below).[12]

Figure 3.1 Percent of Total Electric Energy Production by Fuel Type[13]

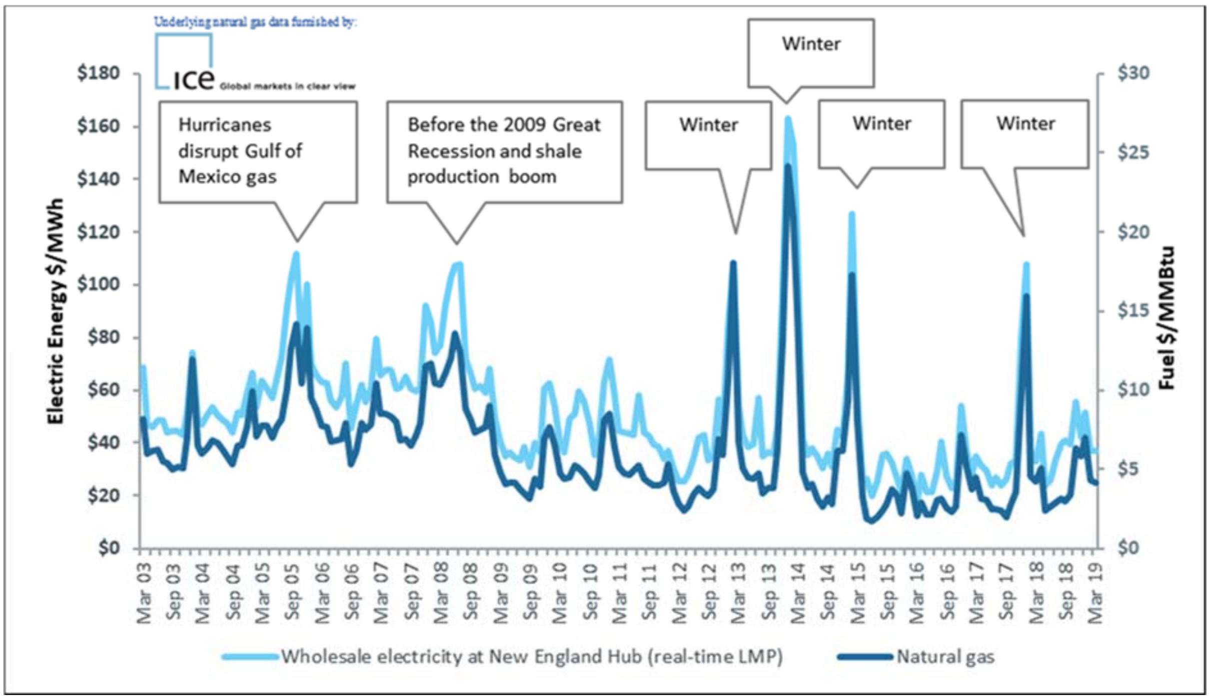


Because a majority of New England's electricity generation is fueled by natural gas, energy market prices in New England closely track movement in natural gas market costs (see

11 https://www.iso-ne.com/about/key-stats/resource-mix.
12 http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix
13 http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix

Figure 3.2 below). The marginal unit setting the energy market clearing price is most often a natural gas fired generator, and such generating units were the marginal units setting the real-time energy market clearing price during approximately 75% of the hours during 2019.[14]

Figure 3.2. Link between Natural Gas and New England Wholesale Electricity Prices[15]



From 2003 through 2019, the price of natural gas declined significantly in New England with increasing production from the Marcellus Shale and moderate winter weather that resulted in minimal natural gas pipeline constraints. As such, wholesale electricity prices declined simultaneously.[16]

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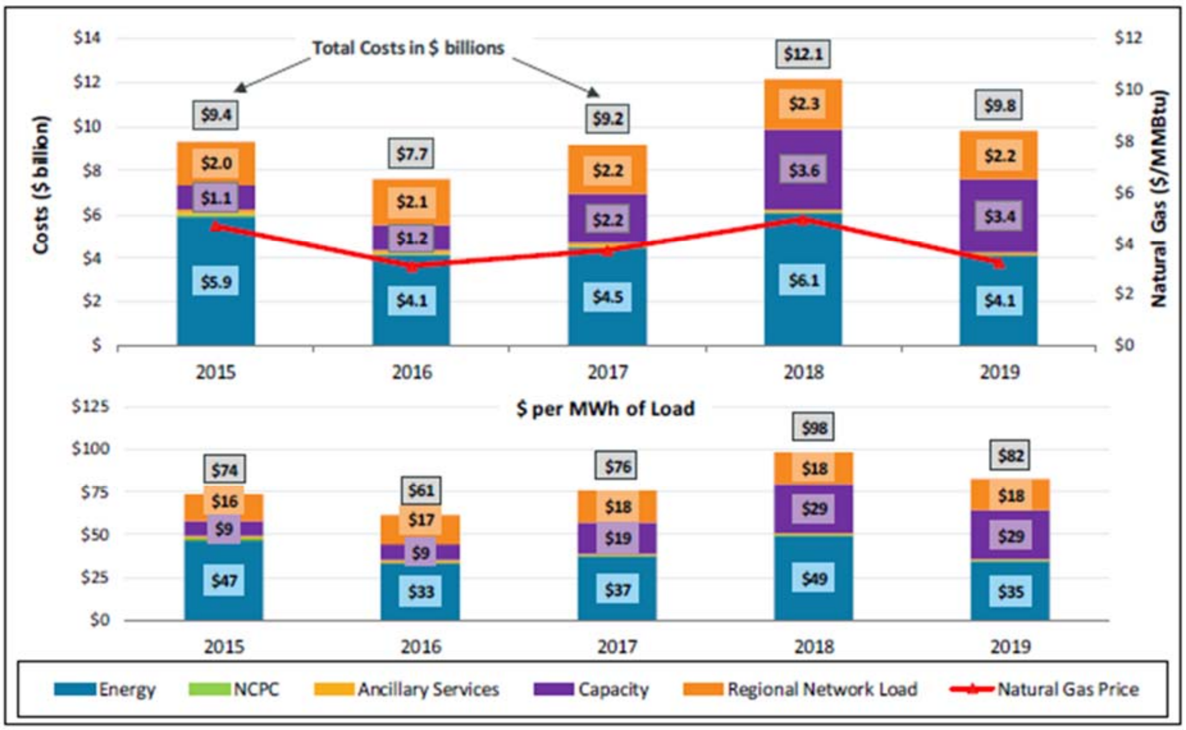
14 ISO New England's Internal Market Monitor, 2019 Annual Markets Report, May 26, 2020, at 100.
15 Source: http://www.iso-ne.com/about/what-we-do/key-stats/markets
16 http://isonewswire.com/updates/2015/10/30/summer-2015-the-lowest-natural-gas-and-power-prices-since-20.html. In fact, summer 2015 saw the lowest average wholesale power prices since the competitive wholesale electric markets were implemented in 2003.

Figure 3.3 below provides a comparison of the wholesale costs of electricity to natural gas pricing. The trend in wholesale costs to meet the Company's default service requirements over this same period is similar to that depicted below:

Figure 3.3. ISO-NE Wholesale Market Cost Summary[17]



3.2 Supply Planning

New Hampshire partially restructured its retail electricity market in 1998, severing generation from distribution (with the exception of Public Service Company of New Hampshire ("PSNH")), and PSNH, now Eversource, completed divestiture of its generating assets in 2018. As such, New Hampshire's electric distribution companies, including

17 ISO New England's Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, at 3.

Liberty, do not own generation. Instead, Liberty procures electricity supply for its customers on energy service every six months through a solicitation process that is reviewed and approved by the Commission.

The solicitation, bid evaluation, and procurement process that is used to procure energy service for Liberty's customers complies with a Settlement Agreement approved by the Commission in Order No. 24,577 (Jan. 13, 2006). The Settlement Agreement has been amended multiple times to respond to changes in the wholesale market. The most recent amendment was the result of the Commission's approval to shift the two six-month solicitation periods from November 1/May 1 to February 1/August 1 to reduce the retail price volatility of the winter period by splitting the two highest cost winter months (January and February) into two separate periods. The Commission approved this change in Order No. 25,806 (Sept. 2, 2015). The Commission later found that Liberty's most recent solicitation for Energy Service complied with the procedures approved in the Settlement Agreement, that the selection of the winning suppliers was reasonable and appropriate, and that the resulting retail rates were market-based and thus approved the filing. Order No. 26,431 (Dec. 14, 2020). Liberty expects to issue its next solicitation in May 2021 for a six-month energy service supply starting on August 1, 2021.

3.3 Renewables Planning

Liberty, like all retail suppliers of electricity in New Hampshire, is required to meet annual Renewable Portfolio Standards ("RPS") based on its sales of energy service. Liberty's process to comply with the RPS is specified in a Settlement Agreement approved by the

Commission in Order No. 24,953 (Mar. 23, 2009). Liberty issues a solicitation for RPS Renewable Energy Certificates ("REC") twice a year around the same time as its energy service solicitations are issued. Liberty contracts for RECs on a short term basis to reflect both the actual or expected energy service sales. This is done to minimize any oversupply of RECs due to migration of energy service customers to a retail choice supplier and to take advantage of market prices.

3.4 Transmission Planning

The New England transmission system, while owned by various transmission utilities (including National Grid), is subject to ISO-NE's operational, reliability, and planning authority pursuant to the ISO New England Transmission, Markets and Services Tariff ("ISO Tariff"). Because Liberty does not own any transmission facilities, it is a transmission customer of National Grid. As the transmission owner, National Grid provides service through the ISO Tariff. National Grid manages its New England transmission system – its New England facilities that are operated at voltages of 69 kV and up – as a single integrated system, and as part of the larger New England transmission system, in order to achieve efficiencies and to align processes across its business. It is Liberty's responsibility, as the transmission customer, to provide National Grid with the electrical system information necessary to enable National Grid to fulfill its transmission owner service requirements. The information Liberty provides to National Grid typically includes electric distribution system peak and off peak loads, power factor, and the actual or estimated impact of distributed generation and demand-management efforts. These parameters are available to both companies and are periodically reviewed and collaboratively utilized.

3.5 Impact Assessment

The Commission-approved processes used to secure both a reliable and competitively sourced supply for its energy service customers and to meet its RPS obligations have been found to be consistent with RSA 374-F and RSA 362-F. As a result, Liberty meets its obligations at the lowest reasonable cost to its customers.

4. DISTRIBUTION PLANNING

Introduction

The purpose of this section is to describe Liberty's distribution planning process, including the evaluation of wire and non-wire solutions to address system deficiencies. This section will also discuss compliance with the Commission's requirements in Docket No. DE 16-097, the proceeding in which the Company's most recent LCIRP was reviewed and approved, along with the approved Settlement Agreement in Docket No. DE 19-120, 2019 Least Cost Integrated Resource Plan. See Order No.26,039 and Order No. 26,408, respectively.

The goal of distribution planning is to provide adequate capacity for safe, reliable, resilient, and economic service to customers with minimal impact on the environment. To achieve that goal, the distribution system is planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal" or "N-0") and first contingency conditions ("N-1") incorporating existing planning criteria. Planning engineers apply tools and criteria to evaluate the capacity and performance of the system, while harnessing the capability of existing facilities that are under-utilized before constructing new facilities. When new facilities are required to address system needs, the

Company has initiated a process to evaluate non-wire solutions in addition to more traditional wire alternatives, as circumstances permit.

Liberty updated the Distribution Planning Criteria as part of the settlement agreement resolving Liberty's most recent rate case, Docket No. DE 19-064. Liberty's distribution planning criteria is included as Appendix D to this LCIRP.

4.1 Background

For purposes of distribution planning it is important to define the terms "supply system," "supply line," "distribution system," and "distribution line."

- A supply system is a collection of electrical facilities, including transformers and lines, which transports power between substations. The objective of a supply system is to move power from one substation to another for use at its final destination. From a distribution perspective, Liberty's supply system in New Hampshire operates at voltages between 23 kV and 13.8 kV.
- Supply lines may be overhead or underground and operate within the voltage levels described above. At least two supply lines usually serve any one substation, providing redundant electric service if one line fails.
- A distribution system is a collection of overhead and underground lines that route the power from the substation to customers for direct use. Transformers change voltage at substations from transmission or supply lines to primary distribution levels, which range from 13.2 kV to 2.4 kV. Distribution voltages are regulated for utilization within specified ranges in accordance with Puc 304.02. Additional transformation occurs along each distribution line to convert voltage to a useable value for customers, such as 120 or 240 volts.
- A distribution line is a single radial feeder that can serve up to 12 MVA of load. The main line of each feeder branches into several main routes that end at open interconnection points. Here, the feeder may be interconnected to an adjacent circuit to facilitate manual reconfiguration in order to isolate faulted sections of the line and

to "switch before fixing" to quickly restore customers. Each feeder is usually divided into several switchable elements. During emergencies, segments can be reconfigured to isolate damaged sections and re-route power to customers who would otherwise have to remain out of service until repairs were made. All individual distribution lines in an area constitute a distribution system.

Liberty's distribution system is comprised of supply (or sub-transmission) and distribution lines shown on Figure 4.1.

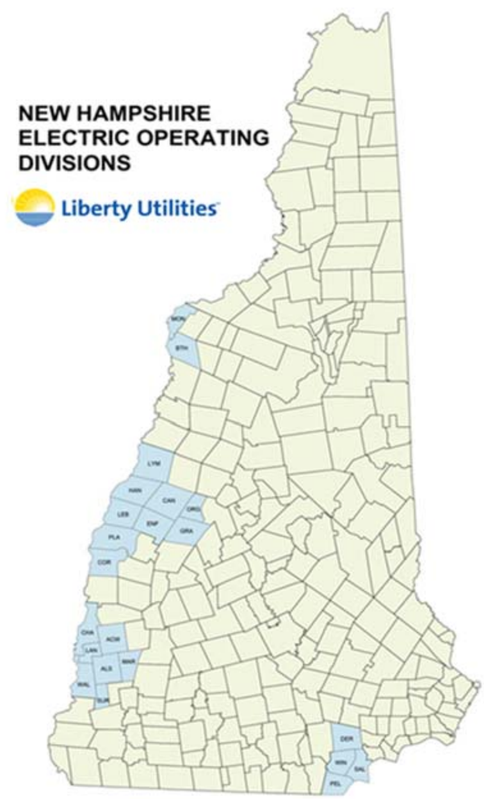
Figure 4.1. Supply and Distribution Lines

Voltage	Line Miles
13.2 kV Distribution	1,154
2.4 kV Distribution	13
13.8 kV Sub-Transmission (Supply)	18.5
23 kV Sub-Transmission (Supply)	13

4.2 Overview of Distribution System

Liberty provides electric service to the communities of Acworth, Alstead, Bath, Canaan, Charlestown, Cornish, Derry, Enfield, Grafton, Hanover, Langdon, Lebanon, Lyme, Marlow, Monroe, Orange, Pelham, Plainfield, Salem, Surry, Walpole, and Windham (see Figure 4.2).

Figure 4.2 Service Area



Distribution Substations

The distribution substations within Liberty's territory are a mixture of stations with one or more transformers. In the Eastern area, Baron Ave, Salem Depot, Olde Trolley and Spicket River substations involve 23/13.8 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders and are wholly owned by Liberty. In the Western area, Hanover, Craft Hill, Lebanon, and Enfield substations involve 13.8 kV Supply and 13.2 kV regulation. Distribution substations supplied by the 115 kV circuits are jointly owned between Liberty and National Grid. Currently, Liberty and National Grid maintain five distribution substations[18] containing nine power transformers in the Liberty service territory.

Sub-Transmission System

Liberty's sub-transmission system is designed to provide adequate capacity between load centers at reasonable cost and with minimal impact on the environment. It provides supply to distribution substations and consists of those parts of the system that are neither bulk transmission nor distribution. The voltages for the sub-transmission system include 23 kV and 13.8 kV. The sub-transmission system is designed in an open loop system and generally provides a redundant supply for distribution substations. Currently, Liberty maintains ten sub-transmission lines.[19]

Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits. The feeder may be interconnected to an adjacent circuit to facilitate manual reconfiguration in order to isolate faulted sections on the line and to "switch before fixing" to quickly restore customers. Each feeder is usually divided into several switchable elements or sectors.

18 Golden Rock, Pelham, Slayton Hill, Mt. Support, and Michael Avenue.
19 Of the ten sub-transmission lines, five are jointly maintained by National Grid and Liberty.

During emergencies, segments can be reconfigured to isolate damaged sections and re-route power to customers who would otherwise have to remain without service until repairs were made. Liberty will increase the use of distribution automation to expedite these reconfigurations and increase the ability to remotely operate the system. Currently, the Liberty distribution system is comprised of approximately 40 feeders ranging from 2.4 kV to 13.2 kV.

4.3 <u>Distribution Planning Process</u>

Liberty's distribution system in New Hampshire is, in general, summer peaking and summer limited. Liberty conducts an annual capacity planning process with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the system to respond to contingencies that might occur. The distribution planning process is illustrated in Appendix C and incorporates the Improvement Project Evaluation Process and NWS Analysis Workbook presented in the strategy document DAS-016 Guidelines for Analysis of Non-Wires Solutions found in Appendix D. The distribution planning process includes the following tasks:

- Forecast peak demand using an econometric model, which includes: (a) weather adjustment to reflect recent actual peak loads; (b) projected customer and demand growth; (c) incorporation of historical energy efficiency savings; (d) incorporation of distributed generation; and (e) incorporation of nontraditional demands, such as electric vehicles;
- Review and evaluate system performance, which includes: (a) capacity loadings on each sub-transmission line, substation transformer, and distribution feeder for

forecasted peak loads vs. ratings; (b) reliability; (c) asset condition; and (d) power quality and voltage performance;

- Implement strategies for Planning Criteria, Area Strategy, and Asset Management;
- Identify system deficiencies that need addressing to ensure safe, reliable, resilient, and economic service to customers, which includes consideration of system flexibility in response to various contingency scenarios;
- Identify wires and non-wires solutions, reflecting the guidelines for non-wires solutions;
- Perform evaluation of wires and non-wires solutions;
- Decide on solutions that best meet distribution planning goals, informed by economic, reliability, feasibility, performance and environmental risks and impacts; and
- Develop proposals for system improvement projects.

Prepare Demand Forecast

As described in Section 2.0, the planning process begins with a forecast of demand, or load. The demand forecast at the system level is based on an econometric model that is developed on both a weather-normalized and weather-probabilistic basis. The explanatory variables in the model include historical and forecasted economic conditions at the county level, historical peak load data for each area, and a forecast of weather conditions based on historical data from a Concord, New Hampshire, weather station. Significant known or planned load additions and demand side management (“DSM”) programs are incorporated into the load forecast.

Evaluate and Identify System Deficiencies

Forecasted area growth rates are applied to each of the substations and feeders within the area. The distribution planner then adjusts the forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planner uses the forecasted peak loads for each feeder/substation under the extreme weather conditions to perform planning studies and to determine if the thermal and contingency capacity of its facilities is adequate. The Company evaluates its system performance based on the following criteria:

- Capacity – Planning criteria for normal and contingency load serving requirements are applied in concert with the thermal ratings of the facilities to identify capacity violations. Specifically, the distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact (normal conditions or "N-0") and N-1 first contingency conditions incorporating existing planning criteria.

- Asset condition – Asset condition assessments involve monitoring electric equipment periodically, and using the data collected from those inspections to determine the condition of each asset and if any mitigation is required to repair or replace the equipment.

- Voltage performance – The normal and emergency voltage to all customers shall be in line with limits specified by the State of New Hampshire and within the limits of ANSI C84.1-2016. The ultimate goal is to plan and operate the system such that delivery voltages are within the limits.

- Reliability – To measure system performance, Liberty utilizes several performance measures of reliability. These reliability indices include measures of outage duration, frequency of outages, system availability, and resilience (response time). Liberty's target is for its annual SAIDI and SAIFI[20] metrics to be below the five- year rolling average, excluding severe weather events. Liberty's goal is to modernize and

20 The system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI"), as defined further in Section 4.6.

improve the resiliency and reliability of its distribution system. This includes targeting pockets in the system that have experienced repeated interruptions and areas that are radially fed without any provisions for load transfers and have experienced long interruptions.

A distribution system that has adequate capacity and resiliency is one in which all customers, in the event of an outage, can be restored in a timely manner through system reconfiguration by means of manual switching or automatic restoring schemes. Adequate N-0 and N-1 capacity on power transformers, sub-transmission lines, and feeders are key design and operation objectives. The Company considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies. These criteria are described in the Company's Distribution Planning Criteria in Appendix D and summarized in Figure 4.3 below.

The planning criteria were updated in 2020. Refinements reflect Liberty's collaboration with Commission Staff to address concern that these were too conservative, such as raising the equipment rating "take action" limit from 75% to 100% on transformers and feeders, and raising the load at risk limit from 36 to 120 MWhr for supply lines and raising the load at risk limit from 60 to 180 MWhr for bulk transformers. Application of these criteria could result in more load at risk than previous criteria, which generally limited load at risk to below 2.5 MW pending the installation of a mobile substation.

Figure 4.3. Summary of Liberty Utilities Distribution Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	-Loading to remain within 100% of normal rating. -Voltage at customer meter to remain within acceptable range. -Circuit phasing is to remain balanced.	-Loading to remain within 100% of normal rating. -Voltage at customer meter to remain within acceptable range. -Circuit phasing is to remain balanced.	-Loading to remain within 100% of normal rating. -Voltage at customer meter to remain within acceptable range. -Circuit phasing is to remain balanced.
N-1 Contingency, results in facilities operating above their Long-Term Emergency (LTE) rating but below their Short-Term Emergency (STE) rating.	-Load must be transferred to other supply lines in the area to within their LTE rating. -Repairs are expected to be made within 24 hours. -Evaluate alternatives if more than **120 MWhr** of load at risk results following post-contingency switching.	-Load must be transferred to nearby transformer to within their LTE rating. -Repairs or installation of Mobile Transformer expected to take place within 24 hours. -For transformers larger than 10 MVA nameplate, evaluate alternatives if more than **180 MWhr** of load at risk results following post-contingency switching.	-Load must be transferred to nearby feeder to within their LTE rating. -Repairs expected to be made within 24 hours. -Evaluate alternatives if more than **16 MWhr** of load at risk results following post. (Guideline)
N-1 Contingency, which results in facilities operating above their Short-Term Emergency (STE) rating.	As Needed - Typically 15 min for OH conductors and 24 hours for UG cables.	Loads must be reduced within 15 minutes to operate within their LTE rating.	As Needed - Typically 15 min for OH conductors and 1-24 hours for UG cables.

Environmental considerations are incorporated into the planning and design of distribution facilities to ensure that all distribution activities are in compliance with environmental laws and regulations. Engineers receive Environmental Training and Guidance provided by the Environmental Engineer on a periodic basis. The training includes process steps for identifying environmental considerations related to project and work order preparation. During the planning, design, and estimating stages, it is the responsibility of the Engineering Department to identify and address any environmental considerations related to project or work order activities. The environmental evaluation assesses certain environmental conditions through discussions with the property owner or others, review of site plans, and/or field observations.

The planning criteria are applied to new installations and/or significant rebuilds and coordinated with other Company strategies such as substation replacement requirements or reliability initiatives. As existing assets reach the end of their useful reliable and economic life or the reliability of the system worsens, these strategies and criteria can be leveraged to bring system benefits to the customers.

Prioritize System Deficiencies

System deficiencies are evaluated and prioritized based on two criteria: (1) the impact of the system deficiency (including the number of customers and demand impacted by the deficiency), the loading (or percent of rated capacity) on the distribution facilities, and the safety and environmental impact; and (2) the likelihood that such impacts will occur, ranging from 1 in 100 years to each year. Liberty's prioritization of the system deficiencies is illustrated on page 3 of Appendix C. This prioritization process is used as a decision making guide to prioritize projects for inclusion in the capital budget based on risk, need, and alignment with Company goals and strategies.

Identify Traditional Solutions

Traditional solutions are Company initiatives that address system deficiencies through construction of new distribution facilities. Traditional solutions are evaluated in the form of individual project proposals that are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program typically consist of new or upgraded substations and new distribution feeder mainline circuits. Other projects in this program are designed to improve the resiliency and reliability of the network and improve the voltage, power quality, and power factor performance of the system. Traditional solutions are evaluated based on the project's scope, schedule, and overall cost effectiveness. Traditional solutions may also address asset replacement needs and reliability opportunities in conjunction with their impact on capacity.

Identify Non-Wires Solutions ("NWS")

Non-wires solutions ("NWS") are initiatives that may reduce, avoid, or defer the need for investment in distribution facilities through actions that reduce peak demand via targeted energy efficiency and load control programs, including electric energy storage technologies (e.g. batteries), or increase peak generation via distributed generation. These are also referred to non-wires alternatives ("NWA"). As described more fully later in this Section, NWSs include energy efficiency programs, demand response and load control programs, including electric energy storage, and DG programs that complement and improve operation of existing transmission and distribution systems, and that individually or in combination defer the need for upgrades to the transmission and/or distribution system.

The Company has integrated non-wires solutions in the distribution planning process. The goal is to seek the combination of traditional and non-wires solutions that best address capacity deficiencies in a cost effective manner considering the total cost and potential risks, including reliability, feasibility, performance, and environmental risks and impacts. As part of this process, a cost and risk analysis is conducted at a level of detail commensurate with the scale of the problems and the cost of potential solutions. Non-wires alternatives are screened for initial feasibility, according to the following criteria:

- Distribution deficiency needs to be addressed in no less than two years, allowing for development of potential non wires solutions;
- Distribution deficiency is not based on asset condition; and
- Traditional solutions, based on engineering judgement, will likely cost more than $0.5 million, providing sufficient cost savings to evaluate and implement a potential NWS.

These screening criteria result in a threshold of acceptance for non-wires projects stemming from the planning process that seeks to maximize the in-service life and utilization of existing assets. A non-wires solution is often determined to be infeasible or noncompetitive when one traditional solution can address a combination of issues that includes asset condition. For example, traditional solutions typically address a combination of load capacity, reliability, and asset condition issues. As with traditional solutions, specific non-wires solutions are evaluated based on the project's scope, schedule, and overall cost effectiveness. Refer to Strategy document DAS-016 Guidelines for Analysis of Non-Wires Solutions which describes Liberty's Project Evaluation Process and NWS Analysis Workbook found in Appendix D.

4.4 Tools to Evaluate the Distribution System

A variety of tools enable engineers to evaluate fault duty, coordination of protective devices, loading on all facilities, and voltage on all electrical system elements. The actual electrical configuration can be modeled in these tools, which allow the simulation of various system conditions and subsequent analysis. The primary modeling and analysis application tools are:

- The Synergi Electric 6.0 load flow program models supply system and distribution feeders. It also assists in determining fault coordination between protective equipment and the short circuit duty at all sub-transmission and distribution facilities.

- The Geographical Information System ("GIS") geographically maps customer locations, supply and distribution lines, and is used to determine demands at a service point level and/or a supply transformer level. Liberty has developed a process to extract the distribution attributes from the GIS system and the customer demand history from the Customer Information System (Cogsdale) to update the load flow model periodically. The Company is in the process of upgrading its GIS and expects to complete the data migration between 2021 and 2022.

- The Supervisory Control and Data Acquisition ("SCADA") system provides for monitored facilities, real time loading and voltage data and provides historical status, load and voltage data used to support various system planning activities.

- The Responder System serves as an outage management system ("OMS") and provides real time outage information and a consolidation and statistical analysis of reliability data. The Company is in the process of upgrading its OMS system to an Advanced Distribution Automation System ("ADMS"). Refer to Section 5.3 Liberty Utilities Distribution Grid Modernization Initiatives for details.

- The Quadra system serves as a work management tool, as well as an estimation tool. The Company is in the process of upgrading its enterprise resource planning tools which will result in improved business processes and project documentation. In addition, the Company will integrate the Distribution Design Studio (DDS) with the GIS and AMI application to improve the design and estimating processes.

Figure 4.4 below compares the proposed evaluation tools being implemented by Liberty with those currently in use.

Figure 4.4. Evaluation Tools: Liberty Utilities

Application	Proposed	Existing
Load Flow	Synergi Electric / CYME (to be determined)	Synergi Electric
Circuit Analytics	ArcGIS Dashboard / Smart M.Apps	None
Circuit Protection	ASPEN /Synergi Electric	Synergi Electric / Light-Table
Mapping/GIS	ArcGIS Desktop	ArcGIS 10.1
Energy Management	Telvent Oasis / ADMS Schneider	Telvent Oasis / Responder Explorer
Plant Information	SAP	Great Plains
Circuit Loading	ADMS / Pi	Telvent Oasis
Interruption Analysis	ADMS / ArcGIS Dashboard / Smart M.Apps	Responder Archive
Distribution Design	Distribution Design Studio (DDS)	ArcGIS Designer
Asset and Relay Management	Powerbase	Databases
DERMS	ADMS / Tesla	Tesla
Distribution Automation and Energy Conservation	ADMS / SEL DNA	Local DA Schemes / No Energy Conservation
Remote Applications	ArcGIS Survey 123 / TerraSpectrum	ArcGIS Survey 123

These existing or proposed tools could be revised, replaced, and/or updated once the Grid Modernization Program described in Section 5 is implemented by Liberty in New Hampshire.

4.5 Reliability Metrics

Since the total system is involved in supplying the customer, ensuring an acceptable reliability of service to all customers requires designing the supply and the distribution systems in an integrated manner, taking into account both capacity limitations and reliability of service initiatives to limit the interruption of energy delivery. The metrics that measure service reliability are SAIFI and CAIDI. The product of these two indices is the SAIDI per customer served. The Company measures its reliability performance using SAIDI and SAIFI, as required by the Commission. These indices are mathematically calculated as follows:

SAIFI= Number of Customer Interruptions ("CI") / Number of Customers Served ("CS")

SAIDI= Customer Interruption Durations ("CMI") / Number of Customers Served ("CS")

Where:

CI = Customers Interrupted

CMI = Customer Minutes Interrupted

CS = Customers Served (averaged over a period of time, such as month or year)

Liberty employs a five-year rolling average to determine annual targets for both SAIDI and SAIFI, excluding major storm events. The worst performing facilities, areas, or pockets are then targeted for reliability improvements.

The primary causes of distribution system-related outages in New Hampshire are tree contacts, equipment failure, storms, vehicle accidents, and animal contacts. To limit the number of customers affected by these outages the Company has implemented several infrastructure improvement programs including (1) fast feeder patrols,[21] (2) an inspection and maintenance ("I&M") program, (3) vegetation management, (4) a recloser program, (5) bare conductor replacement, (6) underperforming area mitigation, and (7) distribution automation ("DA")/grid modernization. As described in Section 5, the Grid Modernization Program will greatly enhance the ability of Liberty to improve planning, reliability, resilience, asset management, and operational efficiency to reduce the frequency and duration of customer outages when implemented.

Infrastructure Improvement Program

Liberty's Infrastructure Improvement Program includes the following initiatives and strategies to improve the resiliency of the distribution system:

- Inspection and Maintenance Program ("I&M") – The inspection and maintenance program identifies overhead equipment, including capacitors, reclosers, cutouts, crossarms, insulators, poles, guys and anchors, and switches that may be at the end of their useful lives and in need of replacement. Lightning protection upgrades include the installation of arresters, grounding, and equipment bonding. The I&M program is augmented with infrared inspections of line and substation equipment, substation equipment visual and operational inspections, and patrols of distribution supply facilities.

- Animal Intrusion Program – Additional actions include application of wildlife protective devices and substation animal fencing to limit animal intrusion on distribution equipment and at substations.

- Overloaded Transformer Program – This program targets replacement of overloaded transformers. Refer to DAS-006 Distribution Line Transformer Strategy for details.

21 As part of Liberty's I&M and Reliability awareness and proactive approach, the Company implements fast feeder patrols on the feeder mainlines to identify reliability issues before they pose a larger threat on the system. These are performed twice a year with patrols planned in the Spring and Fall.

- SCADA / Distribution Automation Program – These initiatives include improving resiliency in distribution system areas that have historically underperformed by implementing new SCADA devices with communication abilities to improve response time to outages. The DA program allows for the installation of automatic switching devices at selected locations to isolate faulted feeder sections, which can limit the number of customers affected by a fault on the electric distribution system. For details refer to DAS-002 Distribution Automation Strategy.

- Low voltage mitigation program – Voltage mitigation is planned for those areas that have experienced issues with low voltage. Mitigation includes the installation of capacitor banks and voltage regulators, voltage conversions, load balancing, and reconductoring.

- Underground Residential Development ("URD") refurbishment program – This program recommends URD cable for replacement and/or cable injection based on condition and/or poor operating history. For details refer to DAS-014 URD/UCD Cable Strategy document.

- Underground cable replacement program – This program recommends replacement of Company-owned underground cable based on condition and/or poor operating history. Typically all cable over 60 years of age is replaced and cables that have experienced three faults in a five year period are targeted for replacement. For details refer to DAS-013 Underground Getaway Cable document.

- Worst performing feeder program – This program tracks the worst performing feeders for the Company and recommends mitigation to address the main causes of interruption. For details refer to DAS-010 Poor Performing Feeder Strategy.

- Pocket of poor performance program – This program tracks the worst performing sub sections of distribution feeders and recommends mitigation to address the main causes of interruption. While these areas do not contribute greatly to the overall reliability performance of the Company, they are very significant to the customers in the pocket as they experience more frequent outages. For details refer to DAS-009 Pockets of Poor Performance Strategy.

- Bare conductor replacement – Spacer cable is installed in areas prone to tree outages that are too costly to rely on vegetation management practices alone to mitigate feeder lockouts. The application of spacer cable (a covered conductor resistant to tree related outages) significantly improves mainline circuit performance during windy and stormy conditions and affords protection against incidental tree-conductor contact at the end of the trim cycle, as well as contact resulting from branches falling from above the trim zone. Replacement of mainline bare conductor with spacer cable has proved highly beneficial. Spacer cable is an overhead primary distribution system that consists of covered conductors held in a close triangular configuration by spacers that are supported by a messenger and attached to a bracket on a pole. Spacer cable installations are recommended in heavily treed areas to mitigate the potential for outages caused by incidental contact of tree limbs to the primary conductors. In some instances, it may be possible to use tree wire on crossarms as a lower cost alternative to spacer cable.

- Single-phase recloser and trip saver program – Single-phase reclosers and "Trip Saver" cutouts target circuit segments that would realize reliability benefits from single-phase tripping and reclosing, as well as isolating faults down to the smallest single-phase segment possible. These devices are designed to interrupt circuit segments following a transient or temporary fault condition and then automatically restore the segment after a short period to allow the fault to clear. These devices not only improve reliability of service, but also avoid the cost of dispatching a troubleshooter or line crew to the scene to replace the fuse. Liberty uses single-phase reclosing devices at select locations of the distribution system to provide mitigation against transient faults as well as limit the number of customers impacted for permanent faults.

- Pollinator Program – The Company maintains off road distribution/supply lines in the communities of Lebanon, Hanover, Enfield, and Salem. Transmission corridors (often leased rights-of-way) convert terrestrial forest habitat to low-growing shrub/scrub/grassland habitat that is conducive to the safe and reliable transmission of energy. Periodic Utility Vegetation Management ("UVM") is required to maintain vegetation in a state that promotes the safe and reliable transmission and distribution for our customers. UVM seeks to establish and conserve early successional grassland habitat which has benefits beyond regulatory compliance. The Company is looking to return to Integrated Vegetation Management ("IVM") which simultaneously maintains infrastructure security and benefits wildlife conservation initiatives, including pollinator habitat. Currently the Company performs vegetation management using only mechanical means which promotes invasive woody material, thereby hampering visibility and movement along the corridor. Implementing IVM can discourage the aggressive, invasive woody material as well as invasive brush. By encouraging native local shrubby habitat and pollinator habit, it will require less resources in the future to keep the corridor safe and reliable while promoting natural and healthy wildlife and pollinator habitat.

Corporate Resiliency Improvement Initiatives

The Corporate agenda for Liberty and its utility affiliates is to move them into the 21st century by exploring opportunities to utilize newer technologies to provide the resiliency desired by customers. New technologies are being developed continuously and at a rapid pace. Customer demands are also changing based upon their experiences and interactions with many other companies that are utilizing new systems to serve their customers.

Liberty is committed to adapting to these changing consumer demands as described in the Company's witness testimony in Docket No. DE 19-197, Development of a Statewide, Multi-Use Online Energy Data Platform, and Docket No. DE 17-189, Petition to Approve Battery Storage Program. Liberty serves a wide variety of customers with geographic and cultural differences, and these issues and solutions can be assessed to determine the extent of the solution benefits across all regions. This variety allows for knowledge gained from pilot projects to benefit all customers. In addition, the Corporate agenda is not focused on a single commodity; therefore, knowledge gained from one commodity will be used to assess the potential benefits across all commodities and customers. As Corporate explores new technologies, Liberty will develop systems that are more resilient, sustainable, and customer oriented in an effort to create thriving communities.

The Corporate agenda targets the following initiatives for its New Hampshire Customers:

- Aging Equipment – This resiliency initiative aims to replace equipment that is over 50 years of age and/or has shown signs of deterioration. Liberty prefers a proactive approach to replace aging and/or deteriorated equipment prior to a failure because operating equipment until the eventual catastrophic end of life failure results in a major lengthy outage as well as creating a potentially dangerous situation within a substation or near the public.

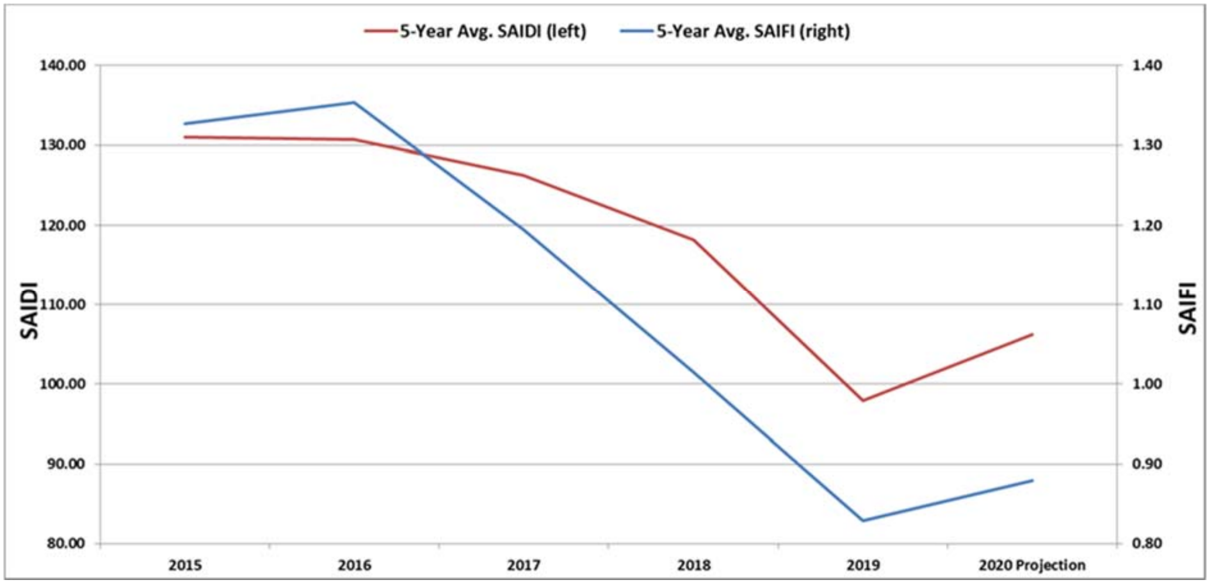
- Distribution Automation – This initiative aims to improve reliability performance and power quality, increase power system efficiency by automating processes for data preparation, optimal decision making and control of distribution operations.

- Animal Guarding – This initiative includes the addition of wildlife and asset protection equipment on company Substation and Distribution Line assets to improve reliability performance by reducing outages caused by animal contact.

- Substation Security - This initiative aims to improve the security at substations from outside threats such as theft, vandalism and cyber-attacks.

As shown in Figure 4.5 below, Liberty's reliability performance improved over the last five years, as demonstrated by the declining trend in SAIDI and SAIFI metrics since 2015.

Figure 4.5. Calendar Year Electric Reliability Trends, 2015–2020



4.6 Demand-Side Resources

Demand-side resources can be broadly defined as systems and controls in customer facilities that allow customers or the utility to reduce or control their use of energy. These generally consist of energy efficiency measures, demand response efforts, distributed generation, energy storage, and load controls. Energy efficiency measures generally produce savings whenever a particular load is running, while renewable distributed generation, such as wind and solar photovoltaic ("PV"), provides energy on an intermittent and uncontrollable basis. These types of resources are therefore considered passive resources. Other demand resources are dynamic and can be called on and utilized when economically justified; these are considered active demand resources.

Active demand resources, coupled with incentives such as demand response payments or dynamic time-of-use rate design, can create opportunities for customers to benefit from time-specific reductions in energy consumption and/or a shift in the hours that energy is consumed. Through the use of active demand resource technologies and appropriate incentive mechanisms, retail costs can more closely reflect the time varying cost to produce and deliver electricity, and result in behavior changes that create higher system efficiencies. Generally, this approach works in conjunction with smart metering systems that measure consumption data at regular intervals and provide such data directly to the customer.

As described previously, significant known or planned DSM programs, as well as DG installations and the Company's NHSaves energy efficiency programs, are incorporated into the load forecast and the Company's distribution planning process.

4.7 The Link between Demand Response and Planning

As of June 1, 2010, demand response resources participate on a comparable basis with generation in the regional FCM administered by ISO-NE. Such resources are able to compete with generation and imports, allowing New England to meet its resource adequacy requirements. On June 1, 2012, ISO-NE implemented changes to the demand response program to comply with FERC Order 745. FERC Order 745 requires active demand resources to be fully integrated into the competitive energy markets administered by ISO-NE.

Since Order 745 was approved, FERC has continued to conduct rulemakings to remove barriers to the integration of DERs with two additional Orders.

On February 15, 2018, FERC issued a Final Order 841, establishing guidance related to Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. The stated objective of Order 841 was to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by RTOs and ISOs in organized markets in North America. After a year of deliberation, FERC issued FERC Order 841a, denying a requested rehearing with respect to the lack of a State "opt-out" for local energy storage resources. Order 841a was appealed to the U.S. Court of Appeals for the District of Columbia in Docket No. 19-1142 in which oral arguments were heard on May 5, 2020, and the Three Panel Court delivering it unanimous opinion on July 10, 2020, supporting the Commission's order.

On September 17, 2020, FERC issued Final Order 2222 requiring RTOs/ISOs to coordinate with DER Aggregators, electric utilities, and local and state regulators to develop and submit compliance filings on July 19, 2021. This final rule enables these resources to participate in the regional organized wholesale capacity, energy, and ancillary services markets alongside traditional resources.

The development and ownership of active demand response resources will then be based on market incentives as perceived by the developers of such resources. The impact of these resources on Liberty's distribution system will depend on the response by these resources to ISO market signals and Commission guidance.

The Company is considering screening targeted demand response programs into its alternative analysis for system upgrades going forward, potentially leveraging the increasing amounts of demand response resources participating in the FCM and energy markets.

4.8 Incorporation of DG Facilities into Distribution Planning

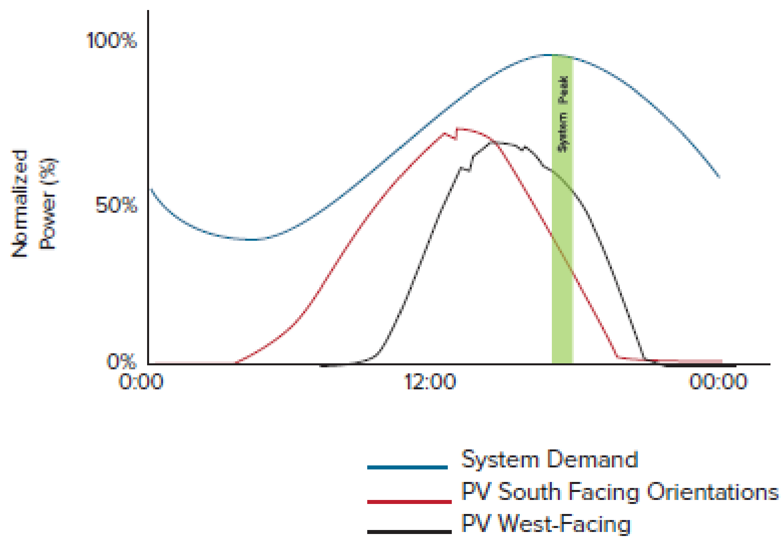
Liberty has experienced a significant increase in the amount of DG being interconnected to its distribution system, mostly through the installation of customer-sited solar generation.[22]

The decision to install and run DG systems is made by customers based on economic, environmental, and operational drivers. Because the Company does not control and cannot be assured of the development or operation of specific DG systems, their impact on system planning is typically experienced after they are in place. Once in place, the Company assumes DG output will continue at its future load projections, while at the same time recognizing its obligation in some cases to provide standby service to customers with DG systems. The Grid Modernization Program will substantially improve the ability of Liberty to incorporate these distributed resources safely and reliably by providing real-world, detailed system data for utility engineers and planners, along with real-time visibility of grid performance by utility operators.

The majority of the newer DG systems are renewable photovoltaic ("PV") and wind generation systems. The output of these systems is intermittent and, in general, uncontrollable. PV systems typically offer peak reductions during summer peaks in the range significantly below their ratings, because summer peaks typically occur in the mid-afternoon on the hottest days when the sun is not at the optimal angle and PV panels are less efficient due to ambient temperatures. Figure 4.6 below, as published in a 2013 study from the Rocky Mountain Institute, illustrates this effect:

22 Utility-owned distributed generation is discussed in Section 5.

Figure 4.6. Illustrative Example of the Effect of PV positioning on System Peak[23]



PV typically does not impact winter peak loads, because winter peaks occur in the evenings. Wind resources are also highly variable and may not impact peak loads the Company expects to experience at any given location due to this variability. It is likely that additional combined heat and power generation may be installed as fuel prices increase and technologies become more mature. However, in many cases such systems run coincident with thermal requirements that are heavily weighted towards the winter months and therefore may not be able to significantly impact summer peak loads. To the extent that DG does impact peak loads, the Company incorporates their historic output into system planning going forward through the distribution planning process discussed in Section 4.

The interconnection process for customers to install and run DG in parallel with Liberty's distribution system is dependent on the DG system's size and technology. DG systems with

23 Source: Rocky Mountain Institute, "A Review of Solar PV Benefit and Cost Studies," 2nd Edition, September 2013, at 30.

power ratings of 100 kW or less may utilize a simplified application process to facilitate interconnection with the Company's electric power system. Larger DG systems proposing to interconnect with the Company must undergo a more robust application process and must supply sufficient technical information to allow the Company to determine the scope and cost of any potential modifications to the Company's distribution system required to accommodate the DG system. This typically requires an engineering study performed by the Company at the DG developer's cost. Safety, system operation and protection, and service quality are the Company's primary considerations in such studies. For larger DG systems, the Company takes into consideration such parameters as voltage and frequency fluctuations, protective device coordination, available fault duty impact, potential for islanding, and ability to automatically and manually isolate the DG from the system.

4.9 Smart Grid

RSA 378:38, IV, requires a utility's LCIRP to include an assessment of "Smart Grid" technologies. For the purposes of this LCIRP filing, Liberty defines smart grid technologies as digital technology that allows for two-way communication between the utility and its customers, and the application of computer-based remote control and automation technologies to electric transmission and distribution systems.[24] Smart Grid consists of

24 As defined by the U.S. Department of Energy's definition of "smart grid." *See,* U.S. Department of Energy, http://energy.gov/oe/services/technology-development/smart-grid, and https://www.smartgrid.gov/the_smart_grid/smart_grid.html.

controls, computers, automation, and new technologies and equipment working together, which respond digitally to quickly changing electric demand conditions.[25]

Smart grid technologies consist of grid-facing (interfacing primarily with the utility's distribution system) and customer-facing (interfacing primarily with customers) technologies and applications. These include advanced digital versions of investments currently in place, such as meters, as well as newer technologies to provide customers information and tools to control energy usage. "Smart grid" technologies also include the communication network and systems to automate and control the technologies and applications.

A 2011 report by the Electric Power Research Institute ("EPRI") estimated that, industry-wide, smart grid investments could generate 2.8 to 6.0 dollars in benefits for every dollar in net investment (that is, above the investment needed to maintain the current system and meet electric load growth). However, total industry costs of a fully implemented Smart Grid were estimated to be between approximately $340 billion and $475 billion, or approximately $17 to $24 billion per year over the next 20 years.[26] Accordingly, although smart grid technologies could provide significant benefits, the substantial investment required to achieve those benefits must also be carefully considered.

In 2019, Liberty engaged a "Smart Grid" consulting company, CMG Consulting LLC, to work with our planners and engineers to evaluate the many potential "smart grid" technologies, including a detailed cost/benefit analysis of the technologies that would provide

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25 https://www.smartgrid.gov/the_smart_grid/smart_grid.html.

26 *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*, EPRI, 2011 Technical Report, at 1–4.

the maximum benefits for Liberty's customers in New Hampshire. This Grid Modernization report was completed in June 2019 and was updated in November 2020 and serves as the basis for the Grid Modernization Program described in Section 5 of this LCIRP. The CMG Grid Modernization report is provided in Appendix E to this LCIRP, and provides the economic basis for concluding that certain smart grid technologies selected by Liberty will provide substantially more benefits than costs to its customers.

Smart grid investment may require regulatory changes. For example, some smart grid technologies rely on innovative rate structures (i.e., time of use rates), which would require approval through additional regulatory proceedings. On February 12, 2019, the Commission Staff submitted its recommendation on grid modernization in Docket No. IR 15-296 and proposed that the LCIRP be replaced by a new submission, an Integrated Distribution Plan. After providing a round of public comment, the Commission issued Order No. 26,254 which provides acceptance of Staff's recommendations. While this Grid Modernization Order is on hold pending a motion for rehearing, Liberty has attempted to incorporate the spirit of this order into this LCIRP. Liberty will continue to be an active participant as the Grid Modernization investigation progresses.

4.10 Capital Investment Plans

System capacity, performance, asset, and reliability and resiliency improvement capital projects are identified as a result of reviews and the annual capacity planning process. The adopted solutions are cash flowed by year and entered into the five-year capital investment plan along with other capital initiatives such as new business, public requirements, response to damage and failure, and other mandatory category projects. The five-year plan is then optimized according to project need, risk management, and availability of resources. Once initiated, multi-year projects are typically progressed to completion with their system solutions incorporated into current and future studies. The annual budget of capital projects greater than $100,000 is filed with the Commission as part of the Form E-22 filing required pursuant to Puc 308.07.

Figure 4.7 summarizes the Company’s five-year capital investment plan totaling $120 million, and provides the definition for each of Liberty’s budget categories.

Figure 4.7. Summary of 5-Year Capital Investment Plan and Budget Category Definitions

Category	2022-2026 Capital Budget ($)	2022-2026 Capital Budget (%)	Project Prioritization Category	Definition
Mandated	$22.6	18%	Mandated / Impending regulatory obligations / Damage/Failure Facilities relocations	Programs that are required by Statutes, Codes, etc. that have limited, if any, discretionary component relative to meeting a prescribed program. These programs would be related to specific obligations that have been imposed on the utility to carry out the project
Growth	$28.3	23%	Growth	Capital needed to support servicing growth in the customer base
Regulatory Programs	$0	0%	Regulatory programs with mechanisms	Programs such as the Tesla Battery Program.
Discretionary	$73.3	59%	Discretionary projects	All other programs with a business case justification
5-Year Total	$124.2	100%		

4.11 Non Wires Solutions Integration Process

The Commission ordered the Company "to provide a more comprehensive discussion of how Liberty assesses non-wires alternative in its distribution planning" and to "explain in greater detail, how demand- and supply-side options for distribution planning are integrated by Liberty as part of its planning process." Order No. 25,625 at 8 (Jan. 27, 2014). In doing so, the Commission recognized that improvements in energy efficiency, localized distributed generation, and demand response programs, including electric energy storage, have the potential to reduce the need for capital investments in electric system transmission and distribution ("T&D") system upgrades and expansion, while providing obvious benefits to participating customers, and to all customers on the electric system through lower rates.

In some cases where the expansion of the T&D system is required on a localized basis to meet increased demand, there may be alternatives that reduce demand at a potentially lower cost than T&D infrastructure investments. When non-wires alternatives can be provided at a lower cost and risk than traditional infrastructure, these programs can enhance the Company's ability to provide service at the lowest reasonable cost and risks to customers

4.12 Liberty NWS Planning Process

Liberty has incorporated the evaluation of Non-Wires Solutions into its ongoing system planning process as described in this section. Refer to strategy document DAS-016 Guidelines for Analysis of Non-Wires Solutions. This initial screening was modeled after Unitil's Cost/Benefit Analysis Spreadsheet presented in their 2020 Least Cost Integrated Resource Plan.

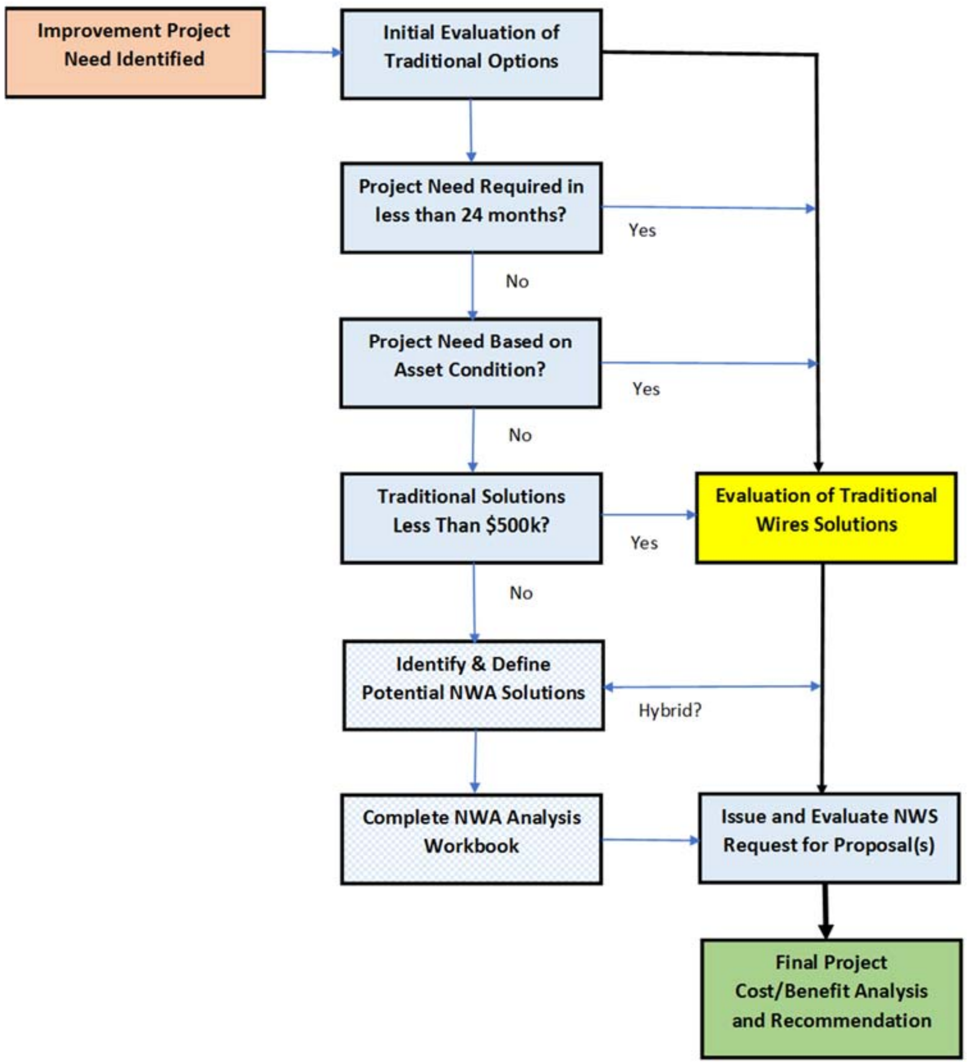
To ensure proper coordination and communication at all levels of the organization, the cross-functional team includes representatives from electric supply planning, electric system planning, energy efficiency administration, system standards, policies and codes, and regulatory. With the planning team in place, the Company is prepared to evaluate non-wires solutions on an equal basis as traditional infrastructure.

As described in this document, the Company applies a set of screening criteria for evaluating non-wires solutions specific to its service territory and size of its operation. The process begins with demand forecasts that are prepared in sufficient geographic detail to make non-wires solutions viable. Demand forecasts are prepared for each substation, sub-transmission line, and feeder under extreme weather scenarios to determine if capacity is adequate to meet demand under normal and contingency configurations. Planning criteria of normal and contingency configurations are then applied in concert with the thermal ratings of the facilities to identify if and when any of the planning criteria are violated. The geographic detail of the starting point enhances the feasibility of non-wires solutions, and the operating characteristics ensure that the deficiency is not based on asset condition.

Next, the planning group develops wires and non-wires alternative proposals that address those instances when and where the planning criteria are violated. The group then performs a financial analysis of each proposal and prioritizes them.

Finally, the group submits the proposals as part of the Company's capital plan. Figure 4.8 below summarizes Liberty's NWS process flow.

Figure 4.8. Liberty NWS Evaluation Process



Two important aspects of the comparative evaluations involve the load profile of the solutions relative to the demand on the system and the financial and risk analysis to put the alternatives on an equal footing. The T&D system can experience peak demand at different times of the day, in different geographic locations, and during different seasons. The ability of a non-wires alternative to reduce, defer, or eliminate a traditional infrastructure investment, therefore, depends on the alignment of hour and season of the peak demand, with the hourly and seasonal profile of the non-wires alternatives savings. The non-wires alternative solutions are designed to include those measures that provide a saving profile that best matches the demand profile it is intended to reduce. The Company also compares a solution's risk profile (for both wires and non-wires) based on a number of risk factors, including reliability, feasibility, performance, and environmental risks. For each potential traditional and non-wires solution, each of these risk factors is rated on a scale of one to four, then summed to calculate a total project score for each Traditional and NWS options. Figure 4.9 below provides a summary of each of the risk factors.

Figure 4.9. Project Risk Factor Summary

	Step	Description
1.	Reliability	The risk that a potential solution can or cannot meet customer reliability requirements.
2.	Feasibility	The risk that a potential solution is commercially available and can be accomplished in time to meet the needs of customers
3.	Performance	The risk that a potential solution will perform as predicted including the amount of "real-world" operational data for the proposed technology
4	Environmental	The risk of environmental impact of each proposed solution

Liberty's financial evaluation of the non-wires alternatives and wires solutions relies on the Total Resource Cost test.

The final result of the total cost for each non-wires and wires alternative solution is, therefore, the calculation of the net present value of both capital expenditures and ongoing operations and maintenance costs. These results, along with the ranked risk assessment allow the group to compare and prioritize the solutions based on their relative net benefits.

Strategy document DAS-016 Guidelines for Analysis of Non-Wires Solutions provides an illustration of the process Liberty would undertake to evaluate and implement a traditional and non-wires alternative solutions using a new NWA Analysis Workbook completed for improvements that meet the screening criteria for consideration of non-wires solutions.

4.13 Company-owned Distribution Generation

In addition to customer owned distributed generation, the Company also recognizes the potential value of Company-owned installations, as allowed for in RSA Chapter 374-G. That statute makes Liberty eligible to have up to 6% of its total distribution peak load (approximately 12 MW) in utility-owned DG. The pursuit and application of such generation would be driven by consideration of the factors described in RSA 374-G:5, including:

- The targeted reduction in feeder or area peak demand (in kW) as well as the timing for the reduction;
- The availability of potential sites on the feeder for utility owned generation; most likely open space, agricultural land, or unused industrial/commercial land or rooftops;
- The size, orientation, and type of DG, as well as the estimated capacity factor of the installation;
- Feeder engineering, operating, and performance considerations specific to the site, the feeder, and the size/type of installation;

- The installation cost on a dollars-per-kilowatt and total cost basis;
- The ability to permit the site according to local codes and requirements;
- The degree of acceptance and support exhibited by the local community for such an installation;
- Affirmation of the recovery of installation costs, including fair return on investment, through the appropriate tariff;
- The benefits to any specific customer as well as to all other customers; and
- The amount of investment to be made by Liberty and, for customer-sited distributed generation, the amount to be invested by the customer.

The RSA 374-G process enables the Company to evaluate Company-owned or contracted DG options on an equal footing with other wires and non-wires alternatives when selecting the least cost alternative to reducing demand on a particular feeder or group of feeders serving an area.

Should Liberty determine that the benefits of a particular company-owned distributed generation project outweigh the project's cost, the Company could submit a filing to the Commission pursuant to RSA 374-G, as was done in the Docket No. DE 17-189 Petition to Approve Battery Storage Pilot Program.

4.14 Best Practices for Non-Wires Solutions

In general, NWAs are intended to reduce demand via targeted energy efficiency and load control programs, including electric energy storage technologies, or increase peak generation through distributed generation measures in specific constrained geographical areas in such a way that investments in utility transmission and distribution systems can be reduced, deferred, or eliminated. This is beneficial to the system as a whole only if NWSs are ranked higher than infrastructure expansion. These benefits are initially determined using the Project Evaluation Workflow presented in DAS-016 Guidelines for Analysis of Non-Wires Solutions. Another important element of designing non-wires programs is to match the hourly and seasonal load profile of the energy efficiency measures to the profile of the demand on the system. If the efficiency does not occur at the time that it is needed, it might not solve the need for the additional capacity. The level and mix of the energy savings measures are important determinants of whether the T&D deferral, reduction, or elimination is possible and for how long.

Liberty reviewed non-wires solutions implemented in other jurisdictions. Based on the documented experiences of other electric utilities, some features of successful non-wires alternative implementation processes include:[27]

- Leadership support on the value of non-wires alternatives;
- Cross-functional planning teams that include, in addition to system planning engineers and electric system operators, energy efficiency and demand management program administrators, community out-reach personnel, and financial analysts;
- Starting small and employing "modular" strategies that can be scaled with ease;
- Evaluation of non-wires solutions as part of the routine T&D system planning process; and
- Screening criteria for non-wire solutions in appropriate situations.

27 See "*Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*", Neme, Chris and Grevatt, Jim, Energy Futures Group. Presented to the Northeast Energy Efficiency Partnerships, January 9, 2015, at 55–61.

4.15 Grids Needs Assessment

In the November 19, 2018, settlement in Docket No. DE 17-189, the battery storage pilot docket, Liberty agreed to provide a "Grid Needs Assessment" as part of its next LCIRP filing. Specifically, that settlement stated:

> To that end, Liberty shall provide a detailed grid needs assessment within its next LCIRP. That grid needs assessment shall describe all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. The grid needs assessment shall be available in spreadsheet format and shall include the following attribute-based columns and content: (1) Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need; (2) Distribution service required: capacity, reliability, and resiliency; (3) Anticipated season or date by which distribution upgrade must be installed; (4) Existing facility/equipment rating: MW, kVA, or other; and (5) Forecasted percentage deficiency above the existing facility/equipment rating over five years. Upon filing of the LCIRP and associated grid needs assessment, Commission Staff, the OCA, and Liberty will review planned capital investments to identify candidates that may be appropriate for NWA opportunities.

Settlement Agreement at 16. Figure 4.10 below provides information on the grid needs estimated at greater than $250,000 as identified for Substations and Distribution Lines. This table excludes projects that are needed due to asset condition, along with other capital initiatives such as new business, public requirements, response to damage and failure, and other mandatory projects.

1 **Figure 4.10. Needs Grids Assessment Results Part 1**

Facility/ Location (1)	System Granularity of Grid Need (1)	Capacity/ Reliability/ Resiliency (2)	Anticipated season or date by which distribution upgrade must be installed (3)	Equipment Rating (4)	Forecasted percentage deficiency above the existing facility/equipment rating 2025 (5)	Additional information:
14L2 Burns Rd, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2021	N/A	N/A	
7L1 Route 4, Enfield	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2021	N/A	N/A	
14L1 Bridge St, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2023	N/A	N/A	
18L3 S Policy St, Salem	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2025	N/A	N/A	
18L2 S Policy St, Salem	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2022	N/A	N/A	
14L2 Marsh Rd, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2022	N/A	N/A	
1L3 Mascoma St, Lebanon	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2023	N/A	N/A	
12L2 Watkins Hill Rd Phase 1, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2021	N/A	N/A	
12L2 Watkins Hill Rd Ph. 2, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2022	N/A	N/A	
12L2 Watkins Hill Rd Ph. 3, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A	
9L3 Range Rd - W Shore Rd, Windham	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A	
12L1 Rt. 123A, Alstead	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2024	N/A	N/A	

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Figure 4.11. Needs Grids Assessment Results Part 2

Facility/ Location (1)	System Granularity of Grid Need (1)	Capacity/ Reliability/ Resiliency (2)	Anticipated season or date by which distribution upgrade must be installed (3)	Equipment Rating (4)	Forecasted percentage deficiency above the existing facility/equipment rating 2025 (5)	Additional information:
39L2 Plainfield Rd Phase 1, Lebanon	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2025	N/A	N/A	
6L3 S Main St, Hanover	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2024	N/A	N/A	
1L2 Meriden Rd Phase 2, Plainfield	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2024	N/A	N/A	
16L1-6L3 Goodfellow Rd Tie, Hanover	Construct circuit tie 16L1 to 6L3 and implement DA	Reliability / Resiliency	2023	N/A	N/A	
7L1-7L2 Lockehaven Rd Tie, Enfield	Construct circuit tie 7L1 to 7L2 and implement DA	Reliability / Resiliency	2024	N/A	N/A	
21L4 New Feeder, Salem	Construct new 21L4 and implement DA	Reliability / Resiliency	2025	N/A	N/A	
14L5 New Feeder, Salem	Construct new 14L5 and implement DA	Reliability / Resiliency	2025	N/A	N/A	
12L1 Transformer, Walpole	Construct new 40L2 and circuit tie with 12L1 to mitigate contingency loss of 12L2 feeder	Reliability / Resiliency / Capacity	2025	9.6 MVA	133%	Does not violate 16 MWhr guideline. Voltage violations
12L1 Transformer, Walpole	Add 2nd Transf. and 115 kV T-Line at Michael Ave Sta. to mitigate contingency loss of Michael Ave Transf. #1	Reliability / Resiliency / Capacity	2025	9.6 MVA	190%	Does not violate 180 MWhr criteria / Voltage violations / >24 hr. mobile inst.
16L4 Feeder, Lebanon	Construct new 16L7 to supply new customer expansion.	Resiliency / Capacity	2021	11.7 MVA	116%	
11L1 Feeder, West Lebanon	Construct new 39L4 to resolve forecasted overload with new commercial development	Resiliency / Capacity	2025	10.9 MVA	105%	

5. DISTRIBUTION GRID MODERNIZATION PROPOSAL

5.1 Introduction

We are witnessing a revolution in the way electric power is transmitted from generators and distributed to end-use consumers. It is characterized by the convergence of information, data management, and modular electricity generation and delivery technologies.

In the coming years, energy demand is projected to increase due to further evolution of electrification of our society, a significant percentage of the industry's skilled workforce is scheduled to retire with job experience and knowledge that cannot be replaced with a 1:1 ratio, and global demands for decarbonization challenge the stability of energy costs and reliability. Many regulators favor increased industry competition, information-armed consumer groups are making greater demands about pricing and other issues, and governments at home and abroad are pressing for cleaner, more reliable energy. These dramatic changes in the business environment are encouraging utilities to take advantage of key technologies to improve the efficiency, quality, reliability, and cost of supplying services.

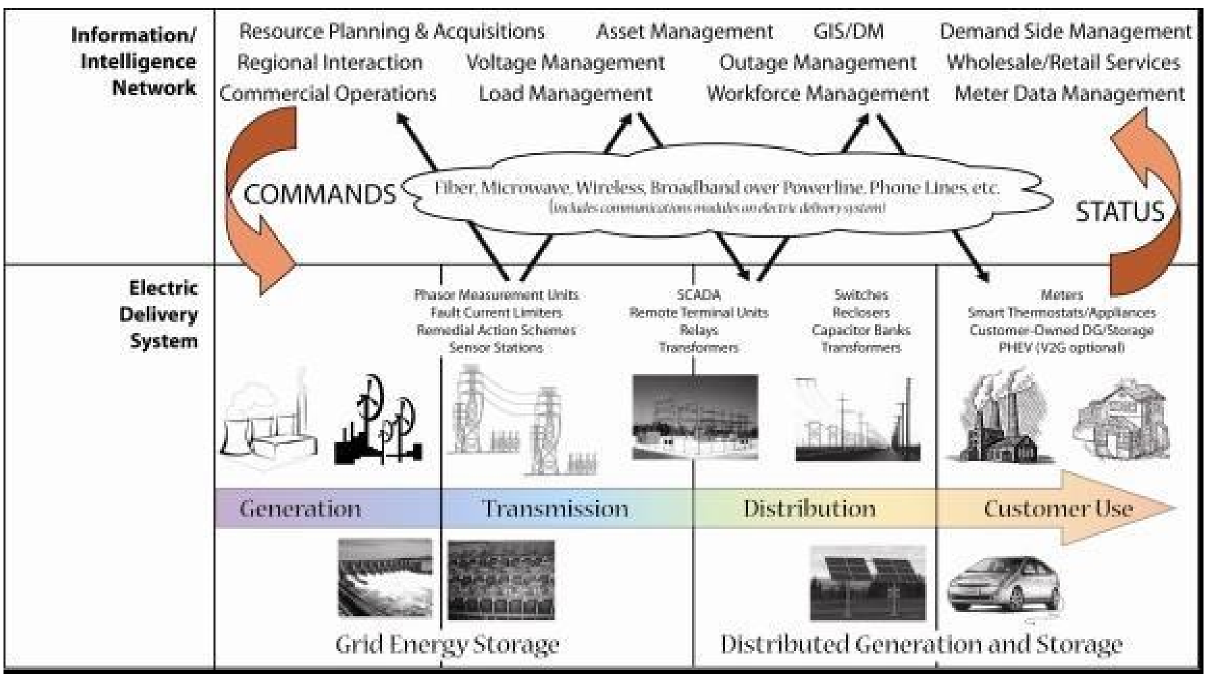
The movement toward Grid Modernization involves the deployment of "intelligent" or "smart" utility infrastructure technologies that weds communications, data, hardware, and other technologies into a future "self-healing" grid. As technologies advance, the possibilities for this modernization effort expand as well, not just in having more advanced electric components, but also the consumer devices that get plugged into the grid. Renewables and distributed generation have the potential for adapting utilities to carbon-constrained environments. New storage technologies could save cheap and/or renewable generation for use in peak periods. Communicating between devices or sensors improves operations, optimizes asset use, increases reliability and safety while providing stakeholders with the information they need to make better decisions. This could mean everything from customers choosing to use electricity differently to utility personnel modifying operating activities. At the end of the day, Grid Modernization will redefine the way in which utilities operate and electricity is consumed in the future.

The New Hampshire Public Utilities Commission, in Order No. 26,358 (May 22, 2020), provided further guidance on how the state's electric distribution utilities need to plan to accommodate new technologies into its Least Cost Integrated Resource Plan (LCIRP). Although this order is on hold while the Commission addresses a motion for rehearing, Liberty has attempted to incorporate the spirit of the order into this LCIRP.

5.2 Network Architecture

At a high level, this modernization effort is made up of two parallel networks: the electric grid itself and the intelligence behind it. The electric grid includes all of the equipment required to generate and distribute electricity as well as the control devices attached to it. The intelligence network consists of the core communications, data management systems, and the applications that process data from the devices. What makes the grid "smart" is its ability to communicate seamlessly between these two parallel networks at every level including consumption by customers. Enhanced communications and control capabilities will allow distribution delivery systems to accommodate and support the rapidly evolving needs utilities and their customers have for increased reliability, efficiency, and environmental quality.

To successfully incorporate these technologies, the electric grid will need to support real-time data collection from all end points through a myriad of 'smart devices'; reliable, secure, real-time, high bandwidth communications networks to deliver information and facilitate device automation and remote control; and IT systems including databases, decision support systems, and control applications.



From a technology point of view, Grid Modernization is all about applying new technologies to reduce the cost, increase efficiency and improve the quality and reliability, of electric service. The Department of Energy has identified five key technologies that are the essence of the smart grids, and we have adopted this same perspective to elaborate a definition of Grid Modernization.

The DOE's five sets of technologies are as follows:

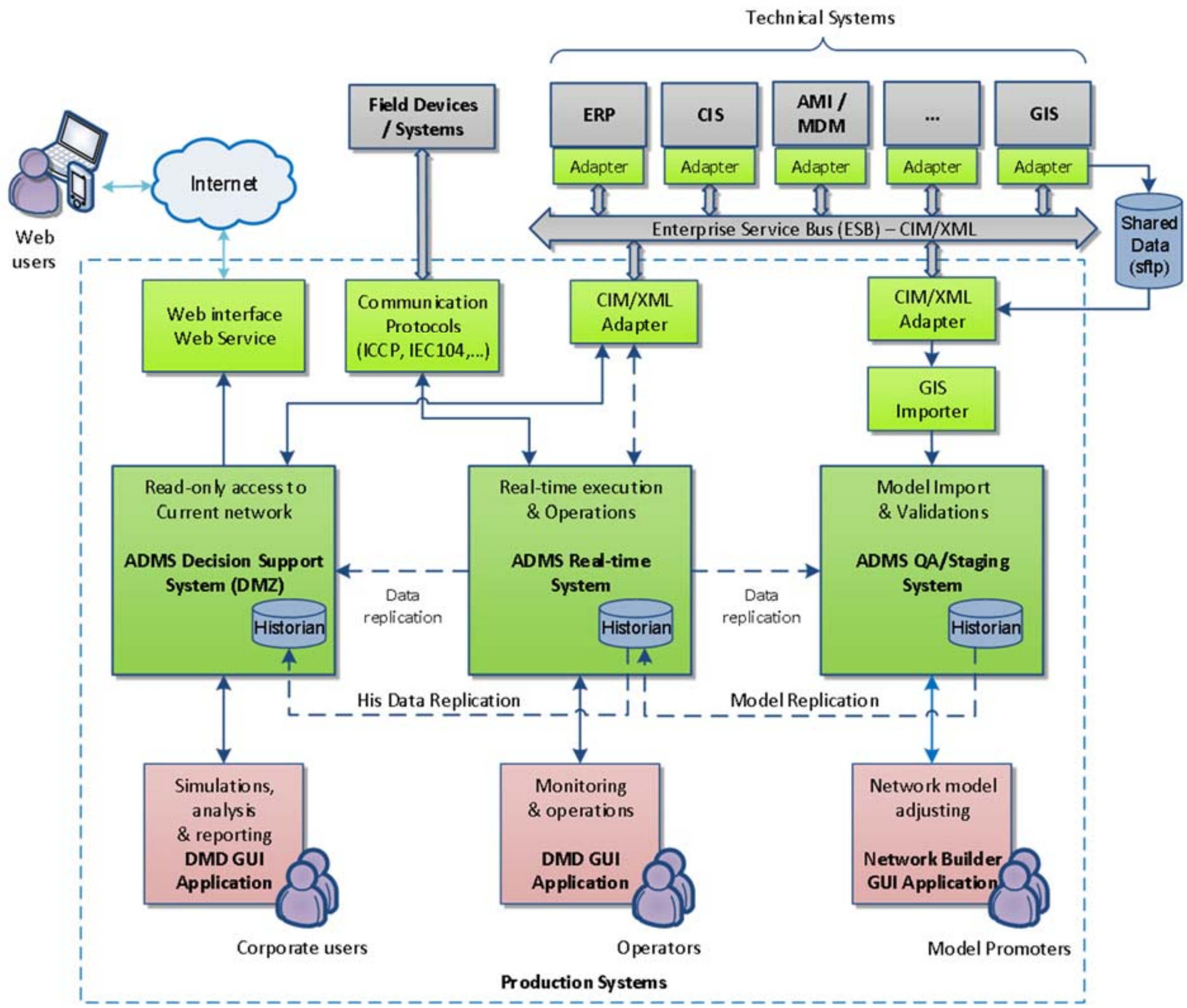
- Integrated Communications – Connecting all the components of the electric grid through open architectures, which will provide for real-time information and control of the grid and thus allow every component to both 'talk' and 'listen.'
- Sensing and Measurement – Devices that sense and measure various aspects of grid operation and thus support faster and more accurate response such as remote monitoring of voltage, current, phase angles, etc.
- Advanced Components – Applying the latest technologies for superconductivity that reduce line losses, storage that allows for the use of off-peak generation to meet peak period requirements, and power electronics and diagnostics that will improve the operation and efficiency of the grid.
- Advanced Controls – Monitoring essential components in real-time and thus enabling early detection and rapid diagnosis in order to provide precise solutions appropriate to any event before they can cascade into bigger problems.
- Improved Interfaces and Decision Support – Improving human decision making by providing grid operators and managers with the information and ability to operate as visionaries when it comes to seeing into their systems.

5.3 Liberty's Distribution Grid Modernization Initiatives

An assessment of the current state of operations at Liberty was conducted by CMG Consulting with key Liberty subject matter experts, and by evaluating current industry trends. The Company's Grid Modernization Report was developed in 2019, updated in 2020, and is included in Appendix E of this LCIRP. The following use cases were evaluated and selected to be implemented in Liberty's distribution systems:

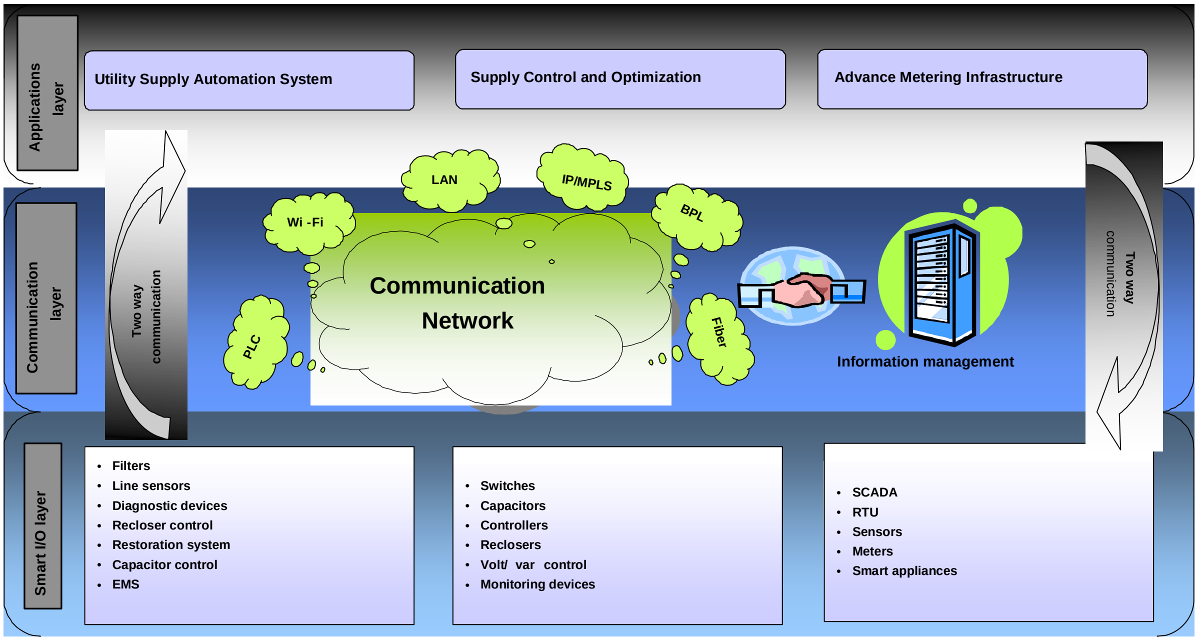
Advanced Distribution Management System (ADMS)

An ADMS is the software platform that supports the full suite of distribution asset management and optimization programs. The ADMS will include functions that integrate AMI and automate outage restoration, and will optimize the performance of the distribution grid. ADMS functions that are being developed include fault location, isolation, and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles. The ADMS real-time solution will replace the legacy OMS and will provide a platform tailored to the operations required for the distribution grid with a fully integrated solution including full GIS, OMS, DMS, SCADA, DERMs, with Advanced Application functionality and a single network model that is maintained with a common set of Data Engineering Tools. Refer to the figure below for an illustration of how ADMS will integrate with other assets and systems.



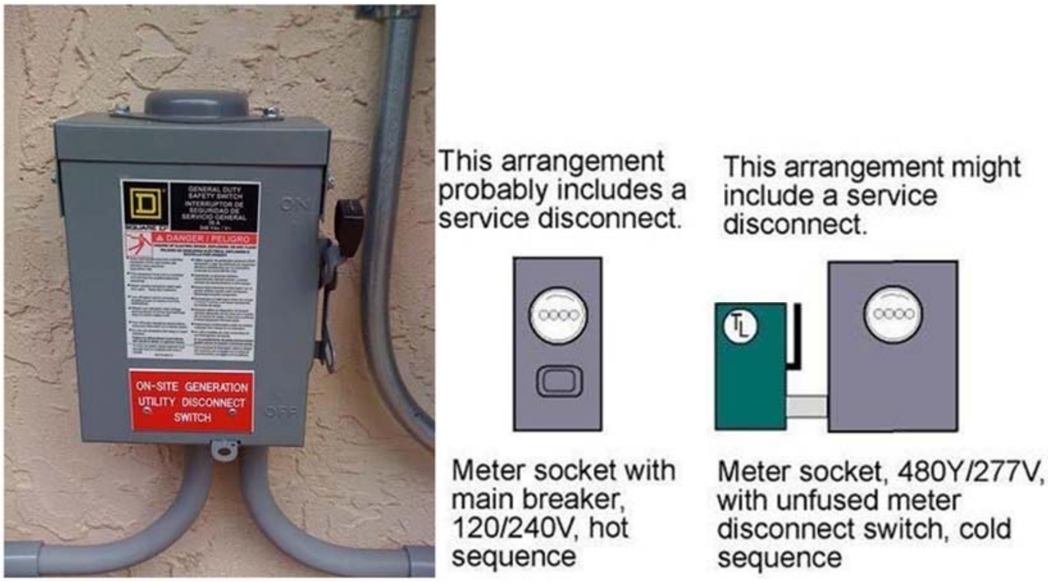
Automated Metering Infrastructure

The components of a successful Automated Metering Infrastructure ("AMI") deployment include a robust communications channel, supporting software, and bidirectional meters capable of measuring 15 minute intervals. The advanced meters deployed across the distribution network also function as grid health monitors by reporting back outages and line conditions related to voltage and current. In combination, the AMI and ADMS systems serve as the backbone for the entire grid modernization effort.



Connect/Disconnect

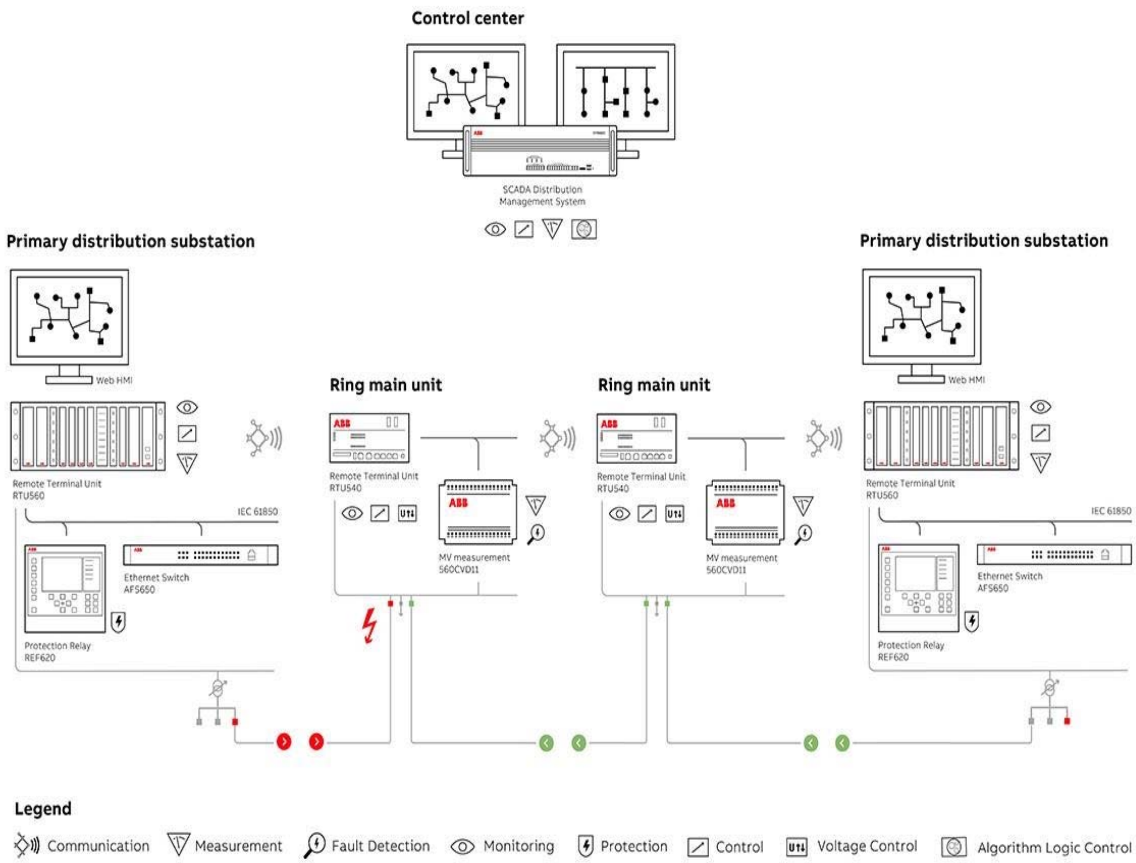
Remote connect/disconnect capabilities are enabled by retrofitting existing meters with a collar, or by choosing a remote disconnect capable meter for selected deployments. The ability to remotely disconnect and reconnect energy flow enables labor savings, revenue assurance, and improves service quality. Benefits include revenue improvements and cost reductions.



Fault Detection

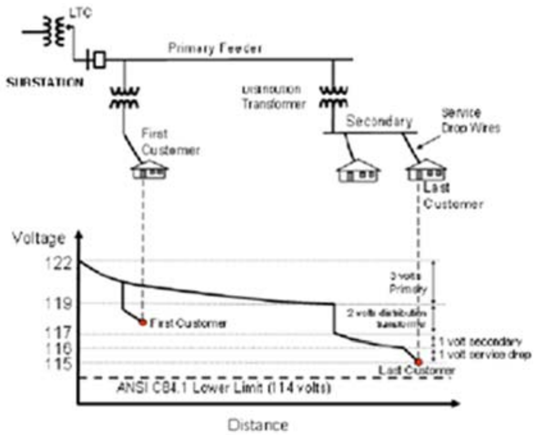
Significant benefits arise from improved capabilities for responding to electrical faults in the utility's electric delivery system. The automation schemes will provide improved capabilities to activate protective relays (e.g., tripping substation feeder breakers to protect fuses) and to instantly switch circuits, as needed, to protect the system. Fault detection would provide improved controls for automated balancing, shedding, and transferring of loads; and it would provide advanced decision support systems for human operators.

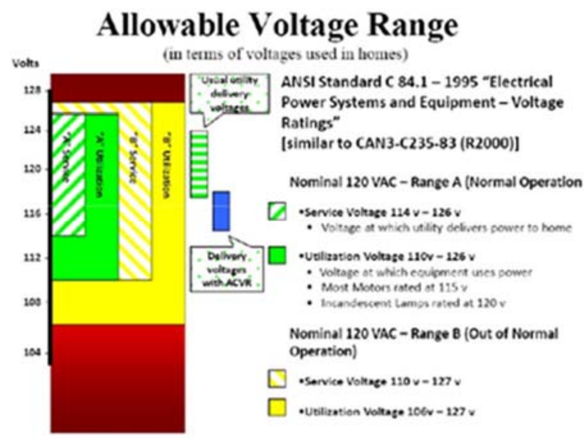
ADMS, AMI, and Outage Management System (OMS) integration allows proactive response to outages rather than waiting for customers to call in, minimizing customer re-calls and eliminating the need to phone customers to verify restoration. Real-time communication links that deliver outage and restoration alarms will send high-priority message when service is out. Fault detection, isolation, and recovery (FDIR) is a subfield of control engineering which concerns itself with monitoring a system, identifying when a fault has occurred, and pinpointing the type of fault and its location.



Conservation Voltage

Voltage management offers the potential for electric utilities to utilize controls over the voltage levels of the distribution network to enable real operational gains. While utilities typically operate in the upper range of the ANSI voltage band under normal circumstances, voltage can be compressed during key periods in a way that benefits utilities and consumers. Numerous studies have shown that for each 1% drop in voltage levels, energy consumption for residential and commercial loads can be reduced by 0.8%, although this value can vary depending on load mix and distribution system configuration.



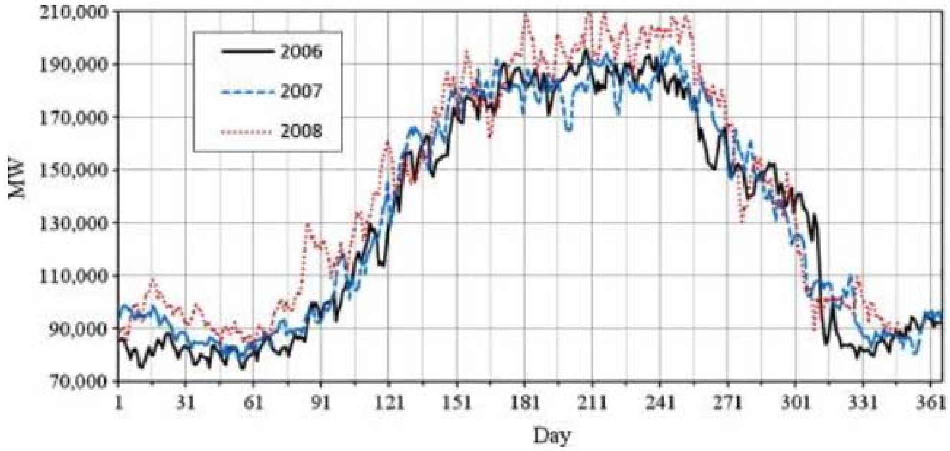


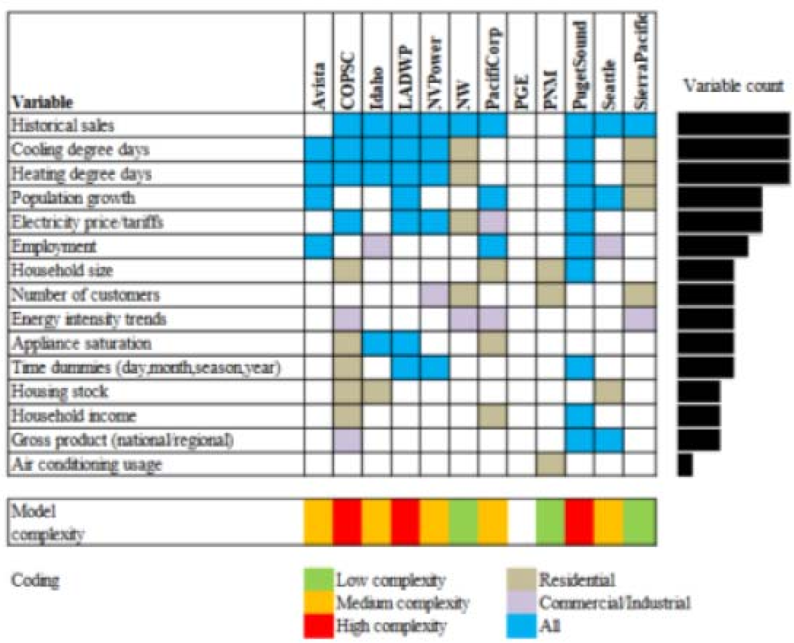
Load Forecasting

Load forecasting is a vital process in the planning of electricity industry and the operation of electric power systems. Accurate forecasts lead to substantial savings in operating and maintenance costs, increased reliability of power supply and delivery system, and correct decisions for future development. Automated load forecasting tools enable utilities to remove the dependence on purely manual processes for forecasting and planning.

Industry analysts have estimated that load predictions have consistently over-forecasted by 1% each year, which implies that a ten-year utility forecast could result in a 10% over-estimation of demand, leading to thousands of dollars in unneeded investment. Automating processes with more granular data can support an improved load forecast accuracy.

See the following illustrations for enhanced load forecasting.

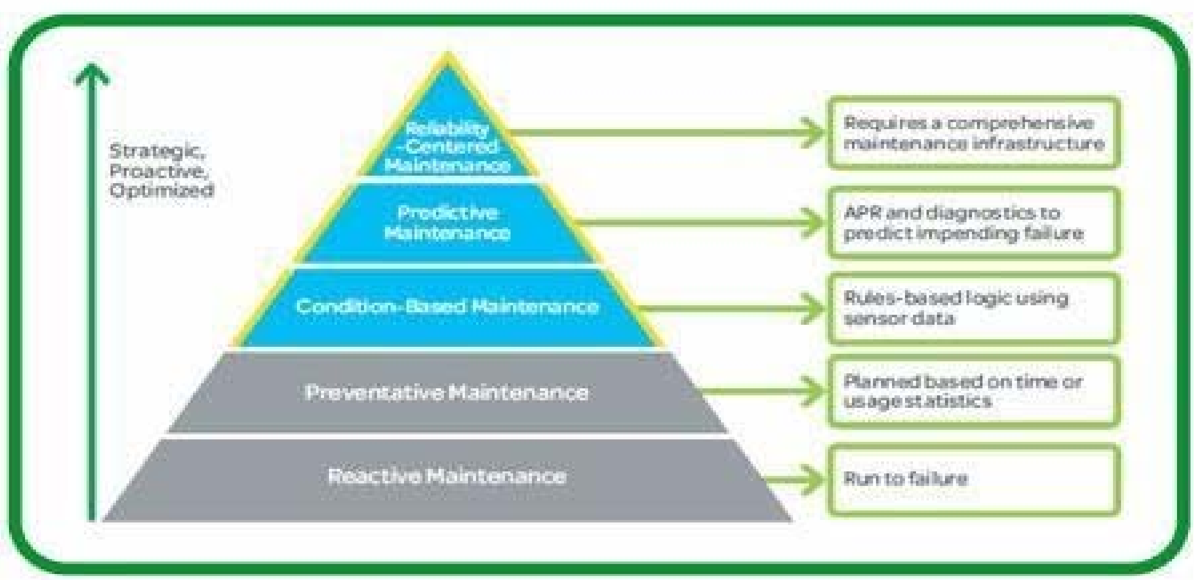




Asset Management

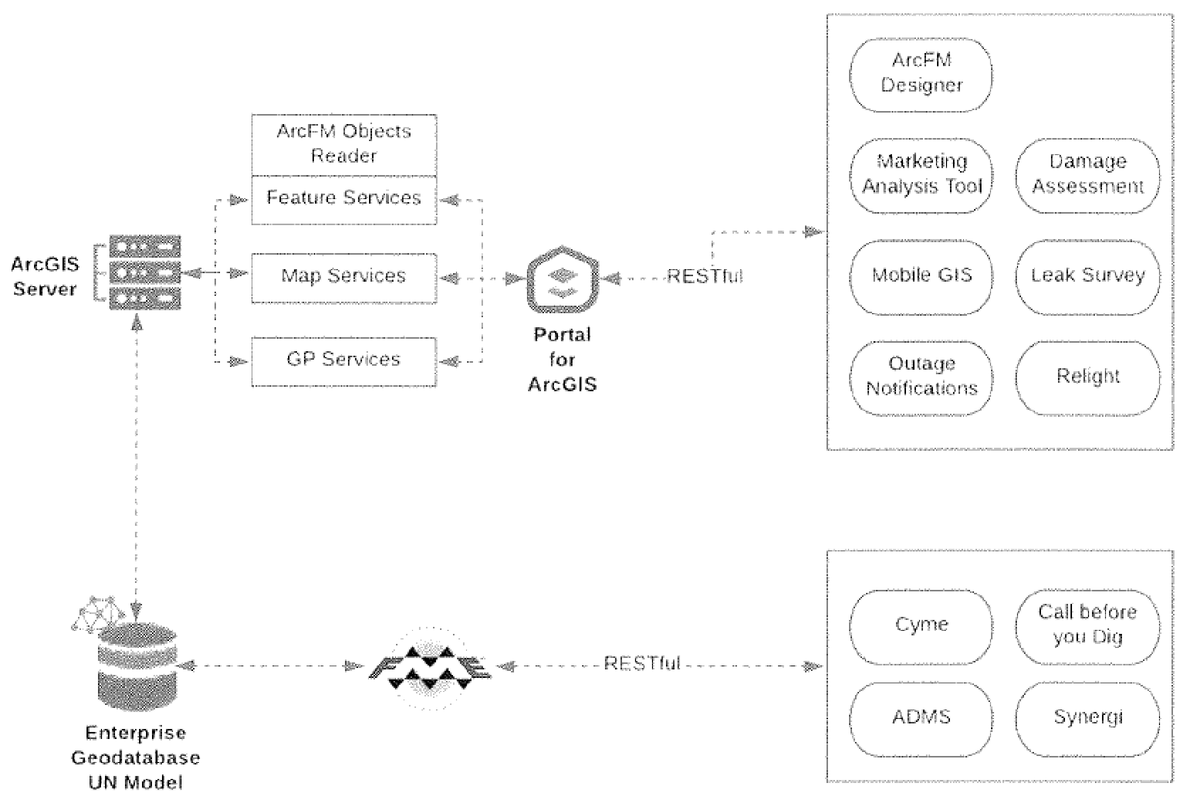
Grid modernization involving automation schemes enable an increase in asset effectiveness by consolidating multiple work and asset management solutions into a single platform and database. These approaches allow for distribution resources to be assessed on a real-time basis to enhance utilization and productivity.

Utilities frequently struggle with balancing the need to invest in modern equipment and infrastructure with demands to minimize costs for customers. One of the most effective ways to avoid substantial rate increases is to maximize the lifetime value of every existing asset. Automated asset management tools enable utilities to blend forecasting and business intelligence with traditional enterprise asset management capabilities. See the illustration below on the improvements in Asset Management as these technologies are implemented.

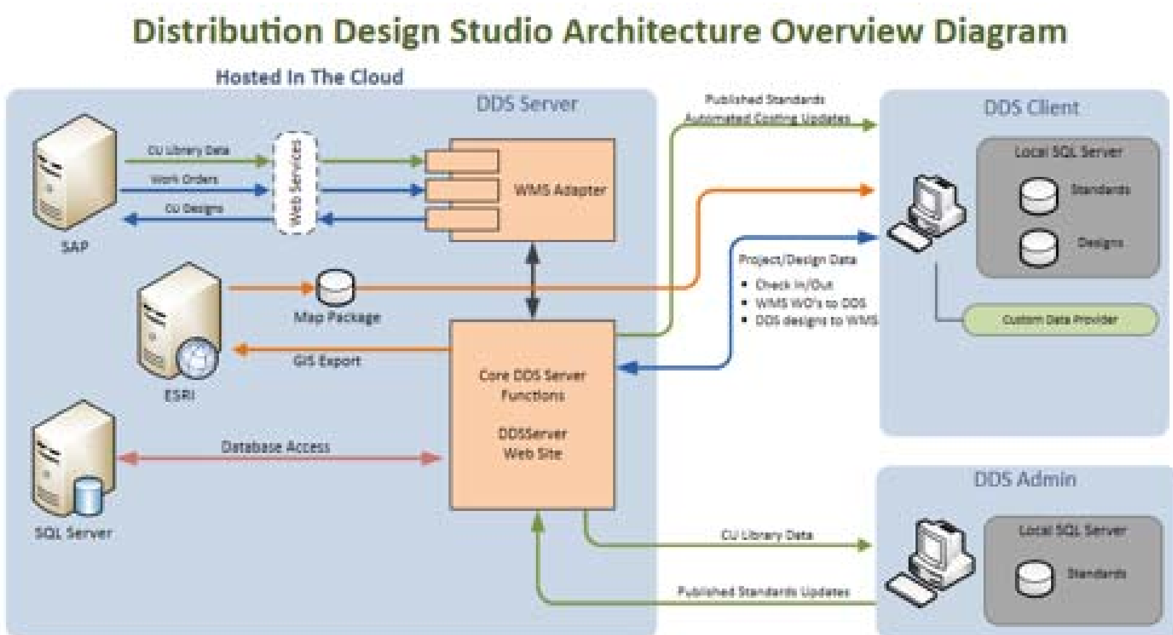


A key component to the Asset Management program is a common and accurate GIS to know where electric utility components are located in a digitized "map" across the Liberty network, and to accurately determine the attributes of such components. The common GIS software is the master repository for locational data and connectivity information, containing asset information describing the physical attributes of the components that make up the Liberty distribution network. This system is used by operations staff to locate and identify assets, increasing worker safety and efficiency. The GIS system is also used as a master repository to supply other integrated applications such as modeling software.

This system is used by the ADMS to greatly increase operational real-time visibility needed as more distributed energy resources are connected to the distribution system and to perform fault location, automatic restoration, and voltage conservation. Liberty is currently in the process of integrating ArcGIS Desktop applications for its distribution network as an early part of its grid modernization strategy to improve customer service reliability, resilience, efficiency and costs. See the below illustration on the architectural and integration overview of the GIS system:

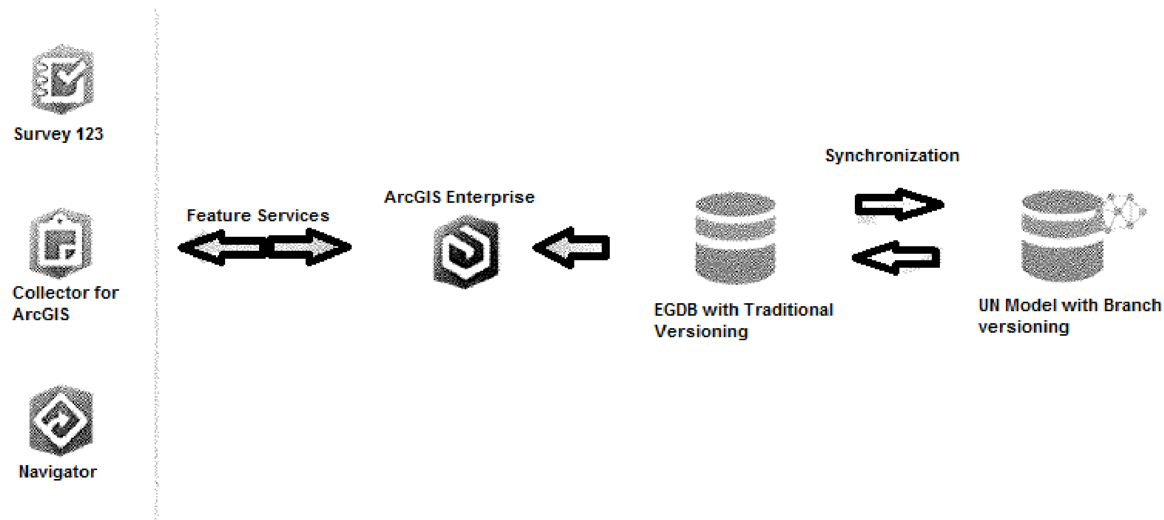


The design estimation tool, Distribution Design Studio ("DDS"), in the GIS will allow engineers and planners to efficiently and effectively design and estimate construction projects, including customer cost estimates for utility projects. See the below illustration on the architectural and integration overview of the DDS system.



Liberty will also implement a relay management tool to facilitate the management of relay settings, maintenance of substations, collection of data, reports and analysis of equipment condition.

In addition, Liberty will continue to implement remote applications for its field workers for the collection of inspection results, including vegetation management and damage assessing. Currently, the location of vegetation related interruptions are being tracked and the inspection activities for reclosers and capacitors are being managed using ArcGIS Online tools and Terra Spectrum application. The Company expects to leverage ArcGIS Desktop and the Terra Spectrum applications to increase the use of remote applications for maintenance activities, assignment of work, and outage management activities. The use of remote applications by field workers will allow the Company to better track, document, and analyze the actual locations and causes of problems. This will better inform other initiatives for reliability and resiliency improvement. See the below illustration of the mobile application design for Liberty.

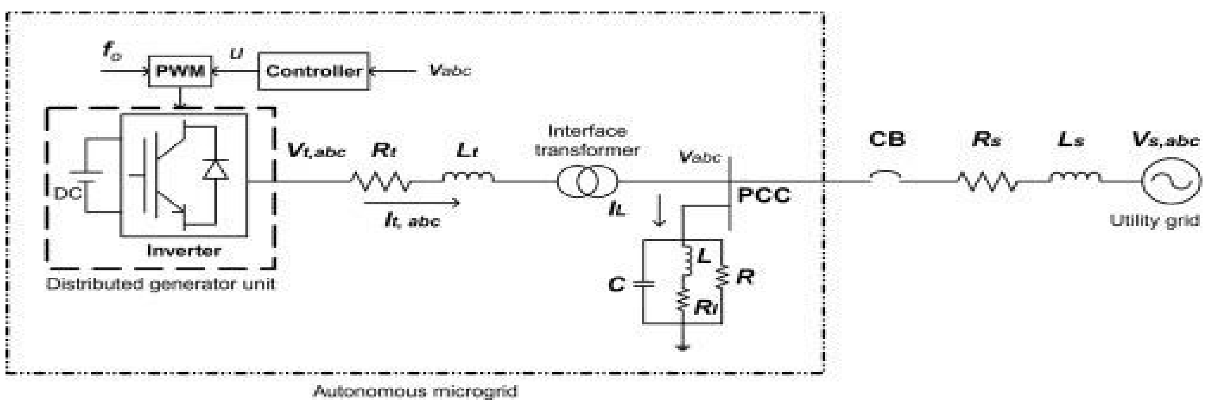


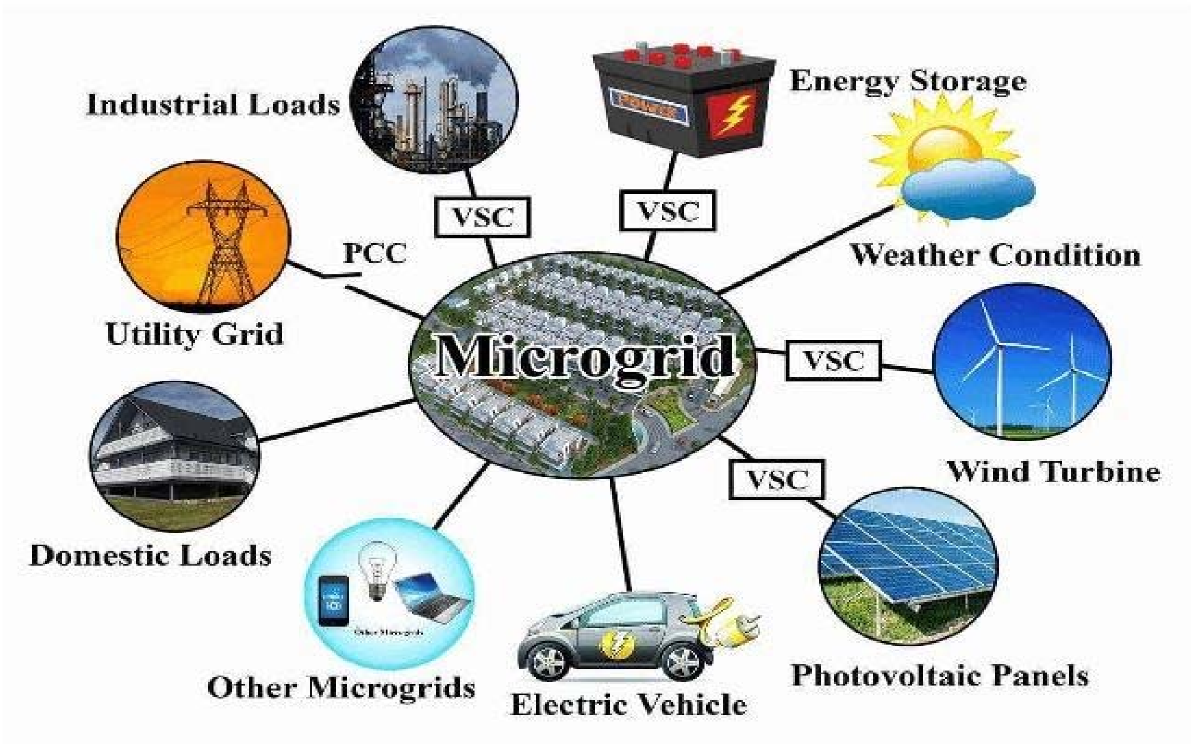
Another part of the recommended asset management system would involve automated systems to ensure power quality analysis on a dynamic basis. Power quality analyzers are the most commonly used tools to observe real-time readings and to collect data for downloading to computers for analysis. While historically handheld analyzers have been used to support isolated troubleshooting functions, a real-time dynamic program would feature systems and devices permanently installed in the distribution system.

Islanding

Islanding is the condition in which a distributed generator ("DG") continues to power a location even though electrical grid power is no longer present. Strict frequency control is needed to balance between load and generation in the islanded circuit to avoid violations from abnormal frequencies and voltages.

Islanded systems enhance the potential of DG to provide power to a portion of the grid absent electric flow from the central generation source. Microgrid designs enable the development of controlled systems that enhance the delivery of distributed resources and can lead to greater efficiencies across the distribution network by localizing generation closer to the site of usage.



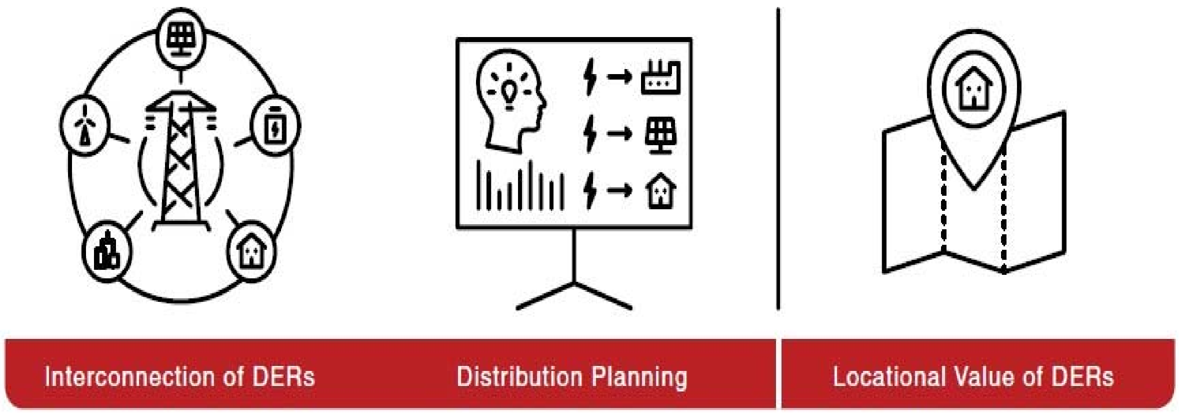


Distributed Energy Resources

There are multiple technologies that enable distributed generation and energy storage applications. Implementing distributed resources offers the opportunity to reduce the energy lost in transmitting electricity because the electricity is generated and delivered close to consumption, perhaps even in the same building. This also improves the management of energy flow on power lines, which could reduce the size and number of power lines that need to be constructed in the future. The graphic below details some of the potential options to generate value:

Application	Description
Generation Deferral	Reduce system peak in order to reduce investments in generation
Wholesale Marketing Resource Call	Reduce system peak in order to provide flexibility in generation requirements during summer peak
Frequency Regulation	Power sources online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements
Synchronized Reserves	Power sources that can increase output immediately in response to a major generator or transmission outage
Supplemental Reserves	Commitments that can be immediately decreased in response to a major generator or transmission outage
Renewables Integration	Engaging in (a) smoothing, (b) shifting, and (c) shaping renewable energy sources
Energy Arbitrage	Opportunity to purchase energy at off-peak rates and sell at higher peak rates
Blackstart	Process of restoring a power station to operation without relying on the external electric power transmission network
Transmission Deferral	Reduce system peak in order to reduce investments in transmission
Voltage Support	The injection or absorption of reactive power to maintain transmission system voltages within required ranges
Distribution Deferral	Reduce system peak in order to reduce investments in distribution
Outage Mitigation	Distributed storage capability to bridge gap in power delivery in event of outage
Power Quality	Maintaining electric power that drives an electrical load and the load's ability to function properly with that electric power
Distribution Loss Reduction	Dispersed functions allow existing generation to function more efficiently and improve the overall efficiency of the electric system

One of the considerations for a DER program involves Hosting Capacity Analysis (HCA). The term “hosting capacity” refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability, or other operational criteria, and without requiring significant infrastructure upgrades. HCAs allow utilities, regulators, and electric customers to make more efficient and cost-effective choices about deploying DER on the grid. If adopted with intention, HCA also functions as a bridge to span information gaps between developers, customers, and utilities, thus enabling more productive grid interactions and more economical grid solutions.



The initial purpose of HCA was to make DER interconnections faster and more efficient. If a utility could know the feeder-level DER penetrations throughout its distribution system, it could more expeditiously approve an application for a new DER installation. Alternatively, it could inform the applicant a distribution system infrastructure upgrade is needed to accommodate new DER or locations on the electrical grid with existing/future grid needs. By accommodating HCA on its system, Liberty will be able to more efficiently plan for integration of distributed energy resources.

The Company is in the process of developing an HCA map, process, and criteria to better inform the decision making for prospective DG installers in our service territory. The hosting capacity will depend on the feeder, existing DG deployed, and criteria that will be rooted in thresholds for voltage, protection, and thermal capability. Using the modeling software tool, solar generation can be added in increments to segments in the feeder until a criteria threshold is reached.

Pending final design of the application, the following information will be provided in the HCA map:

- Substation Name, Feeder, Nominal Voltage, Substation Transformer nameplate MVA;
- Maximum Hosting Capacity or Maximum amount of DER that can be accommodated at one point on the feeder;
- Minimum Hosting Capacity or Minimum amount of DER that can be interconnected anywhere on the feeder;
- Circuit Peak Load, Circuit Min Load, and Daytime Min Load for the previous year;
- Aggregate DG (kW) on feeder, Aggregate DG (kW) Proposed on feeder;
- Latest Revision date; and
- Distance to Source.

The Company has participated in the Locational Value of DG study that was initiated by the Commission and conducted by Navigant Consulting. Liberty will continue to support this effort to better guide the locational benefit of DG on the distribution system.

5.4 Overview of Net Benefits/Costs to Customers

Electric utilities have historically extracted as much value and efficiency as possible with manual controls. Today, however, we see a major shift in the thinking within the electric utility industry as it approaches the issue of building the electric infrastructure to ensure reliable and cost effective electric service given a set of challenges all occurring at the same time:

- A large percentage of skilled labor within the electric utility industry is expected to retire within the next five years, placing stresses on electric utilities to effectively manage systems with a large degree of manual intervention required.
- The Department of Energy (DOE) and industry experts have estimated that losses to the economy due to outages, quality disturbances, and other events total in the billions of dollars annually.
- Challenging financial times are calling into question how electric utilities can continue to access the capital needed to keep pace with projected load growth given the constraints of today's legacy electric grid.
- Under pressure from environmental groups and governments, federal and state regulators are assigning increasingly stringent emissions regulations – resulting in increasing challenges for generators and wires companies to deliver reliable power to customers.
- Increasing levels of intermittent renewable energy along all levels of the grid and less predictable electric vehicle charging at the edge of the grid are placing new challenges not faced before by electric distribution utilities.

This set of issues – all occurring at the same time – presents a form of "perfect storm" that challenges the electric utility industry to identify the optimal approach for delivering cost effective and reliable electricity to customers in the 21st century. The Grid Modernization effort – a way of adding intelligence and new protocols to the electric grid – is seen by many as the way to attack the challenges within the industry.

Liberty has evaluated the economic benefits and costs of available new technologies and has narrowed its implementation to the following new technologies as part of its overall Grid Modernization Program, contained in Appendix E.

Program Comparison - Ranked

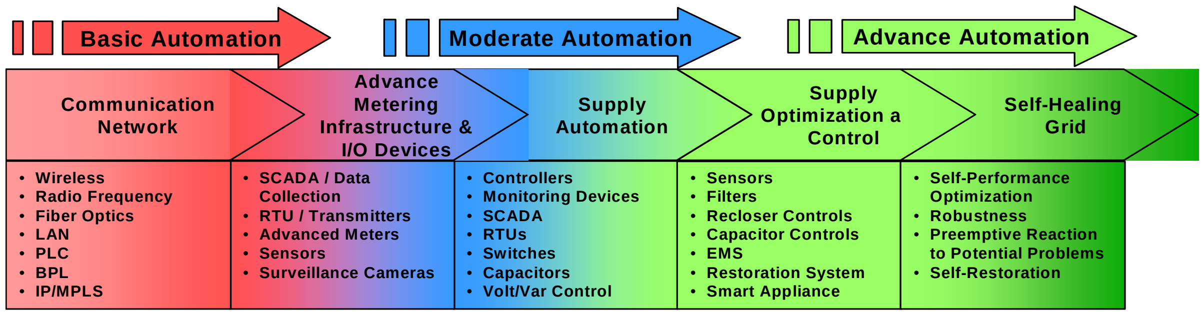
	PV - Benefits	PV - CapEx	PV - OpEx	Terminal Value	NPV	Rank
Conservation Voltage	$ 8,302,813	$ 1,792,831	$ 119,357	$ 7,453,481	$ 13,844,106	1
Asset Management	$ 3,825,127	$ 500,740	$ 119,357	$ 3,388,384	$ 6,593,413	2
Load Forecasting	$ 2,672,409	$ 686,544	$ 214,843	$ 2,292,358	$ 4,063,379	3
Connect/Disconnect	$ 1,743,802	$ 873,362	$ 23,871	$ 1,568,024	$ 2,414,593	4
Islanding	$ 5,793,103	$ 8,442,949	$ 167,100	$ 5,149,434	$ 2,332,488	5
LED Lighting	$ 1,514,155	$ 1,799,658	$ 286,458	$ 1,200,848	$ 628,888	6
Distributed Energy Resources	$ 2,977,231	$ 4,463,750	$ 477,429	$ 2,409,871	$ 445,922	7
Fault Detection	$ 1,760,399	$ 2,991,099	$ 124,132	$ 1,531,260	$ 176,429	8
Energy Management	$ 2,776,319	$ 5,441,529	$ 119,357	$ 2,444,279	$ (340,288)	9
AMI	$ 3,005,607	$ 11,197,510	$ 410,589	$ 1,849,711	$ (6,752,781)	10
Total	$ 34,370,966	$ 38,189,973	$ 2,062,494	$ 29,287,650	$ 23,406,149	

As this economic assessment shows, the total net present value ("NPV") of the Grid Modernization program greatly exceeds the expected implementation cost, thereby providing lower costs to customers over this ten year period.

At the heart of this initiative is the addition of ADMS/AMI systems across Liberty's 45,000 meter system over a five-year period, to serve as the platform that will enable the use of many new technologies and strategies that will improve reliability, resilience, safety, and efficiency of its distribution systems and provide substantial benefits for its customers.

5.5 Overall Program Planning and Implementation

The recommended approach for developing a suitable implementation plan is based on the concept of developing core elements that support initial programs while also establishing foundational elements for future aspects of the grid modernization plan. Below is a conceptual approach:



As illustrated above, there are five key stages to the deployment:

- Stage 1 – The establishment of a communications network to provide a robust backbone for all grid modernization elements.
- Stage 2 – Installation of an AMI network, which is seen as a key foundational element of the overall design. While AMI will provide demonstrable benefits by itself, it also provides the needed infrastructure for such programs as conservation voltage, fault detection, and load forecasting.
- Stage 3 – Supply automation programs (ADMS) provide for the realization of benefits from those use cases that demonstrate the most viable business cases.
- Stage 4 – Supply optimization and control programs will enable Liberty to capture further benefits by enhancing distribution operations on a dynamic basis.
- Stage 5 – The ultimate goal is to utilize the grid modernization effort to explore ways to enhance distribution operations with future programs that will be developed over time.

5.6 <u>Short-Term Plan</u>

With the exception of the Automated Metering Infrastructure implementation, Liberty is proposing a set of "pilot projects" to evaluate the approach for implementation. These pilot projects will assess the business case coupled with the state of technology development leads to the development of a recommended migration strategy. Please see the Grid Modernization Report in Appendix E for the details concerning implementation of the pilot projects.

The first five years of the proposed program implementation covers the years 2021–2025. The following steps are planned during this time:

- ADMS – deployment of the ADMS software, including incorporation of distribution assets in a common GIS database, will provide the software platform for integrating distribution assets and new smart devices into its system.
- AMI – The deployment of the entire AMI system, including all meters, software, Meter Data Management System (MDMS), communications network, repeaters, and field collection devices. The forecast calls for a complete system installation within five years.
- Connect/Disconnect – All disconnect devices will be installed with the AMI meters under glass and will be deployed within the same timeframe as the AMI network.
- Fault Detection – The core elements of the fault detection system will be deployed, allowing for full capabilities of an outage management system. It is anticipated that the fault detection system will leverage data from the metering system to identify locations of outages.
- Conservation Voltage – The goal is to deploy the conservation voltage system very quickly. In the short term, bellwether meters will be used to report on voltage levels across distribution feeders to ensure compliance with ANSI standards. As the AMI system is deployed across the entire service territory, these bellwether meters will be displaced by AMI meters.
- Load Forecasting – The backend systems supporting the load forecasting system will be deployed initially. AMI meters and distribution assets deployed in the field will be utilized to report on load conditions on a real time basis as they are deployed.

- Asset Management – The backend systems supporting the asset management system will be deployed within the first years of the project. AMI meters and distribution assets deployed in the field will be integrated into the system as they are deployed.

- Islanding – The goal in the first phase will be to undertake a pilot and deploy enough islanded resources in order to defer a capital project currently under budget between fiscal years 2023 and 2025. The Company will also consider pilot opportunities to test viability of integrating customer-owned DG resources, test capabilities of energy storage system, and assess electrical and operational efficiency rates.

- Energy Management – Liberty proposes to monitor system development and continue to evaluate the viability of deployment. Within the first five years, Liberty plans to implement an initial pilot to further test the viability of a dedicated program.

- Distributed Energy Resources – Liberty is seeking to have a total of 3% of system peak under management of a dedicated DER program by the end of 2024.

5.7 Long-Term Plan

During the first five year of the program, Liberty will monitor results of each program under management and make adjustments as needed based on actual findings. The current plan for the subsequent five years, covering the years 2025–2029, would include the following:

- Advanced Metering – Continue deploying AMI meters in areas of growth within the service territory. In addition, Liberty will also seek to capture maximum value from the AMI system by looking to optimize the data mapping to ensure that departments can access information in the optimal methodology while also redesigning internal workflows to ensure that work processes are aligned with the new system.

- Connect/Disconnect – Alongside the AMI system, Liberty will seek to learn from the initial stage of the connect/disconnect program to evaluate how to optimize operations.

- Fault Detection – Liberty will seek to expand the outage management system by incorporating elements of isolation recovery to the fault detection system, enabling automated switching of circuits during major outage events.

- Conservation Voltage – The goal of the long-term conservation voltage program will be to optimize operations by testing and implementing automated voltage management systems.
- Load Forecasting – Liberty will identify and implement advanced systems to utilize meter and distribution automation data in load forecasting.
- Asset Management – Liberty will identify and implement advanced systems to utilize meter and distribution automation data in asset management.
- Islanding – The goal in the second phase will be to deploy enough islanded resources to defer three to four capital projects by one or more years.
- Energy Management – Liberty plans to implement an initial deployment involving customers with a mix of smart thermostats and energy management systems.
- Distributed Energy Resources – Liberty is seeking to have a total of 6% of system peak under management of a dedicated DER program by the end of 2029.
- Smart City – The goal is to ensure the installation of LED lights for additional cities within the service territory.

6. ENERGY EFFICIENCY & DEMAND SIDE MANAGEMENTt

6.1 Purpose

The purpose of this section is to: (1) provide an overview of Liberty's energy efficiency and demand side management programs, (2) present an assessment of these programs' impact on energy savings, environmental and health benefits, and (3) discuss at a high-level the programs proposed as part of the 2021–2023 New Hampshire Statewide Energy Efficiency Plan and the Energy Efficiency Resource Standard ("EERS") in Docket No. DE 20-092 and some notable new initiatives.

6.2 NHSaves Energy Efficiency Programs

Overview

Energy efficiency is a priority for Liberty and is a key strategy for building a modern and sustainable energy future. Energy efficiency is emission free and the lowest-cost resource available to utilities, customers, and states. Every kilowatt-hour ("kWh") saved through energy efficiency helps Liberty achieve deeper energy savings, reduce harmful greenhouse gas ("GHG") emissions, save customers money, and mitigate the need for additional power generation.

Liberty has a long history of offering energy efficiency programs and services to its customers, dating as far back as 1987. Since 2002, Liberty has partnered with the New Hampshire electric and natural gas utilities ("NH Utilities") to administer a consistent portfolio of energy efficiency and demand response programs to residential, commercial and industrial ("C&I"), and municipal customers across the state, currently marketed under the statewide brand "NHSaves." Through this utility collaboration, Liberty and the NH Utilities deliver innovative, award-winning programs that are designed to provide flexible, cost-effective solutions to all possible customer segments, such as helping residential customers and homeowners to install more efficient lighting, appliance and HVAC measures; helping small, mid-size and large businesses install high efficiency motors, processing and control systems; and helping municipal and school districts install more efficient HVAC, and indoor/outdoor lighting and control systems.

The energy efficiency programs offered by Liberty and the NH Utilities provide significant value to all customers, both participants and non-participants and help support the state's economy in multiple ways. Specifically, delivering cost-effective energy efficiency programs to customers helps lower energy bills, generates local jobs, reduces the energy dollars that go toward out-of-state energy generation, and increases the quality of the state's building stock. Businesses can invest energy savings toward making their companies more profitable, and into operations and personnel. Towns and cities can use taxpayers' dollars to fund critical infrastructure projects and public services. Homeowners, particularly limited-income customers, can use their energy savings toward their most critical needs, with their dollars staying in the local economy. A variety of other non-energy benefits are created as well, including:

- Lower asthma rates and other health-related improvements due to better indoor and outdoor air quality.
- Improved business performance and productivity due to the installation of high-efficiency equipment, such as lighting controls and commercial kitchen equipment.
- Reduced maintenance costs.
- Improved building value.
- Increased comfort which can improve occupant performance, whether that be students in school or office building workers.
- Improved safety.

Impact of the NHSaves Programs on Energy Consumption

Since 2002, the energy efficiency programs Liberty has implemented have saved customers over 1.3 million electric kilowatt-hours over the life of the energy efficiency measures installed, and over 1,000 kW in annualized peak capacity reduction, which translates into customer savings of over $140 million. Liberty's programs have also served over 14,500 participants per year on average during that time span. Table 6.1 summarizes Liberty's annual and lifetime megawatt hour savings, customer participation, program costs, and benefits from 2002 through 2019.

Also, since 2012, Liberty has measured customer awareness of its energy efficiency programs. During this period, customer awareness of the programs has nearly doubled, increasing from 30% in 2012 to 58% in 2019[28].

28 Luth Research (2019, December). Liberty Utilities – Customer Satisfaction Tracking New Hampshire Electric. Q. "Are you aware that Liberty Utilities offers energy efficiency programs to help you reduce your energy costs?"

Table 6.1. NHSaves Program Results – Liberty Utilities, 2002–2019

Year	Annual MWh Savings	Lifetime MWh Savings	EE Measures/ Participants	Expenses (000's)	Benefits (000's)
2002	5,035	64,825	4,648	$1,190	$4,554
2003	4,990	74,322	8,338	$1,252	$6,053
2004	4,019	61,104	6,733	$1,148	$5,122
2005	3,559	53,821	4,584	$1,298	$4,343
2006	4,001	56,958	4,441	$1,599	$5,726
2007	2,962	34,884	5,281	$1,311	$3,904
2008	6,120	74,641	22,649	$1,379	$7,894
2009	5,395	66,942	14,147	$1,673	$8,077
2010	5,848	72,485	17,550	$1,407	$8,847
2011	5,361	64,788	19,504	$1,458	$6,481
2012	5,644	74,465	7,595	$1,473	$6,245
2013	5,591	73,283	20,669	$1,417	$8,181
2014	5,347	71,943	18,476	$2,145	$9,285
2015	9,265	125,431	23,463	$2,789	$11,361
2016	7,308	110,029	9,318	$1,960	$11,183
2017	6,299	83,062	12,608	$2,157	$9,166
2018	7,545	91,009	21,428	$2,577	$10,016
2019	10,179	116,700	29,868	$3,721	$13,836
Total	**104,468**	**1,370,692**	**251,300**	**$31,954**	**$140,274**

Table 6.2 details Liberty's annual and lifetime kilowatt-hour savings, customer participation, program cost, and benefits, by customer program and sector, for its most recently completed program year of 2019. Based on these results, Liberty's average cost of 2019 savings was

3.36 cents[29] per lifetime kilowatt-hour, as compared to the current average retail price per kilowatt-hour of 16.34 cents, as of December 9, 2020.[30] This represents a simple net benefit ratio on program investments of 4.87 to 1.

Table 6.2. Liberty Programs' Results — 2019

Sector/Program	Annual kWh Savings	Lifetime kWh Savings	EE Measures / Participants	Expenditures	Benefits
Residential					
ENERGY STAR Homes	130,469	2,908,931	40	$167,964	$1,837,722
ENERGY STAR Products	1,312,687	8,776,072	19,138	$318,447	$988,215
Home Energy Assistance	198,796	2,722,154	168	$670,522	$610,449
Home Energy Reports	1,210,000	3,509,000	10,289	$130,924	$282,239
Home Performance w/ENERGY STAR	105,608	1,876,918	62	$314,424	$1,098,773
Residential Total	**2,957,560**	**19,793,075**	**29,698**	**$1,602,281**	**$4,817,397**
Commercial & Industrial					
Large Business	4,337,869	57,940,088	33	$968,272	$5,237,713
Municipal	541,529	7,551,764	19	$166,842	$708,441
Small Business	2,342,105	31,415,220	118	$886,127	$3,072,876
C&I Education	-	-	-	$54,316	-
C&I Total	**7,221,503**	**96,907,071**	**170**	**$2,075,557**	**$9,019,029**
Forward Capacity Market	-	-	-	$43,182	-
Overall Total	**10,179,064**	**116,700,147**	**29,868**	**3,721,019**	**$13,836,427**

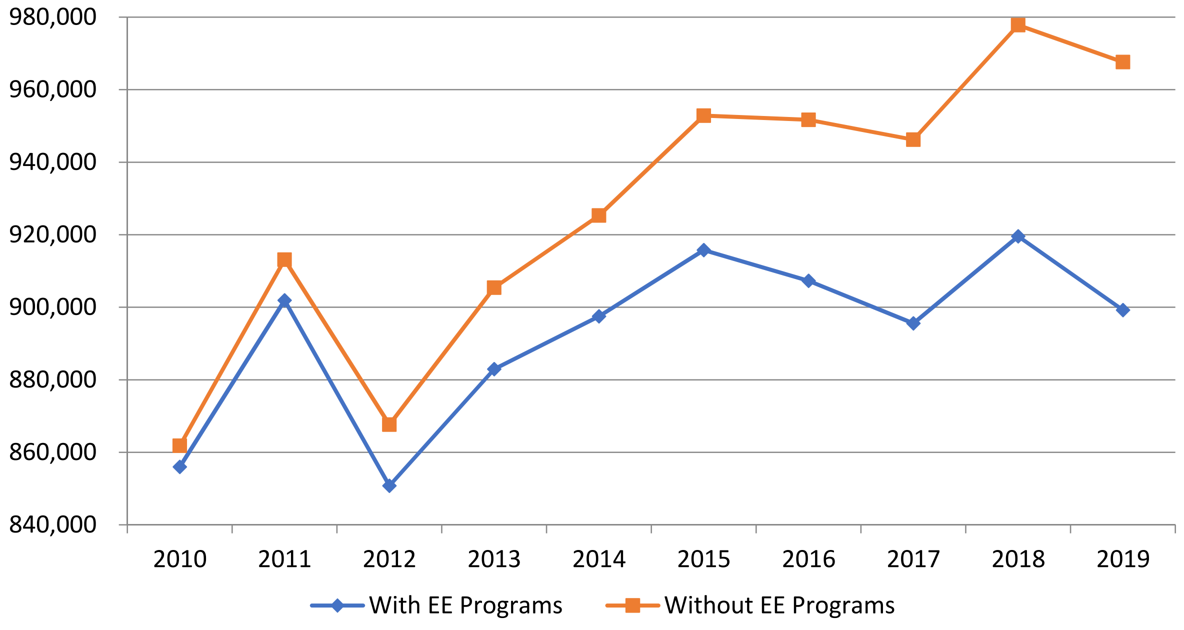
The 2019 annual kilowatt-hour savings are approximately 1.13% of Liberty's total billed delivery kilowatt-hour sales in 2019 (10,179,064 / 899,231,963). The average life of the installed energy efficiency measures is 11.46 years. As a result, the savings associated with

29 Value calculated by dividing the total program costs and utility performance incentive ($2,167,9313,721,019 + $196,915000) by Lifetime kWh savings achieved (71,943,030116,700,147).

30 New Hampshire Office of Energy and Planning Strategic Initiatives (December 14, 2020). Average Fuel Prices in New Hampshire – Electricity. Retrieved from http://www.nh.gov/oep/energy/energy-nh/fuel-prices/index htm#note_2 https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm

the measures installed in 2019 will continue well into the future and the cumulative impact of the programs will become more significant over time. As illustrated in Figure 6.1, the cumulative impact of the NHSaves Programs over the past ten years has resulted in a decline of delivered MWh sales of 7.6% in 2019.

Figure 6.1. Cumulative Impct of Energy Efficiency Program Savings on Annual MWH Sales



Impact of the Energy Efficiency Programs on Capacity or Peak Reduction

In addition to the kilowatt-hour energy savings, the Liberty energy efficiency programs also provide capacity or peak demand reductions. Table 6.3 summarizes the average annual capacity reduction coincident with the New England peak resulting from the programs efficiency measures installed by customers between January 1, 2010, and December 31, 2019. As shown, the energy efficiency programs implemented by Liberty reduced New

England's peak load (which currently occurs in the summer) by 1,113 kW, which is approximately 0.54% of Liberty's system peak load[31] in New Hampshire.

Table 6.3. NHSaves Programs Capacity Reduction Based on Operable Measures Installed Between January 1, 2010, and December 31, 2019

Year	Coincident with ISO-NE Peak		
	Residential	**C&I**	**Total**
2010	117	898	1,015
2011	84	762	846
2012	94	844	938
2013	173	635	808
2014	192	855	1,047
2015	918	476	1,394
2016	459	1,032	1,491
2017	382	528	910
2018	341	627	969
2019	465	1,249	1,714
Total	**3,226**	**7,906**	**11,132**
Average kW/mo (120 months in period)	**26.88**	**65.89**	**92.77**
Annualized Capacity Reduction	**323**	**791**	**1,113**

The New Hampshire electric utilities, including Liberty, are the only energy efficiency providers in New Hampshire participating in the ISO-NE's forward capacity market. The proceeds obtained through participation in this market have totaled $3,010,787 from 2010 through 2019. These proceeds are utilized as a funding source for the NHSaves Programs, and the amount obtained in 2019 represented approximately 19.8%[32] of Liberty's NHSaves Program expenditures in 2019. In order to qualify for payments from the ISO-NE, Liberty

31 Granite State Electric's Peak Load was 205,942 kW on June 22, 2011.
32 ISO-NE FCM Proceeds in 2019 were $738,156 as compared to Total Energy Efficiency program expenditures of $3,721,019 in 2019.

must certify to the ISO-NE's satisfaction that the capacity reductions are operational during hours of peak electrical usage. Liberty has developed the necessary reporting, measurement, and verification plans needed to evaluate the impact of the efficiency measures at the time of the New England peak and the resulting capacity reduction load value that qualifies for payment from the ISO-NE. Liberty has met the rigorous reporting standards and requirements to participate in the forward capacity market. As a result, the estimated capacity reductions summarized above are an accurate representation of the capacity reductions resulting from the NHSaves Programs as they have been thoroughly reviewed by ISO-NE and independently certified.

State Energy Policy - Energy Efficiency Resource Standard (EERS)

In August 2014, the New Hampshire Public Utilities Commission (PUC) initiated an informal, non-adjudicative stakeholder process to develop a framework, the EERS, within which the NHSaves Programs would be implemented. The process resulted in an eighteen-month dialogue among the Commission, the NH Utilities, and numerous stakeholders. In 2016, the state's first EERS was established through a settlement agreement filed with the Commission.[33] The EERS is the framework within which the NHSaves Programs have been implemented since 2018, and requires the NH Utilities to file triennial plans, to pursue annual savings goals, and to achieve the long-term objective of achieving all cost-effective energy efficiency.

33 State of New Hampshire Public Utilities Commission. DE 15-137. *Order No. 25,392: Energy Efficiency Resource Standard*, Aug. 2, 2016. Available at: https://www.puc.nh.gov/Regulatory/Orders/2016orders/25932e.pdf.

Coincident with the EERS, the Commission also established a recovery mechanism to compensate the NH Utilities for lost revenue resulting from the implementation of NHSaves Programs under the EERS. The NH Utilities file annual updates with the Commission regarding any necessary changes that need to be made to the Systems Benefit Charge ("SBC") or Local Delivery Adjustment Clause ("LDAC"), the primary funding mechanisms for the NHSaves Programs. The SBC and LDAC are nominal charges on customers' electric and natural gas utility bills, respectively.

During the state's transition to the EERS, the Commission extended for an additional year the approved 2015–2016 NHSaves Programs (i.e., the program implementation and established annual savings targets for the 2017 program year). On January 2, 2018, the Commission approved the implementation of the NH Utilities' first three-year plan ("2018–2020 Plan").[34] The NH Utilities filed plan updates in September 2018 ("2019 Plan Update") and September 2019 ("2020 Plan Update") to realign energy-saving goals and program budgets with the Commission-approved 2018–2020 Plan. The 2021–2023 Plan is the second triennial plan filed by the NH Utilities under the EERS via Docket No. DE 20-092 on September 1, 2020.[35]

34 State of New Hampshire Public Utilities Commission. DE 17-136. *Order No. 26,905: 2018-2020 New Hampshire Statewide Energy Efficiency Plan*, Jan. 2, 2018. Available at: https://www.puc.nh.gov/Regulatory/Orders/2018orders/26095e.pdf.

35 New Hampshire Electric and Natural Gas Utilities (2020, September 1). 2021-2023 New Hampshire Statewide Energy Efficiency Plan. Retrieved from https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092_2020-09-01_NHUTILITIES_EE_PLAN.PDF

6.3 Energy Efficiency Resource Plan (EERS) Plan: 2021–2023

In preparation of the 2021–2023 EERS Plan, Liberty and the NH Utilities reviewed energy efficiency portfolios across North America to determine additional opportunities to modify, improve, and lead the NHSaves Programs toward cost-effective, comprehensive energy savings over the next three years. Liberty and the NH Utilities also engaged in a collaborative stakeholder process to capture feedback from key experts, constituents, trade allies and customers in New Hampshire and that feedback is also reflected in the plan. Market trends, new federal regulations and policies, changing state building codes, emerging technologies, and baseline studies were also incorporated into the NH Utilities' planning process. In addition, the NH Utilities used evaluation results during the 2018–2020 term to help steer the NHSaves Programs toward greater efficacy while driving energy savings, GHG emissions reductions, and increased economic benefits.

Plan Highlights

As part of the 2021–2023 Plan, Liberty and the NH Utilities are focused on increasing the scale of the energy savings and broadening customer participation in the NHSaves Programs. To accomplish this, the 2021–2023 Plan includes the continuation of many of the successfully deployed programs from prior years as well as the introduction of several new offerings, all designed to increase New Hampshire's leadership in energy efficiency and demand management. For example:

- For residential customers, Liberty will introduce or more heavily promote several program pathways, including: code-plus initiatives, online platforms, single-measure rebates, energy kits, and visual audits.

- For C&I customers, Liberty will encourage additional participation through the expansion of the "Main Street" efforts and community outreach initiatives, as well as the creation of standard marketing collateral targeting C&I customers and market segments. Liberty will also continue to market and make available its customer On-Bill Financing program, which has proven to be a key resource for driving customer activity, particularly with municipal and small business customers during the COVID-19 pandemic.

- Liberty and the NH Utilities intend to focus on delivering tailored, comprehensive solutions to customers that will drive electric savings. At a high-level, "tailored, comprehensive solutions" for C&I customers will involve testing various channels, incentive models, and strategies to identify more precisely what motivates customers and contractors to implement comprehensive energy-saving projects.

- Liberty and the NH Utilities will explore offering a tiered incentive design focused on the delivered energy savings of an entire project, rather than the current approach of incentivizing single measures.

- Liberty and the NH Utilities will continue to offer cost-sharing comprehensive audits and determine if this incentivizes more C&I customers to invest in deeper energy-saving projects.

- For residential customers, Liberty and the NH Utilities will promote comprehensiveness through the introduction and heavy promotion of multiple "on ramps" to energy efficiency that will be utilized to encourage investment in multiple-measure projects.

- Liberty and the NH Utilities are deliberately expanding the programs to focus on measures beyond lighting, which have provided an inexpensive and relatively easy means of reducing electricity for many years. Despite the recent federal roll-back of minimum lighting technology efficiency standards, the lighting market has continued to rapidly transform and transition to the widespread adoption of LEDs. In order to help maintain and accelerate the strong demand for high-efficiency ENERGY STAR LED technologies, Liberty and the NH Utilities will continue to aggressively support and incentivize energy-efficient bulbs and fixtures for the NHSaves Residential Programs through the end of 2021. However, beginning in 2022, and depending on how the marketplace responds to the relaxed federal standards, Liberty and the NH Utilities will transition program support to discount retailers focused on reaching the last-to-adopt and hard-to-reach customer segments. Sizeable program potential still remains in capturing retrofit lighting applications for commercial small, large and municipal customers, particularly when coupled with advanced control technologies, and this area will continue to be a focus throughout the next three year term.

- To scale up customer participation and drive deeper energy savings, Liberty and the NH Utilities are making a concerted effort to develop a comprehensive workforce development strategy. The goal here is to expand the universe of potential energy efficiency service providers in the state as well as increase the available talent pool from which the existing service providers in the state can leverage.

Table 6.4 summarizes the NHSaves program offerings scheduled to be available in 2021 with the assumption that the Settlement Agreement in Docket No. DE 20-092 is approved. In the event that the Settlement Agreement is not approved, these tables may be updated during this adjudicative proceeding to provide the approved program offerings.

Table 6.4. NHSaves Program Offerings

Program	Example Measures	Incentives
Residential Sector		
1. ENERGY STAR Products	LED lighting, ENERGY STAR appliances and HVAC measures	Instant discounts via retail, equipment distributor and online marketplace channels
2. Home Performance with ENERGY STAR	Audit, air sealing, weatherization and HVAC measures	75% rebate up to $8,000; 3rd party and On-Bill Financing
3. ENERGY STAR Homes	New construction measures beyond current building code standards	Builder training and verification of code + measure installations
4. Home Energy Assistance	Air sealing, weatherization, appliances, lighting and HVAC measures	Up to $20,000 in services, at no cost, depending on income eligibility.
5. Home Energy Reports	Personalized energy usage reports detailing normative comparisons	No cost service
6. Energy Optimization (Pilot)	Cold-climate Air-Source Heat Pumps (ductless & mini-splits) when displacing existing fossil-based heating source w/Integrated Controls	$1,250 per Ton
Non-Residential Sector		
6. Small Business	Interior and exterior lighting, refrigeration, compressed air, controls, electric hot water heating	Prescriptive & custom incentives up to 75% of project costs; Midstream channels; Technical assistance; Free energy audits; On-bill financing
7. Large Business	Interior and exterior lighting, process manufacturing, custom controls, retro-commissioning, VFDs	Prescriptive & custom incentives up to 50% of project costs; Midstream channels; Technical assistance; On-bill financing
8. Municipal	Interior and exterior lighting, HVAC and thermal savings	Up to 75% of project costs; Midstream prescriptive incentives; Technical assistance; Free energy audits; On-bill financing
9. Load Curtailment	Temporary reduction in facility kW load upon signal, during times of peak electric demand	$ per kW Reduction

Table 6.5 summarizes the specific Liberty energy efficiency program and sector savings targets and budgets for NHSaves program offerings scheduled to be available in 2021 through 2023. Liberty plans to invest over $23 million in energy efficiency programs and services (expressed in 2021 dollars) during the next three year period, as compared to just over $13 million invested during the 2018 through 2020 term, a 80% increase. The Liberty energy efficiency programs are projected to generate 41,172 annual MWhs of customer energy savings, as compared to 29,183 annual MWhs of savings during the 2018 through 2020 term, a 41% increase.

Table 6.5. Liberty 2021–2023 Energy Efficiency Program Portfolio, Key Metrics

Program	Program Benefits ($000)	Utility Costs ($000)[1]	Customer Costs ($000)[1]	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	# Customers Served
Residential Programs								
Energy Star Homes	6,085.8	893.1	112.1	397.2	9,178.7	86.0	6.8	210
Energy Star Products	4,543 9	2,572.0	234.0	4,275.3	37,978.1	789.1	624.5	65,807
Home Energy Assistance	12,236 2	4,788.4	0.1	1,335.8	21,329.4	236.8	145.7	1,020
Home Energy Reports	452.0	378.3	-	3,862.9	3,862.9	833.9	537.9	30,768
Home Performance with Energy Star	3,548.7	1,755.8	345.8	320.6	4,985.3	86.2	61.0	207
Energy Optimization *(Pilot)*	-	130.8	-	-	-	-	-	-
Residential Market Education	-	139.7	-	-	-	-	-	-
Res ISO FCM Expenses	-	116.5	-	-	-	-	-	-
Sub-Total Residential	**26,866.6**	**10,774.6**	**692.1**	**10,191.7**	**77,334.4**	**2,032.0**	**1,375.9**	**98,012**
Commercial, Industrial & Municipal								
Large Business Energy Solutions	17,891.4	6,123.2	6,252.5	16,166.6	200,445.8	1,336.9	1,524.5	788
Load Curtailment	3,538 2	1,199.3	-	-	-	-	-	162
Municipal Energy Solutions	1,005.8	516.2	565.1	1,066.5	12,882.1	97.6	51.2	279
Small Business Energy Solutions	16,947.1	4,959.2	3,680.4	13,747.0	182,808.5	1,882.4	1,603.6	1,077
C&I Market Education	-	135.9	-	-	-	-	-	-
C&I ISO FCM Expenses	-	154.4	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**39,382.5**	**13,088.2**	**10,498.0**	**30,980.0**	**396,136.5**	**3,317.0**	**3,179.3**	**2,306**
Total	**66,249.1**	**23,862.8**	**11,190.0**	**41,171.7**	**473,470.9**	**5,349.0**	**4,555.2**	**100,318**

[1] Utility and Customer Costs Expressed in 2021 Dollars

Complete details of the 2021–2023 EERS program offerings for Liberty and the NH Utilities can be found in the 2021–2023 EERS Plan submitted to the Commission via Docket No. 20-

092.[36] Some notable new program and pilot offerings as part of the plan are detailed in the next section.

New Programs & Pilot Offerings

Load Curtailment Program

Effective demand-reduction strategies can help reduce energy prices and price spikes during summer. For the 2021–2023 term, Liberty intends to deploy an Active Demand Reduction, Load Curtailment program to its Commercial and Industrial customers program to help to flatten peak loads, improve system load factors, and reduce costs for electric customers.

Also referred to as Interruptible Load, the Load Curtailment offering provides an incentive for verifiable shedding of load by customers in response to communication from Liberty or its curtailment service providers ("CSPs"). The program is based upon the design of the Eversource and Unitil Electric pilot programs implemented during the 2018–2020 term. The Load Curtailment offering is technology agnostic, which means that customers are able to use any technology or strategy and earn an incentive based on their summer seasonal average curtailment performance.

With a technology agnostic approach, customers with on-site generation are allowed to participate in the Load Curtailment offering. However, the NH Utilities have established certain criterion in order to not increase emissions, including prohibiting participation by

36 New Hampshire Electric and Natural Gas Utilities (2020, September 1). 2021-2023 New Hampshire Statewide Energy Efficiency Plan. Retrieved from https://www.puc nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092_2020-09-01_NHUTILITIES_EE_PLAN.PDF

"emergency only" back-up generators. Allowed generators in the program must pass local, state, and federal guidelines for participation in demand response programs. These permitting procedures mean this class of generator (typically EPA Tier 4) can operate a higher number of hours per year and produce little emissions, especially when compared to electrical grid emissions during peak hours.

The Load Curtailment offering provides an incentive to C&I customers to temporarily reduce facility load upon a signal from Liberty or its CSP during times of peak electric demand (referred to as "events"). Generally, curtailment events will last three hours and occur during July and August. Typically, there will be between one to eight events per summer season depending upon ISO-NE load conditions.

Liberty, with assistance from its CSPs, will identify customers with curtailable load, assess curtailment opportunities, process and approve customer enrollment applications, manage the relationship with participants, call and manage curtailment events, oversee customer performance, and calculate payments.

Table 6.6 details the projected customer benefits, costs, kW savings, and number of customers served through the program during the 2021–2023 term for Liberty. In summary, over $3.5M in customer benefits will be generated through the program, as compared to costs of just under $1.2M, for a benefit cost ratio of 2.95. Liberty plans to serve 162 participants and generate in average of 5,293 in Summer kW savings per year.

Table 6.6. C&I Load Curtailment Program, 2021–2023: Key Metrics

Year	Benefits ($000)	Costs ($000)	Summer kW Savings	# Participants
2021	$ 726.2	$ 271.6	3,343.2	34
2022	$ 1,112.2	$ 376.9	5,014.8	51
2023	$ 1,699.8	$ 550.8	7,522.2	77
Total	$ 3,538.2	$ 1,199.3	15,880.3	162

Energy Optimization Pilot

Energy Optimization ("EO") is an energy resource framework that seeks to minimize customers' total energy usage across all energy sources while maximizing customers' benefits. In particular, EO often focuses on conversions from delivered fossil-fuel heating systems to higher efficiency electric systems. EO strategies account for both equipment efficiency, as well as the mix of fuels used, which distinguishes it from fuel switching and beneficial electrification, which focus primarily on fuel type but do not necessarily prioritize overall energy efficiency.

Beginning in 2021, Liberty and the NH Utilities plan to implement an EO pilot based on the New Hampshire Electric CoOp (NHEC) Social Responsibility Heat Pump program as well as offerings in other New England states. The EO pilot will focus on displacing residential delivered fossil fuel through the adoption of cold climate air source heat pumps ("ASHPs"), including central and mini-split systems. The pilot will provide Liberty and the NH Utilities with a more comprehensive understanding and experience of the benefits of heat pumps to the electric system, as well as the impact on emissions from GHGs and nitrogen and sulfur oxides. Liberty and the NH Utilities will also investigate customer experience and optimal program delivery standards related to this offering.

To be eligible for the EO pilot, customers must be willing and able to displace their existing heat source for at least one heating zone(s) of their home for a substantial portion of the heating season (see requirements below regarding switchover set points). For the EO pilot, Liberty and the NH Utilities will recommend, but not require, that the home be weatherized in advance of participation to ensure optimal sizing of the ASHP. Liberty and the NH Utilities will also recommend that customers maintain a backup automatic feed heating system. In these cases, customers must allow for the installation of integrated controls that will automatically assign the most efficient heating system to operate during the heating season, based on the outdoor temperature. Homes in which a backup heating system is deemed unnecessary will not be required to have integrated controls. Since the vast majority of the installations in the pilot are projected to have a backup system, the narrative focuses on these installations.

Existing Heat Pump Program

For more than a decade, Liberty and the NH Utilities have provided incentives for the installation of high-efficiency ASHPs and have adopted best practices when cold climate heat pumps became commercially available. To date, heat pump units have typically been treated as a “lost opportunity” in which it was assumed that the customer was making a choice between the program-incented high-efficiency unit and a less expensive, standard-efficiency unit. The kWh and kW savings were therefore calculated based on a comparison between the high-efficiency and standard-efficiency unit and assumed both heating and cooling savings.

Pilot Purpose

The EO pilot is designed to gather information on both program design elements and key regulatory questions, including how Liberty and the NH Utilities should account for fossil fuel and electricity savings (positive and negative). The EO pilot will be accompanied by an impact and process evaluation to guide future program design should Liberty and the NH Utilities recommend that the pilot expand to a full-scale program. The impact and process evaluation will also assess issues raised by the Commission in Order No. 26,322, as described in Section 7.6.

Target Population

The pilot has a goal of 100 participants per year across all utilities over the 2021–2023 term, of which Liberty would have an annual goal of nine participants. The pilot will target homes with existing HVAC configurations that are well-suited for ASHP conversions, but where the homeowners are not already planning to install ASHPs for heating (which are already incented by the existing ES Products program). The pilot will target customers heating with oil and propane furnaces and boilers. The target population will include:

- Customers who are not actively considering heat pumps but who have central A/C systems, that are failing or old;
- Customers who are not actively considering heat pumps but who use window A/C units;

- Customers who are actively considering the installation of a central A/C system and who currently have window A/C units or no cooling system; and
- Customers who are currently interested in heat pumps only for cooling, but not heating.

While not part of the target population, those heating with auto-fed wood pellet stoves and boilers will also be eligible on a limited basis provided they meet other pilot requirements for integrated controls and provision of fuel data.

Customer and Contractor Outreach

The EO pilot will leverage existing pathways for incentivizing high-efficiency heat pump technologies, as well as design new outreach efforts for the target population and technologies. Liberty and the NH Utilities will engage customers through online and in-person education, targeted incentives, marketing, and financing solutions (e.g., on-bill financing and third-party loan programs). Customer education will focus on how to optimize their heating system's efficiency and proper maintenance and upkeep.

A cornerstone of the EO pilot will be a broad promotional outreach effort, including training for HVAC and energy efficiency contractors on the benefits of ASHP technologies, and the need for integrated HVAC controls to optimally operate the ASHP with the building's existing heating system. Customers' existing heating systems will generally be expected to provide backup heating during the heating season's coldest temperatures while the ASHP will meet customers' full heating needs for the rest of the season.

Liberty and the NH Utilities will market the program to the following customers through personal outreach, direct marketing, collaboration with interested stakeholders, and other methods:

- HPwES program customers (past, present, and future);
- Existing customers of HVAC contractors;
- NH Electric Utility net metering Solar PV customers; and
- Customers who have installed battery storage on their own or through the Company's pilot.

Customer Eligibility

Customers may participate in the EO pilot if they meet the following eligibility guidelines:

- Are willing to allow for the installation of integrated controls (not required if a customer removes the existing heat source for a whole zone(s) within the home);
- Are willing to provide data on their delivered fuel consumption, including data from no less than one year prior to the installation of the heat pump. This data will enable evaluation of fossil fuel and electricity usage, both before and after the installation of the heat pump technology. The customer can provide the fossil fuel records directly, or sign a release form that allows evaluators to obtain the data directly from the customer's fuel company;
- Agree to meet a maximum outdoor temperature set point (determined by the Utilities) for the switch over from the backup heating system to ASHPs; and
- Agree to implement a full heating zone(s) displacement. Partial heating zone installations are not eligible.
- Backup heating systems must be automatic feed systems. These include boilers, certain types of stoves, and furnaces.

Incentive Structure

Incentives for EO are designed to move a customer away from their current primary fossil fuel heat source to use high-efficiency ASHPs as their primary heat source instead. This proposition differs from a standard ASHP program offering, which incentivizes a customer who is already purchasing an ASHP to buy a more efficient unit, rather than a typical unit. In the EO framework, the customer cost barrier is higher and the overall MMBtu savings are greater than a standard ASHP program offering. The incentive levels for the EO pilot are designed to help overcome the customer barriers and achieve the displacement of the fossil fuel heating source. The initial incentive level for the EO pilot will be $1,250/ton, which aligns with a similar offering in Massachusetts. This level may be adjusted as Liberty and the NH Utilities gain experience and customer feedback during the pilot.

Post Inspections and Survey

Post-installation inspections will be conducted for all EO pilot participants. An EM&V survey will be provided during each inspection. The inspectors will collect the following information:

- If the number of installed HP tons (1 ton = 12,000 Btuh) meets the customer’s heating needs;
- If the existing heating system and heat pump set points are within the pilot parameters;
- If there are working integrated controls (if required as listed above); and
- If the heat pump technologies installed were designed to provide heat to a whole heating zone(s).

Evaluation Plan

The pilot will be accompanied by an evaluation to measure the impacts on total energy consumption (for both heating and cooling, and across all fuels) and to assess program processes, customer behavior, and workforce capacity. Results of the evaluation will guide future decisions on expanding the pilot to a full-scale program. Design of the evaluation can leverage experience gained through similar evaluations happening in other states, such as the EO Impact and Process evaluation currently underway in Massachusetts. The NH EO evaluation will include both impact and process components:

- Pilot Impacts. The evaluation will measure impacts and refine methods for accounting for unregulated fuel savings and electric load increases for fuel-to-electric measures, to support modelling net MMBtu savings that could be claimed under a holistic accounting framework. The evaluation may include analysis of heat pump usage data from integrated control systems, delivered fuels billing data, where available, and whole home electric usage data from the NH Utilities. Requirements for integrated controls and customer releases to obtain delivered fuel records will support these efforts. This analysis will also help determine the extent to which EO could, at scale, lead to load factor improvements by increasing load during times when the transmission and distribution systems are not operating at peak capacity. As noted by the Commission in Order No. 26,322, such load factor improvements may present an opportunity for ratepayers, as non-participants may stand to benefit from increased electricity sales that do not significantly increase transmission and distribution system costs.

- Pilot Processes. The evaluation will assess the pilot design and offerings for tailored ASHP measure bundles, including weatherization and integrated controls, to understand customer behavior and satisfaction, contractor technical capacity and training needs, and equipment configurations and baselines. Post-inspections will be utilized to confirm installation configurations and setpoints, and to survey customers on their plans for using the heat pumps and modifying set points, alternative equipment baselines they considered, and their satisfaction with contractors, the installation processes, and the rebate fulfillment process. The evaluation is also expected to include surveys or interviews with contractors to obtain feedback on issues such as training or capacity needs.

Although the pilot is not subject to cost-effectiveness requirements and Liberty and the NH Utilities have not modelled planned savings, average project savings are expected to be in line with those from the EO study done under the oversight of the NH Benefit Cost Working Group.[37] This study and its associated planning model were based on a Massachusetts EO model and adapted to include New Hampshire specific inputs such as fuel cost data, weather data, saturation of various air conditioning technologies, and the regional electric generation mix. Table 6.7 provides estimated fossil fuel and electric impacts for the four scenarios expected to comprise the majority of pilot projects: oil and propane furnaces displaced by a central ASHP and oil and propane boilers displaced by ductless heat pumps.

37 Navigant, Energy Optimization. Sep. 12, 2019. See https://puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2019-10-31_STAFF_NH_ENERGY_OPTIMIZATION_STUDY.PDF and https://puc.nh.gov/Electric/Reports/20190805-PUC-Electric-NH-Energy-Optimization-Model.xlsx.

Table 6.7. EO Estimated Energy Impacts

Baseline Equipment	Replacement Equipment	Annual Energy Savings on MMBtu Basis (MMBtu/yr)	Propane Annual Savings (MMBtu/yr)	Oil Annual Savings (MMBtu/yr)	Electric Annual Savings (kWh/yr)	Electric Heating Savings (kWh/yr)	Electric Cooling Savings (kWh/yr)	Electric Heating Peak Demand Savings (kW)	Electric Cooling Peak Demand Savings (kW)
Oil Furnace + Baseline A/C Blend	Central HP + Oil Furnace	37.81	0.00	49.02	-3285	-3963	678	-1.630	0.610
Propane Furnace + Baseline A/C Blend	Central HP + Propane Furnace	51.67	68.83	0.00	-5027	-5705	678	-1.630	0.610
Oil Boiler + Room A/C/No A/C Blend	Ductless HP + Oil Boiler	46.11	0.00	57.82	-3433	-4231	799	-1.090	0.970
Propane Boiler + Room A/C/No A/C Blend	Ductless HP + Propane Boiler	63.53	81.19	0.00	-5176	-5975	799	-1.095	0.970

Note: Negative savings values reflect increased consumption. Cooling baselines are based on a statewide blend of A/C penetration for central and room A/C systems.

7. <u>CONCLUSION</u>

The purpose of the LCIRP is to provide the Commission with an understanding of the resource planning process employed by the Company to meet its obligation to provide safe, reliable, and least-cost electric service to its customers.

Key results and findings of the LCIRP include:

- Under the extreme weather scenario, Liberty's summer peak demand is projected to grow an average of 0.87% per year over the 2021 to 2037 planning period. Winter peak demand is projected to grow 0.74% per year on average over the same time period. These growth rates incorporate forecasted PV and electric vehicle charging projections for New Hampshire.

- The Company's five-year capital budget is $124 million, with spending on mandated and growth programs representing 41% of the budget, and spending on discretionary items representing 59% of the budget;

- The Company's distribution planning process integrates non-wires alternatives, although the Company's pursuit of non-wires alternative solutions requires a more detailed analysis of the benefits and costs, including technical studies that would require additional resources;

- The LCIRP assumes a "business as usual" scenario for energy efficiency, recognizing there is an ongoing Energy Efficiency Resource Standard ("EERS") proceeding that may affect future energy efficiency programs;

- The LCIRP includes known Distributed Generation ("DG") interconnections;

- The key impacts of the Company's LCIRP on environmental, economic, and energy price and supply impact on the state include the following:

    - The Company's competitively sourced energy supply procurement process, consistent with the Settlement Agreement approved by the Commission in Order No. 24,577 (Jan. 13, 2006), ensures energy supply is delivered to customers at the lowest reasonable cost, while considering certain financial and qualitative criteria.

- The Company's renewable energy credit procurement, energy efficiency programs, and net metering program provide economic and environmental benefits to the state by supporting jobs in the renewable energy industry and reducing reliance on sources of electric generation produced outside the state that emit greater amounts of pollutants.

- The integration of non-wires alternatives into the Company's distribution planning process has the potential to provide economic and environmental benefits to the state through lower costs to the customer and the reduction of peak loads.

These results and findings are consistent with RSA 378:37 *et seq*.

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