STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 23-039

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Distribution Service Rate Case
Advanced Metering Infrastructure

DIRECT TESTIMONY

OF

DMITRY BALASHOV

AND

ANTHONY STRABONE

May 5, 2023

Liberty™

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I. INTRODUCTION

Dmitry Balashov

Q. Mr. Balashov, please state your full name and business address.

A. My name is Dmitry Balashov, and my business address is 354 Davis Road, Oakville, Ontario, Canada.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty hereinafter referred to as "Liberty" or the "Company."

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Political Science degree from the University of British Columbia in Vancouver, BC, Canada, which I completed in 2005. I also obtained a master's degree in Public Administration with a concentration in energy policy from Queen's University in Kingston, ON, Canada, completed in 2008. Finally, I obtained an Executive Master of Business Administration degree from the Rotman School of Management at the University of Toronto, ON, Canada, which I completed in 2018.

I started my electricity sector career in 2007 at the Transmission and Distribution Policy Division of Ontario's Ministry of Energy, where I held several advisory positions in support of both electrical infrastructure planning and regulatory policy matters. Between 2013 and 2017, I was employed by Toronto Hydro-Electric System Limited ("THESL") – Canada's largest urban distribution utility at the time – where I worked as a Lead of Process and Analytics. My position primarily entailed identifying, obtaining regulatory approval for, and implementing a variety of operations and capital planning and asset management initiatives aimed at enhancing system reliability and labor and capital productivity. Between January 2017 and February 2021, I worked as a Director of Utility Strategy and Economic Regulation at METSCO Energy Solutions Inc. – a utility sector engineering and asset management consulting company. My primary area of responsibility was the development of risk-based asset management plans that helped transmission and distribution utility customers identify, pace, and prioritize the highest-value capital projects and maintenance program enhancements, based on objective quantitative analysis of asset health, connectivity, and reliability performance. I joined Liberty Utilities (Canada) Corp. ("LUCo") in February of 2021 as a Senior Director of Policy and Strategy and transitioned to my current role of Senior Director, Grid Modernization in early 2022.

Q. Please describe your duties at Liberty.

A. I am employed by LUCo as a Senior Director, Grid Modernization. In this capacity, I oversee the development and implementation of a variety of initiatives across LUCo's electrical subsidiaries. These include setting and supporting the implementation of LUCo's Advanced Metering Infrastructure ("AMI") strategy through specific deployments, implementation of Electric Vehicle ("EV") charging programs and supporting operational and rate design frameworks, design and implementation of risk-based asset analytics and capital planning frameworks, and execution oversight on a variety of analytical studies aimed at proactive and evidence-based modernization of electricity transmission and distribution systems owned by LUCo's electric utility subsidiaries.

While I am a corporate employee based in LUCo's head office in Canada, in performing my duties I work closely with local engineering, planning, operations, and regulatory subject matter experts located directly in the companies' service territories, including those overseeing Liberty's electric operations in New Hampshire.

Q. Have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. No, I have not.

Q. Have you testified in other regulatory jurisdictions?

A. Yes, I have testified on behalf of LUCo before the Kentucky Public Service Commission and the Missouri Public Service Commission, along with submitting written evidence to several Canadian utility sector regulators, including the Ontario Energy Board, the Manitoba Public Utilities Board, and the Alberta Utilities Commission.

Anthony Strabone

Q. Mr. Strabone, please introduce yourself.

A. My name is Anthony Strabone, my business address is 15 Buttrick Road, Londonderry, New Hampshire, and I am employed by Liberty Utilities Service Corp. ("LUSC"). I am the Senior Director of Electric Operations for LUSC. In that capacity, I am responsible for the safe and reliable operation, design, and maintenance of the electric system for Liberty in New Hampshire.

Q. On whose behalf are you submitting this testimony?

A. I am submitting testimony on behalf of Liberty.

Q. Please describe your educational background and training.

A. I graduated from Merrimack College in 2004 with a Bachelor of Science degree in Electrical Engineering. I received a Master's of Business Administration from Southern New Hampshire University in 2006. I received a Project Management Professional Certification in 2017 from the Project Management Institute. In 2019, I received my license as a Professional Engineer in the State of New Hampshire.

Q. Please describe your professional background.

A. I joined LUSC in November 2014. Prior to my employment at LUSC, I was employed by Public Service Company of New Hampshire ("PSNH") as a Substation Supervisor in Substation Maintenance from 2010 to 2014. Prior to my position in Substation Maintenance, I was a Substation Engineer in Substation Engineering from 2008 to 2010 and an Engineer in the System and Planning Strategy department from 2004 to 2008.

Q. Have you previously testified before the Commission?

A. Yes, on numerous occasions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Our testimony consists of two parts: Section I of our testimony describes the Company's plan to replace its revenue meters with modern AMI meters and associated hardware and software components. Doing so will ensure continued billing accuracy, improve operating efficiency of meter data collection and processing, and set the stage for further modernization and automaton of Liberty's operations by leveraging the edge computing capabilities and a more robust telecommunications backbone that come standard with the newest generation of AMI.

Section II of our testimony addresses the Company's efforts to secure additional non-rate funding for furthering system resilience by applying for funds available through the Federal Grid Resilience and Innovation Partnership ("GRIP") grant program administered by the U.S. Department of Energy ("US DOE") pursuant to the 2022 Infrastructure Investment and Jobs Act ("IIJA").

III. ADVANCED METERING INFRASTRUCTURE

Q. What is Liberty's proposal regarding AMI in the context of this rate case?

A. The Company proposes to replace its existing population of Advanced Meter Reading ("AMR") revenue meters that are increasingly reaching the ends of their useful lives with AMI meters and associated hardware and software devices. To manage the pace of associated rate increases and maximize the remaining useful life of the existing metering fleet, the Company proposes to implement the AMI functionality in two phases that straddle the current applied-for three-year rate period and the rate period that will follow. As described in more detail below, the AMI project's total estimated cost is $40 million in capital expenditures and $0.25 million in recurring annual operation and maintenance ("O&M") expense. Of the total investment amount forecast to implement AMI, $9.5 million will be between now and the end of 2026. This is the amount sought for approval in this application and will be spent on the following: (1) overall system and meter specification design work, (2) the set-up of a testing environment (a combination of hardware and software tools to ensure all future firmware and rate updates function properly), and (3) delivery of a Head End System ("HES"), along with software integrations between the AMI ecosystem and the customer billing system and other necessary operations software, and the associated technical testing of the system components delivered. The remaining expenditures will be sought for recovery in the Company's next rate case, pending approval of the AMI investments included here. Of the amounts shown in Table 1, the Company is seeking recovery of only the $9.5M in spending proposed in 2026. Below showcases the proposed expenditure profile and annual magnitudes, including the capital expenditure amount specifically sought for approval in this rate period.

Table 1. *Proposed Expenditures*

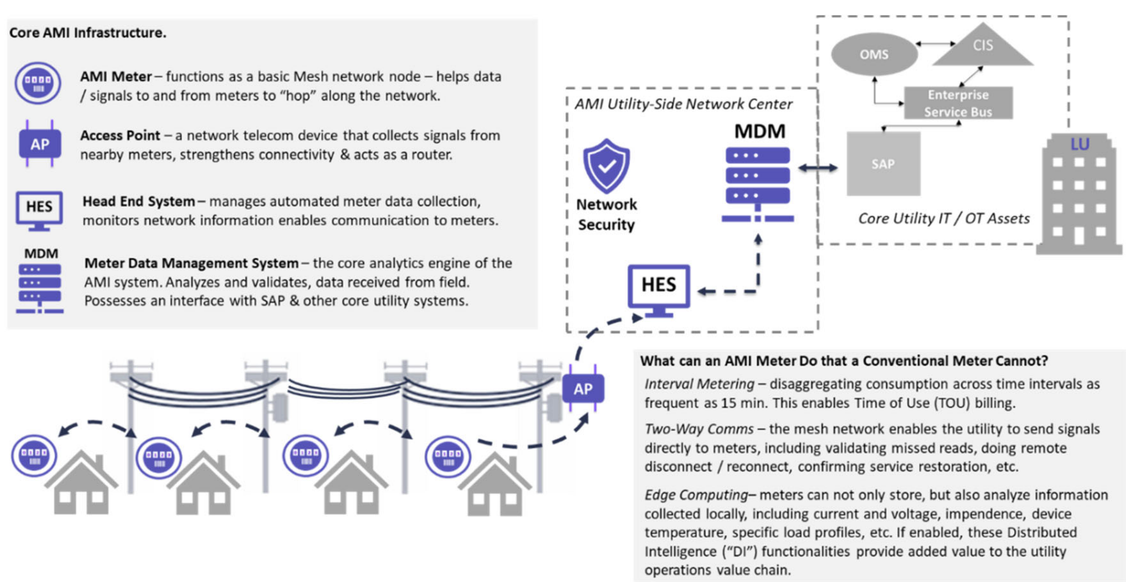
Category	2026	*2027*	*2028*
Capital Expenditures	**$9,500,000**	*$14,866,667*	*$15,633,333*
O&M			*$254,338*

The AMI project and the associated plant additions outlined above associated with the current applied-for rate period have been incorporated into the forecasted Rate Plan identified in Company Witness Anthony Strabone's testimony outlining the forecasted capital investment plan.

Q. Please provide an overview of the proposed AMI technology as distinct from the current metering solutions in use at the Company.

A. AMI is an integrated system of meters, communication devices, and data management hardware and software that enables over-the-air collection of meter data from customers in near-real-time. AMI also maintains a two-way communication between meters and the utility, which provides a variety of operating benefits that go beyond meter data management. Each meter in the AMI network serves as a communication node that supports a mesh network that enables all devices to communicate with the utility's HES, which aggregates the collected data in preparation for analysis performed by the Meter Data Management Systems ("MDM"). Figure 1 below showcases key components of the AMI system, their core functions, and their relation to the rest of the utility's information technology ("IT") and operational technology ("OT") assets.

Figure 1. *AMI System Components and Core Functions Relative to Conventional Meters*



Today, Liberty's revenue meter reading is performed using the AMR platform that includes conventional revenue meters equipped with Encoder Receiver Transmitter ("ERT") devices that enable consumption information to be read from a short distance away by a special collection software. Under the current system, utility staff drive across all parts of the service territory once a month and use a special field collection hardware and software to send a signal sequentially to each meter on the street, which "wakes up" the meter and prompts it to relay the consumption data collected over the time since the last month's meter reading.

While AMR technology and data collection process is more efficient than the original utility sector practice of manual meter reading and recording, it is still very time- and asset-intensive since it requires vehicles and staff time to drive across the entire territory and requires dedicated collection hardware and software that perform no functions other than consumption data capturing. Most importantly, however, AMR technology entails a one-way communication channel that is only capable of transferring consumption data when prompted by a collection device in the ERT's vicinity. This makes AMR a single-purpose technology stack, only capable of performing one function. This is in stark contrast with the AMI system that provides opportunities for multiple operating capabilities enabled by two-way communication networks and localized edge computing and sensing capabilities embedded in the new meters. While AMR meters are also capable of performing basic interval metering (i.e., tracking consumption across on-peak and off-peak time tranches) this capability is far less robust, offers less granular time period tracking, lacks the near-real-time aspect of over-the-air data communication, and requires manual configuration for each meter not originally programmed for interval metering.

Q. What operating capabilities over the current AMR solution does AMI technology enable?

A. The specific range of capabilities that a given utility chooses to enable depends on multiple factors, including but not limited to its operating strategy, the technological makeup of its control center and field area communication network, and legislative and regulatory requirements that may require and/or prohibit certain activities. Most commonly, however, AMI deployments leverage the following functionalities:

- Remote service disconnection or reconnection, which, if enabled, avoids costly truck rolls, speeds up service request completion, and supports employee safety.
- Outage boundaries establishment or restoration confirmation, enabled by remote meter interrogation to confirm whether it continues to receive electrical service.
- Enhanced customer care experience and customer empowerment to manage bills, by reviewing consumption in near-real-time to identify opportunities for savings or facilitate billing disputes through off-cycle meter readings, etc.
- Remote over-the-air meter firmware upgrades to ensure that the metering fleet is equipped with the latest security and operating system patches.
- A variety of operating insights enabled by edge computing and sensory capabilities embedded within the meters, which can be leveraged through the installation of optional "Distributed Intelligence" applications and/or installation

of additional communication hardware and software, which, among others, can monitor and send the utility's control room alerts on the following events:

- Voltage Sag (power quality issues);
- Excessive Electrical Impendence (potential precursor to outage events);
- Temperature (potential indication of fires);
- Damaged Neutral Events (potential customer-side equipment damage);
- Presence of Electric Vehicles (EVs) or unregistered solar generation installations on the customer side (to help with system and resource planning, ensure employee safety and facilitate device-specific rate design and program marketing efforts); and
- Enablement of Distribution Automation (e.g., autoreclosers / smart switches) and Smart Cities schemes (e.g., intelligent street light operation) by leveraging the core AMI telecom network enhanced by additional signal enhancement and routing devices.

As the preceding list indicates, AMI technology offers a wide variety of incremental capabilities, which continue expanding and evolving, and which in any combination represent a definitive step forward from the currently deployed AMR meters. Contemporary AMI technology also entails a major improvement over the first generation of AMI meters that many North American utilities deployed over the past 12–15 years.

Q. Is Liberty proposing to deploy the AMI functionality primarily because it wants to leverage the above-noted benefits of the technology?

A. No. All the benefits listed above are incremental value drivers to what is first and foremost a need to replace Liberty's population of aged legacy revenue meters as they approach and exceed the end of their useful lives. As of 2022, the majority of the Company's population of meters was between 15 and 20 years in age, with 20 years considered the end-of-life threshold. As such, the primary driver for the project is routine asset lifecycle management. The Company will replace the aged legacy revenue meters and AMR ERTs with new metering infrastructure reflecting contemporary industry standards for electric utilities over the period starting in 2025 and concluding in the next rate period. With more than 111 million AMI meters deployed across the United States as of 2021,[1] AMI technology is firmly the current industry standard for electrical metering technology. Accordingly, Liberty's AMI program responds first and foremost to the need to complete a cyclical renewal of an aged asset class. The additional operating and customer service benefits that this lifecycle management exercise is expected to bring about are the corollaries of this core work that constitute additional value streams.

[1] U.S. Energy Information Administration, https://www.eia.gov/tools/faqs/faq.php?id=108&t=3

Q. How does the Company's plan for AMI comply with the Company's commitment in the settlement agreement approved in Docket No. DE 19-064 related to future rate design?

A. In the settlement agreement approved to resolve Liberty's last rate case proceeding, Docket No. DE 19-064, the Company agreed to develop an Advanced Rate Design Road Map, which was to include (1) an explanation of how Liberty plans to leverage the functionality of its existing and planned investments, particularly meters, to maximize ratepayer benefits, and (2) Liberty's plans for the future of rates for each customer class, including the extent to which the utility plans to rely on innovative rate design techniques such as time-of-use rates, critical peak pricing, etc.

In April 2022, the Company presented a Rate Design Roadmap to the key stakeholders in Docket No. DE 19-064 (New Hampshire Department of Energy,[2] the Office of the Consumer Advocate, the City of Lebanon, Clean Energy New Hampshire, and the New Hampshire Department of Environmental Services) describing a phased approach to achieve innovative rate designs for each of its customer classes. Phase 1 of the roadmap included the implementation of AMI throughout the Liberty service territory over a multi-year period. The AMI implementation is the foundational investment needed to achieve future innovation.

[2] New Hampshire Department of Energy was created in July 2021 and DOE Staff now fill a role that is in some respects similar to the role previously filled by Commission Staff.

Q. Are there alternatives to AMI technology for electric utility metering?

A. From a purely conceptual perspective, there are three paths for metering renewal at Liberty given its current technology: (a) reverting to manually read revenue meters, (b) renewing the current AMR technology stack by upgrading revenue meters and ERTs, and (c) replacing the aged metering fleet with an AMI stack (meters, access points, Head End System).

Path (a) is not recommended, since it would involve reverting to manual meter reading and all associated upstream manual collection, entry, validation, and verification processes that would require an expansion of the current labor force and fleet (and thus O&M expenditures) than is currently dedicated to meter data collection and processing. This would also constitute a further step back from the common industry practice on metering technology and would effectively constrain the Company's ability to plan for and implement further grid modernization and customer service enhancement initiatives.

Path (b) is also not recommended, as it would effectively prolong the operational status quo in terms of meter data collection, outage response, rate design, and customer operations. While walk-by or drive-by AMR meter data collection technology remains available, its deployments are increasingly concentrated in the natural gas and water distribution, where meters do not have a direct connection to electricity service and thus require a multi-year battery life that is sustained because the meter signal is only sent out once a month, when a drive-by collector device "wakes the meter up" and captures a reading. As noted previously, the U.S. Energy Information Administration ("EIA") estimates that nearly 111 million or 70% of U.S. end-use consumers are now served using AMI meters. This is a strong indication that AMI is the standard technology for modern electric utilities.

The Company also does not recommend Path (b) because it would not enable it to realize further operating process efficiencies and enhancements, such as elimination of requirements for drive-by meter data collection, or streamlining of outage identification and response, remote customer disconnect/reconnect, off-cycle meter queries to assist in customer requests, and others. Finally, renewing the AMR technology would also limit the Company's ability to modernize its electricity rate structures that would help customers manage their consumption and/or derive optimal value from newer customer-side technologies like EV chargers and storage batteries. As the Commission is aware, Liberty currently has two EV rate offerings and a Battery Storage Pilot Program. Among other requirements, taking advantage of these newer technological solutions requires a smart meter capable of tracking consumption across hourly periods, which is a core capability of AMI meters. Effectively, replacing the existing legacy meters with an AMI solution is the only path of metering fleet renewal that can keep pace with the rest of the industry and unlock multiple new frontiers of field operations, customer care, and distribution system equipment modernization.

Q. Is AMI a new technology?

A. No. AMI meters have been in use in North America since the mid-2000s and have become a predominant electrical distribution industry metering technology since the early

2010s. The AMI technology stack is not only well understood but has significantly improved both in terms of mesh network connectivity robustness and efficiency. Moreover, the range of edge computing functionalities that the meters themselves are equipped with has substantially expanded as well, enabling additional operating insights listed in the last bullet of our response above. AMI is a well-established technology with 5 to 7 primary vendors on the market who continue to refine and improve their offerings. In fact, the proposed Liberty AMI deployment coincides with many North American utilities already replacing their end-of-life first-generation AMI meters with the newest technological offerings. As such, Liberty would effectively be deploying the latest generation technology, reflecting all operating insights and the resulting technological enhancements to resolve the issues experienced by earlier adopters. This significantly reduces implementation risks on the part of Liberty and its customers.

Q. Are you aware of the recommendations pertaining to AMI deployments made in the 2019 Commission Staff report entitled "Staff Recommendation on Grid Modernization" filed in the docket IR 15-296?

A. Yes. In that document, Staff notes that the grid modernization process is expected to proceed gradually, and as a result recommends that a "cost/benefit analysis be conducted to determine the appropriate level of [Advanced Metering Functionalities] before deployment of a certain type of meter at full scale."[3] Staff also suggests that customers should be able to opt-in to interval meter adoption if desired and pay the incremental

[3] New Hampshire Public Utilities Commission, "Staff Recommendation on Grid Modernization. IR 15-296 Investigation into Grid Modernization" January 31, 2019, at 52.

costs associated with these meters[4] would enable the Company and its customers to implement the following enhancements over time:

- Modernize rate designs for core and customer-specific (e.g., EVs, storage, etc.) offerings by way of highly granular interval data transferred over the air.
- Enable more granular outage data analysis – including simplifying the process for calculating advanced reliability metrics like Customers Experiencing Long Interruption Durations (CELID), Customers Experiencing Multiple Sustained Interruptions (CEMI), Feeders Experiencing More than "X" Sustained Interruptions (FESI-X), and others.
- Help identify opportunities for grid performance enhancements, risk mitigation, or customer participation in new programmatic offerings through the Distributed Intelligence (DI) edge computing technology that can be activated over time.
- Provide a telecommunications backbone for an enhanced DA deployment architecture to help reduce outage occurrences and/or durations over time.
- Establish foundational capabilities for performance optimization and transactional management of distributed energy sources.

While the AMI project is fundamentally driven by the need to renew the aging population of legacy AMR meters, these above-noted strategic benefits add an important transformational dimension to the project.

[4] *Id.* at 55.

Q. Why is the AMI project proposed to straddle two rate periods?

A. This is done to account for three main considerations, including (a) motivation to maximize the remaining useful life of the current metering fleet prior to its replacement; (b) opportunity to pace the significant cost of the AMI investment relative to other investment priorities in the company's plan and thereby manage the aggregate rate impact; and (c) allow time to stabilize the recently implemented Customer First solution and the associated process changes before adding further integrations that AMI would require. The following passages expand on each of these considerations.

Maximizing the Current Meters' Useful Lives: As of 2022, the existing metering population was between 15 and 20 years of age, with 20 years broadly considered as the end of the current meters' useful life. By 2026, when the first phase of the AMI project is completed (the phase included for recovery in this filing), the most recent vintages of these meters will be at 19 years, while the majority will be well beyond the 20-year timeframe. By starting the project at the end of the current period, the Company ensures that it maximizes the value of its current meter fleet investment before initiating any renewal work.

Pacing the Investment Profile: AMI implementation is a complex process that involves extensive feature and process definition workshops, IT integration work, field installation of both the metering and network hardware, and extensive testing at various junctures before commissioning the system. While virtually all the field activities would occur in 2027 or later, completing the planning, design, and IT development and testing work of the "back-end" components in this period enables the Company to deliver an important part of the AMI ecosystem to pace the overall cost impact and ensure that the field deployment work planned in the next rate period focuses largely on field execution and testing of local cluster connectivity and adjusting the network devices until the desired service levels are reached and confirmed.

Managing Pace of Technological Change: The Company has recently finished the deployment of its foundational Customer First system and believes it is important to allow some time for (1) the Company's staff to become fully familiar with its new functionalities, and (2) ensure that the associated process changes have been stress-tested and augmented as necessary. Since the initial phase of the AMI project planned for the 2026 timeframe will require the development of SAP integration and changes to a number of customer care and field processes, it is beneficial to fully entrench the recently introduced and amended tools and processes before introducing another set of tool and process changes that would mandate further change management effort.

Q. What work will take place during the current rate period for which approval is being sought in this case?

A. As proposed, the work that would take place during the current rate period would include the following activities:

- *Defining the Solution*: Hosting a series of solution definition workshops with internal staff and the technology vendor, SAP system vendor, and other impacted solution vendors, as appropriate. Establishing meter hardware configurations (memory, display units, buttons, baseline functions enabled / disabled) to enable order placement in time for what has recently been an 18+ month supply chain queue. Mapping and modifying the meter-to-cash, customer care operations, and field operations processes impacted by the introduction of AMI.

- *Designing the Solution*: developing a detailed Business Solutions Requirements Document ("BSRD") and the supporting Requirements Traceability Matrices to ensure that all current and future state features of the integrated solution and the associated steps of enabling them are carefully mapped out. Designing the technical parameters and the logic of the AMI ecosystem software and integration points with other utility systems. Configuring the alarms sent to the control room and/or smart meter operations team, conducting detailed network telecom propagation studies. Identifying cybersecurity requirements for software and hardware, defining inventory management processes, and other supporting logistics.
- *Building the Solution*: setting up a Meter Farm (a physical set of meters and communication devices that replicate the anticipated field parameters) and setting up the software Test Environment to be validated through rigorous acceptance testing of all the elements of the initial deployment, along with those of future over-the-air firmware upgrades and changes to rate design, etc. Building, configuring, and integrating the software solutions (the HES, Meter Data Management Solution, the Customer Information System ("CIS"), and field operations software solutions as required.

- *Testing the Solution*: developing a rigorous statistical regression-based solution test plan to ensure that all capabilities delivered function as intended under a wide variety of pre-determined deployment scenarios. This includes functional, system integration, user acceptance and failover testing processes, and a pilot of actual field deployment in a single community.

At the end of the first phase of the AMI project proposed for this rate period, the Company will have substantially completed the deployment of the critical technology “back end" part of the AMI ecosystem, which will enable it to undertake all the testing required for a full-scale deployment while collecting over the air billing data in the piloted location(s).

Q. What parts of the project would still need to be approved by the Commission in a subsequent proceeding?

A. The second phase would be largely dedicated to the actual field deployment of AMI hardware. In addition to replacing legacy meters with new AMI units, AMI network deployment would also take place. This involves the strategic placement of Access Point (“AP”) devices (typically atop distribution poles) that aggregate and move the data collected from and sent to the individual meters toward the Head End System.

The network is constructed gradually by developing geographically adjacent sectors that are eventually integrated into a single AMI mesh network. A key feature of an AMI mesh network is the fact that data transfers between meters and the head end can find their way via numerous paths – “hopping” from one meter and/or AP to another, depending on connectivity at any given moment. Ensuring the network's ultimate performance through extensive sector acceptance testing is largely the focus of the remaining portion of testing work required at this stage. Ahead of the go-live date, all business processes developed during Phase 1 would be revisited and modified where necessary, while a Smart Metering Operation Center ("SMOC") team would be set up to oversee the ongoing performance of the network.

Q. Over how many years does Liberty anticipate completing the second phase of the AMI Project?

A. On a preliminary basis, the Company expects that the second phase of the project will require approximately three years.

Q. What other activities related to AMI will the Company undertake in the interim?

A. Yes. The Company intends to submit an application for the AMI project funding to the US DOE through the Topic Area 2 application process for the Grid Resilience Innovation Partnership ("GRIP") program during the second annual project proposal intake window expected to commence in December 2023. As discussed in Section II of this testimony, the Company has already submitted one GRIP Concept Paper in the first tranche of the program, which it will develop into a full application. In addition, the Company's affiliate Liberty CalPeco has submitted a full IIJA GRIP application for AMI funding in March 2023. Liberty will incorporate the learnings from its affiliate's application process into its own effort. If successful, upwards of 50% of the project could be funded by the DOE, providing a significant rate relief. In addition to the GRIP program, Liberty will explore other Federal and State-level grant opportunities that may help offset the costs of this important investment.

Q. Has Liberty selected a technology vendor for the AMI project?

A. Yes, Liberty selected Itron as the technology partner for this implementation. Itron is an AMI industry leader, with more than 200 million communication devices across utilities around the globe. Itron has been an AMI deployment partner for the Company's corporate parent since 2019.

Q. How did the Company select Itron as the AMI vendor?

A. Itron was selected by Liberty's parent company in 2019 through an evaluation process that explored the technical, financial, and operational dimensions of potential deployments by leading AMI industry providers. Itron's current technology stack and future roadmap were determined to be best in class, while the cost estimates reflected industry norms. In 2022, Liberty and LUCo's other electric affiliates consulted with Util-Assist Inc. – a consulting company specializing in AMI deployments -- to confirm the AMI industry and vendor technology dynamics several years after the initial assessment. Util-Assist's recommendation confirmed that Itron remained an industry leader in 2022.

Q. Does Liberty or LUCo have any practical experience of collaborating with Itron to rely on in this deployment?

A. Yes. Itron and Liberty completed a major successful deployment of AMI technology at Liberty's electric affiliate Liberty Empire District Electric Company ("Liberty Empire"). The project spanned four states (MO, KS, AR, OK), deploying approximately 170,000 customer meters. The project was completed on time and on budget. Since the completion of Liberty Empire's deployment project, Liberty continues collaborating with Itron on ongoing issues (e.g., software lifecycle, analytics pilots) and planned deployments in other utilities.

Q. Has Liberty selected a specific Itron technology for deployment?

A. Yes, the Company has selected Itron's Gen5 Riva ("Gen5") technology as the AMI platform it intends to implement. Gen5 is Itron's core AMI technology that has been and continues to be deployed at utilities like Pacific Gas and Electric, Florida Power and Light, Potomac Electric Power Company, Commonwealth Edison, Tampa Electric Company, and others across the United States and Canada. The Gen5 platform is distinguished by an extremely robust mesh network connectivity and enhanced Utility IQ ("UIQ") head end system and metering unit capabilities, including the following:

- Shorter meter interrogation cycle time and higher read completion per cycle;
- Improved outage and restoration notification management; improved data synchronization between CIS and the head end;
- Significantly streamlined over-the-air firmware upgrade time and efficiency;
- A telecom backbone foundation capable of supporting data flows from and to field operations technology ("OT") tools that require internet service at the grid's edge (e.g., Distribution Automation, Smart Cities);
- A standard functionality of meters to support the collection of instantaneous Voltage and Current readings, effectively enabling all meters to function as

bellwether meters, to help identify system performance optimization opportunities; and

- A growing ecosystem of DI apps (both Itron and third-party developed) that can be installed to provide additional operating insights using the sensory and computational tools within the meters and/or data from third-party sensors.

As confirmed with the Company's expert third-party advisor, Util-Assist, the Itron Gen5 technology is a leading solution on the market, with multiple major utilities undergoing the renewal of their first-generation AMI technologies choosing Gen5 as their new metering platform.

Q. Were other Itron technologies considered as an option?

A. Yes, Liberty also considered Itron's previous flagship AMI solution, OpenWay Riva, which was deployed at Liberty's Empire affiliate. The Company conducted an internal comparative study between the two technologies and a hybrid option (an OpenWay Riva solution configured to enable eventual transition to the Gen5 communications protocol). However, the options involving the OpenWay solution ultimately proved infeasible because Itron informed the Company that it no longer planned to offer new wholesale deployments of the older solution by the time Liberty's AMI Project commenced.

Q. Will the proposed Gen5 system benefit from any synergies associated with Liberty's current and future AMI deployments in its other operating companies?

A. Yes. The key near-term benefit stems from the fact that both the proposed Gen5 system and OpenWay system deployed at Empire are supported by the same Meter Data

Management ("MDM") system known as IEE. This will create capital cost synergies as the New Hampshire customers will only be required to pay the applicable licensing fees along with local integration costs while benefitting from the foundational development work already completed. In addition, Liberty will be able to rely in part on the implementation and network management expertise of Liberty's corporate and Empire employees. As the Company's other affiliates deploy AMI solutions in the future, opportunities for other synergies will likely emerge as well.

Q. Does the proposed AMI project comply with the requirements of RSA 374:62 as it applies to "Smart Meter Gateway Devices"?

A. Yes, it does. For clarity, the referenced statute requires that utilities intending to install "smart meter gateway devices" must obtain written consent from all customers on whose premises such devices are being deployed. Liberty believes that its proposed project is compliant with this requirement in that the proposed technical configuration of GenX meters that would be deployed will not qualify them to meet the statutory definition of a "smart meter gateway device."

Q. How does Section 374:62 define the smart meter gateway device?

A. As follows:

> [A]ny electric utility meter, electric utility meter component, electric utility load control device, or device ancillary to the electric utility meter, which is located at an end-user's residence or business, and which serves as a communications gateway or portal to electrical appliances, electrical equipment, or electrical devices within the end-user's residence or business, or which otherwise communicates with,

> monitors, or controls such electrical appliances, electrical equipment, or electrical devices.[5]

Q. Why does the Company believe that the proposed AMI deployment does not meet the definition provided above?

A. During the process of meter design workshops that will precede the unit manufacturing ordering, Liberty will ensure that the meter hardware and firmware features (as applicable) responsible for customer-side load disaggregation, specific device identification, or control will remain permanently disabled in all meters. By disabling the features that could otherwise communicate with, monitor, or control customer-side devices, Liberty's meter deployment will not trigger the requirement for written consent to be provided by customers. This design feature will not affect the Company's ability to enable all other use cases identified in this testimony.

IV. PROJECT 4DR: IIJA GRIP RESILIENCE FUNDING APPLICATION

Q. What is Project 4DR and the IIJA GRIP funding mechanism that the Company is applying for?

A. Project 4DR is the name of Liberty's application to the US DOE's GRIP grant program offered under the auspices of the 2021 Bipartisan Infrastructure Law ("BIL"), also known as Infrastructure Investment and Jobs Act ("IIJA"). The GRIP program is one of multiple facets of the IIJA funding framework, which offers federal funding participation in a

[5] RSA 374:62, Smart Meter Gateway Devices. https://www.gencourt.state.nh.us/rsa/html/XXXIV/374/374-62.htm

variety of energy projects proposed by utilities, research institutes, state governments, and other entities.

The Company's specific application was made under Topic Area 1 of the GRIP program, dedicated to innovative proposals that would enhance power system resilience in the face of climate change while providing a variety of economic, social, and environmental benefits to local communities. The funding expectation underlying the program is a 50:50 cost sharing between the US DOE and the applicant (who in the case of a regulated utility would be expected to seek recovery of the non-US DOE portion of the program through a normal rate recovery mechanism). However, in the case of small utilities like Liberty, the US DOE's funding share would increase to 70% if the Company was successful. GRIP applications will be awarded in three annual tranches, with this year being the first such year of eligibility. Each proposal can represent a project of up to five years in duration.

Q. Describe Project 4DR itself.

A. The project's name "4DR" stands for "Four-Dimensional Resilience" for the Company's distribution service territory and stems from the Company's motivation to simultaneously address three of the critical outage contributors in the area that it serves, using different hardening and asset replacement techniques:

- Underground Direct Buried Cable Replacement;
- Reconductoring of Obsolete Overhead Bare Conductor with Covered Conductor;
- Targeted Right-Of-Way Widening to Eliminate or Reduce Outside Tree Fall-Ins.

The fourth "dimension" of resilience is the data collection exercise that would inform future enhancements to the Company's preventative and predictive capital and maintenance work. Data collection would take place in the same areas where active replacement and resilience enhancement work described above is taking place, and some adjacent areas to serve as control groups/calibration data points. Among the data targeted for collection is the following information:

- Online Partial Discharge ("OPD") readings from underground cables before their removal from service and visual inspection of cable segments upon their removal to document and classify the type and extent of damage observed.
- OPD reading from other randomly selected portions of the Company's underground network of similar vintage to those replaced – to help develop a predictive algorithm that would prioritize the remainder of the Company's UG assets based on failure risk.
- Collection of pole and pole-top equipment visual and empirical (e.g., remaining strength, groundline rot) condition data from the assets subjected and/or adjacent to both reconductoring and ROW widening work taking place in the priority areas.
- As with underground work, overhead equipment condition data collected in the immediate vicinity of active project hardening will be supplemented with randomly sampled data from assets of comparable vintage elsewhere in the service territory.

Q. How would the data science element of the project contribute to the Company's resilience?

A. The overarching goal of the data science component of the project is to create an approximation of the overall system condition for both the Company's overhead and underground assets using appropriate statistical sampling and forecasting techniques and capture equipment post-mortem data that would help calibrate asset failure probability analysis that the Company would use in the future. This empirical body of work would act as a baseline for future capital planning and prioritization activities, which would be further refined and supplemented by future inspection data. Together with the active system replacement and resilience reinforcement across the other three "dimensions," the data science component would form a foundation for sustained reliability and resilience planning for the Company.

While active project hardening and replacement work would address the areas that pose the most immediate and significant resilience threats, the data collection and computation work would help establish a foundation for new empirical planning tools that could help move the Company toward a more advanced distribution system planning and asset management practices, such as those contemplated by the ISO 55,000x group of standards. From the practical standpoint, the development of the initial statistical imputation tools in the form of Asset Health Indices would help Liberty pace and prioritize its future capital replacement work – ensuring that expenditures target the portions of the system that are most likely to pose future reliability and resilience risks.

Q. What steps has the Company undertaken to date with respect to this project?

A. The Company submitted a project concept paper to the US DOE for initial evaluation on December 16, 2022. The concept paper includes a significant amount of information that responds to the Company's current state and articulates the benefits that the proposed project would bring – including technical (reliability, asset lifecycle extension), economic, environmental, and broader community benefits including a degree of alignment between the Company's proposal and the government's policy objectives.

On February 4, 2023, the U.S. DOE sent the Company a Letter of Encouragement, that provided some high-level feedback on the Concept Paper submitted and encouraged the Company to proceed to a full application for the funding.

Q. What is known about the competition at the Concept Paper stage of the GRIP application?

A. Applicants recently learned from the US DOE that there were 289 Concept Papers from all 50 States submitted in the "Resilience" Topic Area that Liberty applied for. Of these 289 submissions, only 144, or 49% received a letter of encouragement to proceed further in the application process.

Q. Does Liberty intend to continue with the application process?

A. Yes, the Company intends to do so in early 2024 when the next tranche of applications will be eligible for funding.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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