2026

EVERSOURCE

west monroe

BENEFIT-COST ANALYSIS FOR POTENTIAL DEPLOYMENT OF ADVANCED METERING INFRASTRUCTURE

As of: July 14, 2026

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I. OVERVIEW

West Monroe developed this standalone and comprehensive Benefit-Cost Analysis ("BCA") Report ("BCA Report") for Eversource Energy ("Eversource" or "Company") as a guideline to determine the benefit-cost ratio ("BCR") for deploying advanced metering infrastructure ("AMI") in Connecticut. The Report outlines 19 quantifiable benefits and 18 cost drivers. Each benefit is detailed with a description, calculation methodologies, key inputs, business-as-usual costs, benefit targets, annual benefit calculations, and data to calculate benefit realization. Similarly, each cost includes a description, calculation methodology, key inputs, annual cost calculation and cost granularity, and methodology to track costs. The key costs necessary to unlock the benefit and benefits dependent on the costs are included in the Appendix.

This BCA Report is based on a presumed AMI implementation schedule commencing in early 2027, referred to as Year 1 herein. Project planning is presumed to begin in early Year 1 and back-office system implementation is presumed to begin in earnest by mid-Year 1 to drive toward a three-year AMI deployment beginning by mid-Year 3 and completing by mid-Year 6. The timelines, cost forecasts, and benefit realization assumptions used and the resulting BCA are predicated on timely Public Utilities Regulatory Authority ("PURA") approval of AMI implementation on an accelerated basis using existing technology selections. However, the Company recognizes that an accelerated AMI implementation using existing technology selections is one pathway among multiple prudent paths forward.

The Company has planned a collaborative and solutions-oriented stakeholder engagement process to refine the BCA and use this BCA Report as a guidepost to develop an AMI Deployment and Implementation Plan ("AMI Plan"). The AMI Plan will include AMI deployment and implementation plan details, an time-varying rate discussion, a customer outreach and engagement framework, competitive solicitation summaries, and performance metrics along with this BCA Report as an appendix item. The AMI Plan discusses potential timeline changes that may be necessitated if new competitive solicitation processes are required for primary technology elements. The AMI Plan and this BCA Report also consider an alternative scenario where instead of accelerated AMI implementation, a non-accelerated end-of-life replacement case is pursued.

The Company fully supports PURA's engagement in the investigation of the AMI solution for Connecticut customers and is committed to making the broad-scale, multi-year effort to implement AMI. Given uncertainty around PURA's support for the ultimate timing and pace of the transition, it must be noted that the assumptions underpinning this BCA Report – including projected timelines, costs, and anticipated customer and system benefits – are expressly contingent upon the timely approvals of AMI implementation on an accelerated basis using existing technology selections and associated cost recovery mechanisms. In the absence of such approvals, or in the event of material delay, these foundational assumptions would be invalidated for the BCR calculation, and the Company would be need to reassess the scope, sequencing, and economic viability of the proposed implementation under different assumptions.

II. EXECUTIVE SUMMARY

The electric distribution system is undergoing a fundamental transformation. Historically designed for one-way power flow and predictable demand, today's grid must accommodate bi-directional flows, intermittent generation, and increasingly complex load patterns. These changes introduce new operational challenges and necessitate investments that improve situational awareness, system flexibility, and customer engagement. Without such investments, risks related to reliability, power quality, and cost pressures associated with peak demand are expected to increase over time.

Eversource continues to support Connecticut's clean energy and grid modernization objectives by advancing investments that enable a more dynamic, efficient, and customer-centric electric system. The transition to a cleaner energy future – characterized by increased distributed energy resources ("DER"), electrification, and evolving customer behavior – requires enhanced visibility and control at the grid edge. AMI is a foundational technology that enables this visibility and supports the optimization of distribution system operations in real time.

AMI represents a critical step in addressing these challenges. Unlike the Company's current Automated Meter Reading ("AMR") technology – which captures only a single monthly usage value – AMI enables interval data collection, two-way communication, and near-real time system visibility. This expanded capability supports a wide range of use cases, including improved outage detection, enhanced system planning, customer energy insights, and advanced rate design.

The Company is approaching a pivotal decision point, as a significant portion of the existing AMR meter population is nearing end of life. Rather than reinvesting in a legacy technology for another multi-decade cycle, this filing evaluates the benefits of accelerating a transition to AMI for approximately 1.4 million Connecticut customers. While such a transition requires substantial upfront investment, it enables long-term value across operational, customer, and societal dimensions.

Customers in Connecticut have never been more attuned to what is included in their electric bills. With a heightened focus on affordability and the need to demonstrate the prudence and the value of every dollar spent, AMI provides a unique opportunity to give customers even more transparency and insight into their usage, habits, and bills. Eversource Energy regularly surveys customers and utilizes industry data to inform decisions in order to maximize value, improve customer service and improve operations on a regular basis.[1] These customer surveys consistently exhibit the need to deliver on multiple priorities for them. These include "ways to save," the concept of "customer choice," and even more transparency in their bills.

On "ways to save," Eversource's customers are always looking at ways to adjust their habits to lower their household spending, and to be the most efficient when it comes to their residential/commercial electric use. When Eversource surveys customers, they regularly say that Eversource should prioritize more methods for them to save money and focus on affordability through our communications. With the implementation of AMI for our customers, Eversource can provide them with the vital, near real-

[1] Eversource Voice of Customer surveys

time data which can inform their electric use, helping them to feel more ownership over their use, and provide the potential for them to address affordability on a personal level.

The desire for customers to feel that they have choice over their electric use is a national one. The very nature of utility service is that customers do not have the same consumer options presented to them as they do when it comes to cell phones, clothes, or restaurants. Where you live determines your utility providers. However, it is incumbent upon Eversource as energy delivery providers to meet customers where they are and service their needs in order to improve their customer experience. The implementation of an AMI program achieves that. Once fully operational, customers will have the opportunity to receive high usage alerts, time-varying rates, and other choices based on their own usage. This is one of the unique opportunities where customers' utility provider can provide them with the very demand they are making through our customer surveys.

Bill transparency has become a critical topic for customers and policymakers alike in Connecticut. Legislators and PURA took the progressive, proactive step to provide customers with perhaps the most clear and transparent bills in the country. These steps built more understanding and trust between customers and state regulators, and customers and their utilities. By introducing AMI, customers will have even more data on a more regular basis and can make more informed decisions about their usage. The more customers have at their fingertips when it comes to education and tools to provide insights, the stronger the experience for them as energy consumers.

THE PURPOSE OF THIS BCA

A BCA is a useful tool in assessing the financial attractiveness of a program of major investments such as AMI. The methodology compares the expected financial value of the AMI program benefits to the estimated costs of executing the entire program, with a ratio greater than 1.0 indicating that the investments are justified on a financial basis alone. The BCA is a useful tool for illustrating the financial drivers of the proposed AMI program, but it is not a comprehensive assessment. There are numerous benefits that enhance customers' experiences with their electric service that are not financially quantifiable and therefore are not captured in the BCA. Accordingly, the BCA is just one of several criteria that should be considered in a decision on the future of AMI.

This BCA details nominal benefits over the 20-year analysis horizon that do in fact exceed the nominal costs; however, adjusting for the time value of money (i.e., applying the appropriate cost of capital discount rate) results in a BCA ratio less than 1.0. This output is due to the fact that the costs of the AMI program largely occur in the early years of the analysis horizon, while the quantifiable customer benefits materialize after most of the expenses have been incurred. The result is that the net present value ("NPV") of the total costs exceeds the net present value of the total benefits.

Is it concerning that the projected BCR ratio is less than 1.0? Not necessarily. While the BCA offers a good comparison of the financially quantifiable aspects of the AMI program, it does not reflect many non-financial but nonetheless tangible benefits such as personalized customer usage insights and recommendations, enhanced outage communications, the ability for customers to share their interval usage data, hot socket detection, and other system reliability benefits. Additionally, the second-

generation AMI technology that Eversource proposes to deploy will no doubt birth new use cases leveraging the distributed intelligence capabilities.

It is important to note that the theoretical alternative to AMI deployment is to continue to deploy AMR technology in perpetuity. The ability to procure replacement AMR meters in future decades as the industry migrates to AMI is uncertain, and even if the outdated equipment continues to be accessible, the costs will likely escalate due to declining competition and scale.

SUMMARY OF FINDINGS AND NEXT STEPS

The updated 2026 BCA reflects a comprehensive reassessment of costs and benefits based on refined assumptions, updated market data, and insights from the Company's ongoing AMI deployment in Massachusetts. As a result of the extensive analysis and data presented in this filing, the Company's BCA Report accomplishes the following:

- Initiates project planning early in Year 1 and begin implementing essential back-office systems and the communications network by mid-Year 1 through mid-Year 3. Completes back-office implementations by the start of the 3-year AMI meter deployment in mid-Year 3 and finalize AMI meter deployment by mid-Year 6 enabling benefits to begin accruing as soon as AMI deployment begins.
- Demonstrates an NPV for the proposed costs of $1,557.3 million and associated quantifiable benefits of $1,205.4 million, producing a BCR of 0.77 relative to a non-AMI operations plan. See, Section A.4 - Summary of Results for details.
    - Excluding the carbon reduction benefit yields a 0.66 BCR with $1,557.3 million in costs and $1,208.6 million in associated benefits. See, Section IV – Supplemental BCA Without Carbon Benefits for details.
- Outlines 19 quantifiable benefits with associated benefit availability and benefit realization metrics. See, Section B – Quantifiable Benefits.
    - Benefits are segmented by avoided costs, operational savings, customer savings, environmental, and other.
    - Although benefits are distributed among several categories, the largest source of quantified benefits are Avoided Meter Capital, Systems Cost Avoidance, VVO, Carbon Reduction, Asset Optimization, Improved Restoration Significant Storms, and Bad Debt which collectively represent 86% of the benefit total.
- Discusses seven qualitative and non-quantifiable benefits. See, Section C – Non-Quantified Benefits for details.
- Outlines 18 cost drivers. See, Section D – Costs for details.
    - Costs are segmented by internal labor, external labor, materials, hardware, software, software licensing / fees, corporate overhead, contingency, and AFUDC.

- Tracks average annual incremental internal and external labor across the costs before and during AMI deployment and steady state post-AMI deployment.

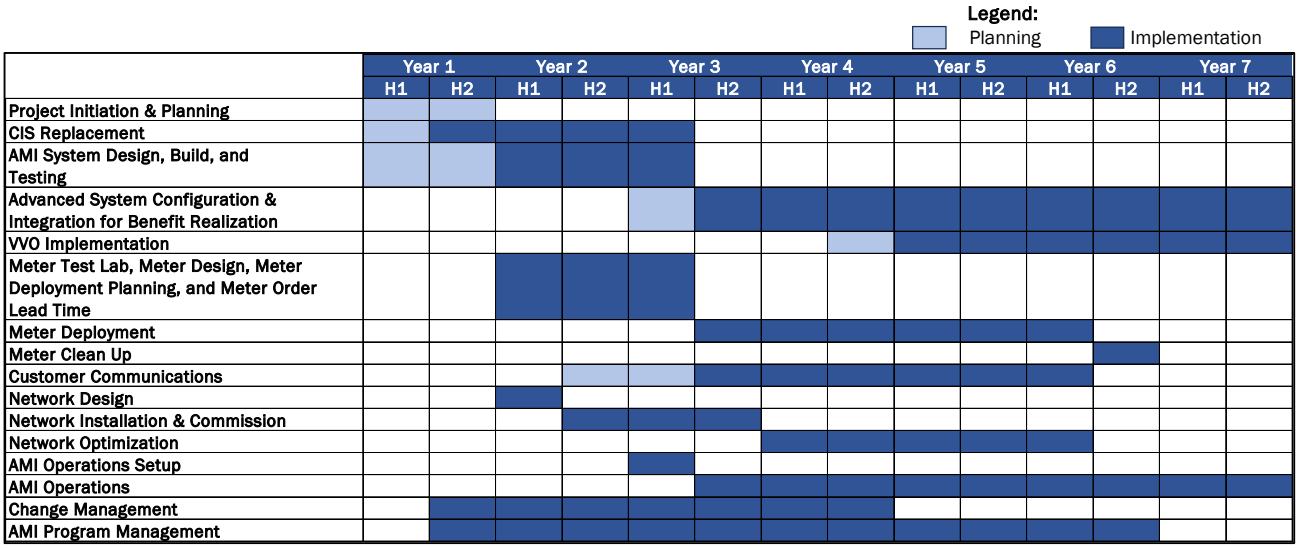
- The 2021 BCA yielded a NPV for the costs of $620.4 million and associated benefits of $743.0 million.
  - From 2021 to 2026, costs increased by $936.8 million, driven by several costs detailed below:
    - Meters increased by $74.5 million from $163.8 million in 2021 to $238.3 million in 2026 primarily driven by an increase in meter and labor costs.
    - Undepreciated Meter Balance increased by $66.2 million from $0 in 2021 to $66.2 million in 2026 as it was not included in 2021.
    - Communications Upgrades increased by $92.7 million from $74.7 million in 2021 to $167.4 million in 2026 primarily driven by an increase in the number of repeaters and access points and associated cost increases.
    - Meter Data Management System ("MDMS") increased by $60.9 million from $44.2 million in 2021 to $105.1 million in 2024 primarily driven by more accurate costs estimates from the Massachusetts AMI Initiative.
    - Customer Information System ("CIS") increased by $229.7 million from $124.5 million in 2021 to $354.1 million in 2026 primarily driven by more accurate costs estimates from the Massachusetts AMI Initiative.
    - Organizational Readiness increased by $62.4 million from $45.5 million in 2021 to $$83.4 million in 2026 primarily driven by more accurate costs estimates from the Massachusetts AMI Initiative.
    - Contact Centers increased by $31.7 million from $45.5 million in 2021 to $77.2 million 2026 primarily driven by increased average handle time and more accurate costs estimates from the Massachusetts AMI Initiative.
    - Customer Experience Portal increased by $52.5 million from $13.5 million in 2021 to $66.0 million in 2026 primarily driven by more accurate costs estimates from the Massachusetts AMI Initiative.
    - Volt/VAR Optimization ("VVO") Enablement increased by $212.3 million from $0 in 2021 to $211.5 million in 2026 million as it was not included in 2021.
    - Cybersecurity increased by $31.1 million from $14.5 million in 2021 to $45.7 million in 2026 primarily driven by more accurate costs estimates from the Massachusetts AMI Initiative.
    - Load settlement increased by $39.4 million from $0 in 2021 to $39.4 million in 2026 as it was not included in 2021.

- From 2021 to 2026, associated benefits increased by $462.4 million, driven by several benefits detailed below:
    - Systems Costs Avoidance increased by $199.5 million from $0 in 2021 to $199.5 million in 2026 as it was not included in 2021.
    - Avoided Meter Capital increased by $82.4 million from $77.9 million in 2021 to $160.3 million in 2026 primarily driven from increased meter and deployment labor costs.
    - Carbon Reduction increased by $88.1 million from $88.7 million in 2021 to $176.8 million in 2026 primarily driven by an increase in the value of carbon avoidance ($/kWh) from $0.044 to $0.083 per kWh.
    - Improved Restoration Significant Storms increased by $92.0 million from $70.4 million in 2021 to $162.4 primarily driven by an increase from 5 to 11 average number of significant storms per year.
    - Asset Optimization increased by $52.6 million from $43.8 million in 2021 to $96.4 million primarily driven by an increase in the number of sensors per feeder and price per sensor estimates.
    - Remote Account Connect/Disconnect decreased by $28.4 million from $60.6 million in 2021 to $32.2 million primarily driven from smaller field operations staff reductions, from 40 baseline staff in 2021 compared to 33 in 2026.

- Includes a summary of a sensitivity analysis identifying the most impactful cost and benefit assumptions and data points to understand the impact of uncertainty in costs and benefit realization. See, Section V – Sensitivity Analysis.
    - The most impactful data inputs include inflation rate, energy sales growth rate, the number of significant storms per year, the CIS system cost avoidance start year, value of carbon avoidance, and TOU/TVR residential participation rate.

It should be noted that the dates assigned to activities and milestones throughout this BCA Report illustrate sequence and timing based on the assumption that a supportive order from PURA is received in early November 2026 that allows the Company to commence work in early 2027. If a supportive framework is not approved by early November 2026 and/or the Company is otherwise not able to commence the AMI Plan in early 2027, the timing estimates cited throughout the BCA Report may no longer be applicable.

Figure 1 – Connecticut AMI Implementation Timeline



From a strictly quantitative perspective, the analysis indicates that upfront costs exceed monetized benefits on a present value basis. However, as in the prior filing, this outcome does not fully capture the total value of AMI. Many benefits – particularly those related to reliability, customer experience, system resiliency, and future innovation – are inherently difficult to quantify and are expected to materially enhance overall value over time. Incremental AMI-enabled capabilities that extend beyond the quantified BCA result materially enhance customer service, safety, and grid resiliency in ways not fully reflected in the quantitative analysis, including:

- Advanced customer bill analytics and load disaggregation, combined with personalized tips and usage data sharing, empower customers to better understand and manage their consumption.
- Customer notifications on outage restoration status, bill projections, and high-bill alerts improve customer communication and provide more transparency around billing.
- Accurate load profiles support improved engineering decisions and more effective energy efficiency and demand response incentive targeting.
- Integration of AMI data with the system operations center (SOC) and the use of AMI to identify downed wires, hot sockets, and high-impedance conditions enhance public safety and grid resiliency.
- An AMI platform can be leveraged to support advanced gas instrumentation in the future.

Collectively, these incremental capabilities strengthen customer engagement, reliability, and safety in ways that are not fully captured in the quantitative BCA, but that provide meaningful additional value to the Company's customers. Overall, AMI should be evaluated as a strategic, enabling investment that supports long-term transformation of the electric grid rather than as a standalone financial project.

III. AMI BENEFIT-COST ANALYSIS

A. BCA FRAMEWORK

A.1 INTRODUCTION

In 2019, PURA embarked on an initiative to accelerate the modernization of Connecticut's electric grid in innovative, cost-effective and equitable ways with AMI as one of four key objectives to achieve a modernized grid. Since 2019, the proceeding for the Equitable Modern Grid Decision has involved extensive stakeholder engagement through public forums, requests for proposals, written comments, technical meetings, and a public hearing, culminating in the issuance of the January 3, 2024 decision for the Company to develop the BCA Report as part of Docket No. 17-12-03RE02. After the issuance of this decision, PURA issued guidance for a regulatory framework for AMI cost recovery as part of Docket No. 17-10-46RE04 in December 2024, which was later rescinded by PURA on July 1, 2026. In light of PURA's renewed engagement on AMI in 2026, the Company has developed an AMI Plan and a detailed benefit-cost analysis, as outlined in this filing.

AMI is a comprehensive metering and communications system that records customer electricity consumption in 15-minute intervals (or more frequently) and transmits measurement over a communication network to a central collection point. To enable the full benefits of AMI, significant infrastructure investment is required beyond metering hardware. Simply put, AMI is a multi-dimensional initiative, fostering a foundational shift in communication between customers and the Company that will enable new functionalities and opportunities for customer savings, while changing how the customer understands and uses electric service. The current meter reading technology utilized by the Company in Connecticut is AMR, where field crews typically collect customer usage once per month by driving a vehicle near the meter.

The Eversource AMI Plan will provide a detailed assessment of the optimal path towards a cost-effective deployment of AMI meters and supporting infrastructure for all Connecticut electric customers. The first principle guiding development of the AMI Plan is to ensure the greatest possible benefit to customers for the associated cost. Based on this premise, the Company conducted a thorough effort to develop the BCA Report, cataloguing all sources of value that AMI will unlock within PURA's nine financially quantifiable benefit categories. Many of these benefits accrue directly to customers. For example, access to usage information and availability of optional TVR/TOU rates will provide customers with new opportunities to manage energy consumption and lower bills. A second set of benefits unlocked by AMI will accrue indirectly to customers. System expenses that are distributed to all customers, such as unbilled usage (including theft and non-technical line losses, can be reduced through initiatives enabled by AMI deployment. Other indirect customer benefits, such as reduced truck rolls, improve the Company's operational efficiency and thus reduce the costs of providing service to customers.

For each of the quantitative and qualitative benefits enabled by AMI, the BCA Report estimates the associated costs required to achieve the desired end-state. In addition to the cost of the meters and

the required communications infrastructure, other costs include back-office IT systems required to collect, process, and store large volumes of data, as well as the systems and tools required to offer TOU and other complex rates and analyze meter data to generate customer and operational insights to deliver the full value of AMI data.

The BCA Report also describes how the optimal deployment leverages the value of existing assets and programs. As a complement to existing reliability and resiliency programs, the AMI system will increase the value proposition of prior capital investments. Data made available with the AMI system will also improve the value of the Company's existing and future conservation and load management ("C&LM") programs. Improved measurement and verification, enabled by AMI, will also provide benefits to C&LM programs. In addition to leveraging existing programs, the Company's AMI deployment strategy incorporates many opportunities to add value to existing assets. Integration with existing systems, including OMS and data analytics platforms, will improve the value of these tools.

This comprehensive and rigorous analysis of costs and benefits, as well as a thorough description of qualitative and hard-to-quantify benefits, reflects a strategic deployment that has the potential to maximize value and deliver the benefits of a modern grid to Eversource's customers.

A.2 COST BENEFIT ANALYSIS OVERVIEW

To ensure a robust and comprehensive BCA Report, the Company relied on the expertise of many internal subject matter resources as well as industry experts. Key Company resources were identified in areas such as Telecommunications; Meter Operations; Meter Reading; Voice of the Customer; Digital Customer Experience, System Operations; Grid Modernization; Rates; Engineering; Finance; Cyber Security; Information Technology; Billing; Contact Centers; Field Operations, Collections and Assistance Programs. The Company also retained West Monroe Partners, a professional services firm with a dedicated Utilities practice that has extensive experience supporting utilities with the development of AMI business cases and regulatory filings.

Based on PURA's direction, the Company calculated benefits in nine categories and documented the assumptions used to quantify those benefits relative to a non-AMI scenario. The benefit categories are: Avoided Meter Costs; Automate Service Orders; Energy and Demand Reduction; System Planning Optimization; Proactive Outage Planning; Early Outage Detection; Energy Theft and Non-Technical Loss Reduction; Write-off Reduction, Customer Empowerment; and Customer Satisfaction. The Company has also characterized additional qualitative categories without quantifiable financial benefits, which include improved customer experiences through usage and bill projections, which will take the surprise out of utility bills, better information and faster response during outages, and detection of safety issues such as hot meter sockets. Additionally, customers will receive detailed usage analyses and have the ability to share their usage data with third-party service providers, helping them to access savings and explore other technology opportunities.

Also identified and documented are eight cost categories and their associated assumptions to quantify the costs required to achieve the benefits of AMI. The cost categories include Meter; Communications;

Back Office Systems; Labor and Standard Operating Plan; Supporting Services and Platforms; Voltage Var Optimization ("VVO"); Customer Experience; and Data.

The assumptions made in the BCA Report were based on a combination of industry benchmarks Company subject matter expertise, and experience from the Company's in-flight AMI deployment in Massachusetts. From February through April 2026, West Monroe hosted over 40 workshops and meetings with Company employees, consulted with over 50 stakeholders, and collected over 400 unique data points across 19 quantifiable benefits and 18 costs. The BCA Report analyzes the comprehensive investments, including upfront and ongoing costs and benefits, annually over a 20-year time horizon and present valued to 2026 dollars using a 7% discount rate as required in Docket No. 17-12-03RE02 to determine the BCR.

A.3 DEPLOYMENT TIMELINE

As illustrated in Figure 2, and contingent upon a favorable ruling from PURA by Q4 2026, the Company plans to begin project planning in early Year 1, begin implementation of key back-office systems in mid-Year 2, begin a 3-year AMI meter deployment by mid-Year 3, and complete deployment by mid-Year 6.[2] The benefits begin accruing in Year 3 after AMI deployment begins, as shown in Figure 3. Timing for each of the costs and benefits is detailed in Section B – Quantifiable Benefits and Section D – Costs.

[2] Key back office systems implementation duration will be five and a half years and meter deployment will be three years.

Figure 2 - Cost Timeline[3]

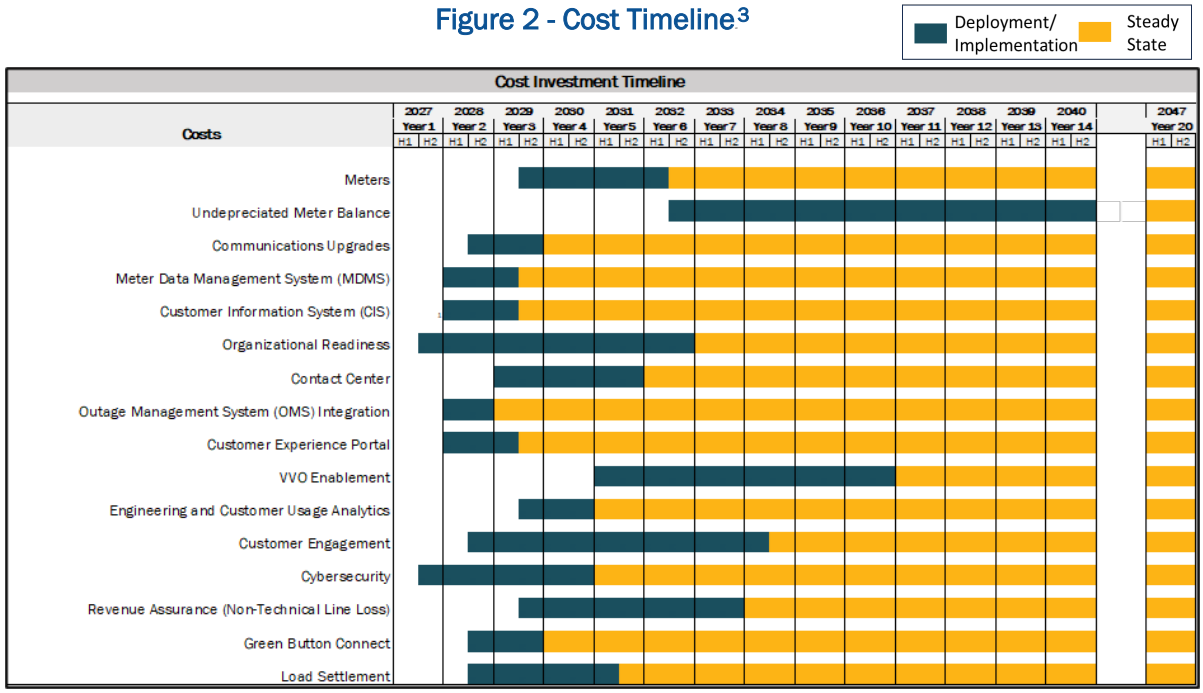
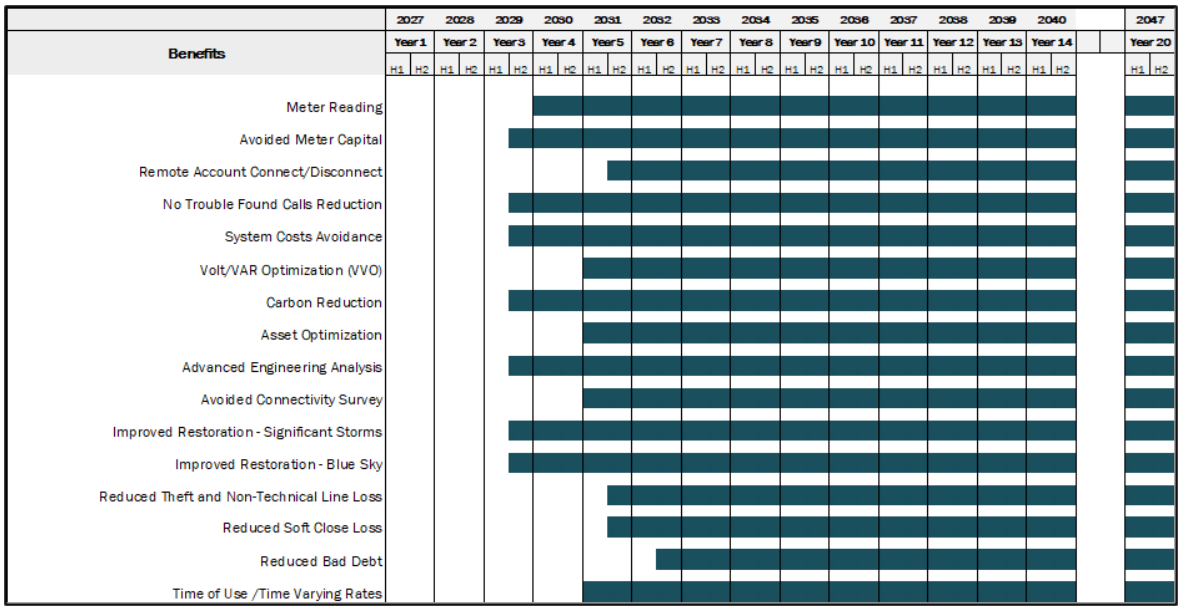


Figure 3 - Benefits Timeline[4]



[3] Cost timeline includes cost categories with non-zero cost estimates. Additional cost categories not shown in timeline include Incremental Labor and Data Storage and Processing.
[4] Benefits timeline includes benefits with non-zero quantified benefits. Additional benefit categories not shown in timeline include Customer Targeting for Incentives, Improved Reliability, and Billing Accuracy and Timeliness.

A.4 SUMMARY OF RESULTS

The BCA results include a summary of the benefits and costs resulting from an AMI deployment for all customers in Connecticut. With respect to benefits, the Company classified the financial impact into five categories:

- **Avoided Costs:** Represents labor, equipment, or system costs that Eversource would have incurred over the normal course of business without AMI meters deployed and reduce the cost of doing business and will flow to customers over a longer time horizon.
- **Operational Savings:** Reduces Eversource's operational costs through improved efficiency or revenue collection from AMI.
- **Customer Savings:** Realized directly by customers, either through reduced billing costs or improved reliability.
- **Environmental:** Lowers carbon produced by the system.
- **Other:** Reduces the cost to deploy AMI via procurement-related value.

With respect to costs, the Company classified expected expenditures associated with the AMI components into categories of capital expenditures ("Capital") and operations and maintenance ("O&M") expenditures. As shown in Figure 4, the 20-year nominal benefit-cost ratio ("BCR") is 1.06, or 0.77 on a present value basis.

Figure 4 – High-Level 20-Year Financial Summary

Total 20-Year Cost and Benefit	TOTAL NOMINAL VALUE (in Millions)	TOTAL NPV VALUE (in Millions)
Total AMI Cost	**$2,568.7**	**$1,557.3**
Capital	$1,415.5	$989.6
Operations & Maintenance	$1,153.1	$567.6
Total AMI Benefit	**$2,713.7**	**$1,205.4**
Avoided Cost	$1,481.9	$700.8
Operational Savings	$285.4	$115.3
Customer Savings	$481.8	$195.5
Environmental	$441.3	$176.8
Other	$23.3	$16.9
Net Benefit ($M)	**$145.1**	**-$351.9**
Benefit Cost Ratio	**1.06**	**0.77**

Figure 5 and 6 provide a more detailed disaggregation of the capital and O&M nominal costs over a 20-year period and a six-year period, respectively.

Figure 5 - 20-Year Capital and O&M Nominal Costs

Cost Category	Cost	20-Year Nominal Capital		20-Year Nominal O&M	
Meters	Meters	$340.0M	**$476.8M**	$0.0M	**$0.0M**
	Undepreciated Meter Balance	$136.7M		$0.0M	
Communications	Communications Upgrades	$160.5M	**$160.5M**	$141.7M	**$141.7M**
Back Office Systems	Meter Data Management System (MDMS)	$68.8M	**$310.1M**	$106.0M	**$467.3M**
	Customer Information System (CIS)	$212.5M		$324.3M	
	Load Settlement	$28.8M		$37.0M	
Labor and Standard Operating Plan	Organizational Readiness	$100.2M	**$101.1M**	$4.2M	**$190.3M**
	Contact Center	$0.6M		$140.6M	
	Revenue Assurance (Non-Technical Line Loss)	$0.2M		$45.4M	
Supporting Services and Platforms	OMS Integration	$11.1M	**$63.6M**	$3.7M	**$168.3M**
	Customer Experience Portal	$29.5M		$86.5M	
	Engineering and Customer Usage Analytics	$22.1M		$62.8M	
	Green Button Connect	$0.9M		$15.3M	
VVO Enablement	VVO Enablement	$297.5M	**$297.5M**	$79.8M	**$79.8M**
Customer	Customer Engagement	$0.0M	**$0.0M**	$22.7M	**$22.7M**
Data	Cybersecurity	$5.9M	**$5.9M**	$83.1M	**$83.1M**
	Data Storage and Processing	-	-	-	-
Total		**$1,415.5M**		**$1,153.1M**	

Figure 6 – 6-Year Capital and O&M Nominal Costs

Cost Category	Cost	6-Year Nominal Capital		6-Year Nominal O&M	
Meters	Meters	$302.4M	**$309.2M**	$0.0M	**$0.0M**
	Undepreciated Meter Balance	$6.8M		$0.0M	
Communications	Communications Upgrades	$91.1M	**$91.1M**	$19.8M	**$19.8M**
Back Office Systems	Meter Data Management System (MDMS)	$63.0M	**$304.3M**	$21.0M	**$127.4M**
	Customer Information System (CIS)	$212.5M		$102.4M	
	Load Settlement	$28.8M		$4.0M	
Labor and Standard Operating Plan	Organizational Readiness	$98.1M	**$99.0M**	$4.2M	**$65.3M**
	Contact Center	$0.6M		$55.2M	
	Revenue Assurance (Non-Technical Line Loss)	$0.2M		$5.9M	
Supporting Services and Platforms	OMS Integration	$11.1M	**$63.6M**	$1.0M	**$30.1M**
	Customer Experience Portal	$29.5M		$17.9M	
	Engineering and Customer Usage Analytics	$22.1M		$9.3M	

Cost Category	Cost	6-Year Nominal Capital		6-Year Nominal O&M	
	Green Button Connect	$0.9M		$2.0M	
VVO Enablement	VVO Enablement	$97.3M	**$97.3M**	$3.0M	**$3.0M**
Customer	Customer Engagement	$0.0M	**$0.0M**	$18.2M	**$18.2M**
Data	Cybersecurity	$5.9M	**$5.9M**	$18.9M	**$18.9M**
	Data Storage and Processing	-	-	-	-
Total		**$970.3M**		**$282.8M**	

As shown in Figure 5, 69% of capital costs are incurred over six years, which includes the implementation of the back-office systems, implementation of communications network upgrades, and AMI meter deployment.

Figure 7 illustrates the difference between the nominal and present value as BCR is dependent on the timing of costs and benefits. While some benefits begin to accrue as soon as AMI meter deployment commences in Year 3, other benefits are dependent on the completion of AMI meter deployment and other enabling investments, such as VVO. VVO is a six-year implementation that does not begin until Year 5, meaning that the full realization of benefits driven from VVO does not begin until Year 11.

Figure 7 – Annual Nominal Costs and Benefits Over 20 Years

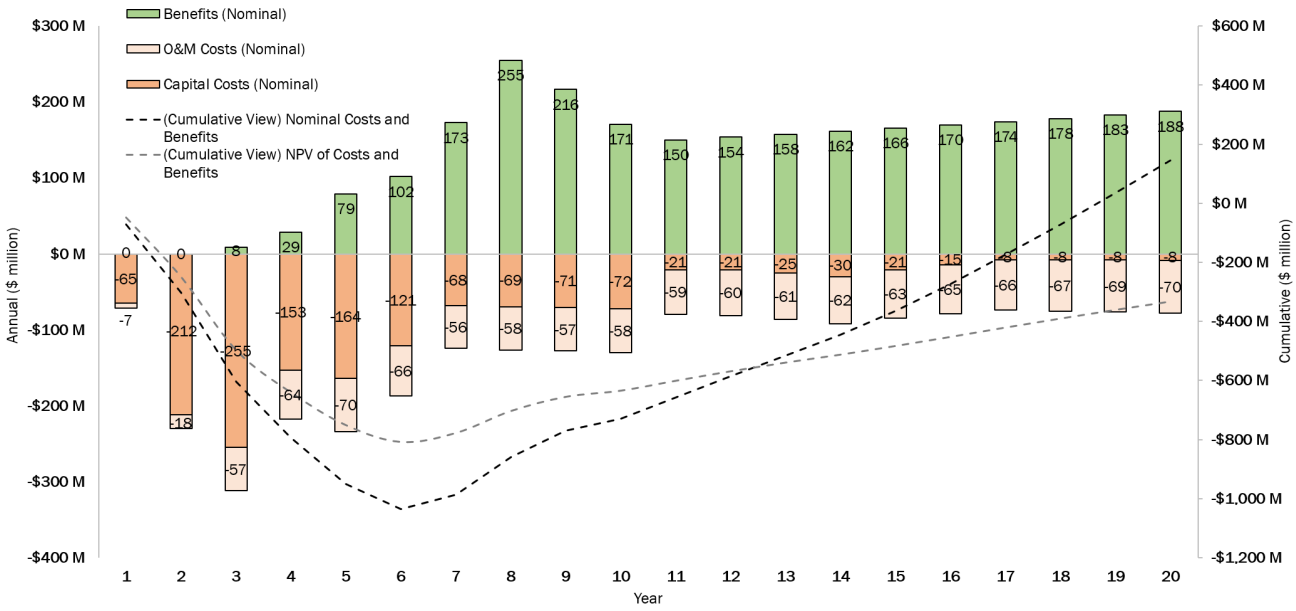
Total 20-Year Cost and Benefit	Nominal Value ($M)	NPV Value ($M)
Total AMI Cost	**$2,568.7**	**$1,557.3**
Meters	$340.0	$238.3
Undepreciated Meter Balance	$136.7	$66.2
Communications Upgrades	$302.2	$167.4
Meter Data Management System (MDMS)	$174.8	$105.1
Customer Information System (CIS)	$536.8	$354.1
Organizational Readiness	$104.5	$83.4
Contact Center	$141.3	$77.2
Incremental Labor (Included in each Cost category)	$0.0	$0.0
Outage Management System (OMS) Integration	$14.8	$11.6
Customer Experience Portal	$116.0	$66.0
VVO Enablement	$377.3	$212.3
Engineering and Customer Usage Analytics	$84.9	$46.4
Customer Engagement	$22.7	$16.1
Cybersecurity	$89.0	$45.7
Revenue Assurance (Non-Technical Line Loss)	$45.7	$20.4
Green Button Connect	$16.2	$7.6
Data Storage and Processing (Included in IT Systems Cost Categories)	$0.0	$0.0
Load Settlement	$65.8	$39.4
Total AMI Benefit	**$2,713.7**	**$1,205.4**
Meter Reading	$50.8	$21.2
Avoided Meter Capital	$343.9	$160.3
Remote Account Connect/Disconnect	$77.5	$32.2
No Trouble Found Calls Reduction	$13.0	$5.7
System Costs Avoidance	$393.8	$199.5

Total 20-Year Cost and Benefit	Nominal Value ($M)	NPV Value ($M)
Volt/VAR Optimization (VVO)	$409.0	$163.8
Carbon Reduction	$441.3	$176.8
Asset Optimization	$169.2	$96.4
Advanced Engineering Analysis	$88.5	$38.7
Avoided Connectivity Survey	$16.8	$6.7
Improved Restoration – Significant Storms	$363.2	$162.4
Improved Restoration – Blue Sky	$5.7	$2.5
Reduced Bad Debt / Write-offs	$188.7	$74.5
Reduced Theft and Non-Technical Line Loss	$39.6	$16.5
Reduced Soft Close Loss	$57.1	$24.3
Time of Use / Time Varying Rates	$55.4	$23.9
Customer Targeting for Incentives	$0.0	$0.0
Improved Reliability (Inc. Advanced Engineering and Imp. Restoration)	$0.0	$0.0
Billing Accuracy and Timeliness	$0.0	$0.0
Net Benefit ($M)	**$145.1**	**-$351.9**
Benefit-Cost Ratio	**1.06**	**0.77**

Figure 8 provides detailed 20-year nominal and present value costs and benefits, which collectively yield a BCR of 0.77. Annual data for each of the costs and benefits is detailed in Section B – Quantifiable Benefits and Section D – Costs. Sensitivity analysis across several of the key inputs that have an outsized impact to drive the BCR either direction is analyzed across a range of values in Section V – Sensitivity Analysis.

From a purely quantitative standpoint, the net present value of upfront costs of such a significant investment are in excess of the net present value of quantifiable benefits that accrue as a direct result of the investment; however, there are several significant non-quantified customer, operational and societal benefits that should be considered when evaluating AMI feasibility. Further, AMI will produce future and unplanned use cases and benefits that provide value to customers, so an initial BCR will almost certainly underestimate potential value. AMI is a foundational investment that would modernize Eversource's customer experience and infrastructure, promote energy conservation, and increase system resiliency, while driving economic benefit and reducing environmental impact.

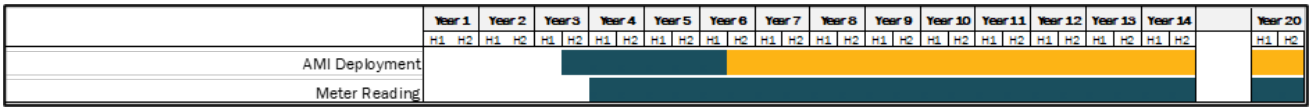
Figure 8 – Detailed 20-Year Financial Summary By Cost and Benefit



B. QUANTIFIABLE BENEFITS

B.1 AVOIDED METER COSTS

(i) Meter Reading



a. Description

Since its initial deployment in 2000, the Company has fulfilled its meter reading needs through drive-by AMR technology. The infrastructure for this system consists of vehicle-mounted collectors and the software to read, store, and process meter consumption data. The cost of meter collection also includes labor associated with the drive-by collection system, which involves data collection once a month for billing purposes, as well as off-cycle reads related to start/stop service requests. The Company staggers the collection of meter data by cycles to effectively read, bill, and manage customer calls in such a manner that not all data collection and billing take place on the same day.

With the use of a wireless communications network, the AMI system will deliver operating cost reductions and lower AMR equipment and associated software costs. The proposed AMI technology uses wireless telecommunications for the collection of meter data, which avoids the drive-by AMR data collection costs. AMI meter consumption data can also be collected more frequently as needed. The AMI communications network also enables firmware upgrades over the air, eliminating the need to

physically visit meters to perform updates. Finally, the reduction in miles driven for meter reading provides additional carbon reduction benefits, although those benefits have not been quantified.

The Company's meter-reading team reads both electric and gas meters. Of the 408 total routes as of April 2026, 191 (47%) are combined electric and gas, 210 (51%) are electric-only, and 7 (2%) are gas only. Given that the Company's current AMR system collects both gas and electric usage data, the BCA reflects the fact that these savings cannot be fully realized in overlapping service territories and that AMI opt-out customers and any exceptions could be dispersed throughout the electric-only service area. This benefit is considered an Avoided Cost, meaning that it represents labor, equipment, or system costs that Eversource would have incurred over the normal course of business without AMI meters deployed.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

To calculate the savings related to this activity, the Company assessed the staff required for meter reading services post-AMI deployment and in a business-as-usual scenario where the Company will maintain current staffing. The post-AMI staffing assumes that natural attrition will eventually result in a steady state of 14 FTEs, from a business-as-usual staffing level of 22 FTEs – resulting in a reduction of 8 FTEs. Based on current customer distribution and AMI opt-out assumptions, 12 is the minimum number of meter readers needed to ensure that both AMI opt-out customers and exceptions located at any geographic location within the service area can be read every month. Monthly AMI opt-out, exception, and gas reads necessitate a base level of staffing. Since 47% of all current meter reading routes are combined electric and gas, these 12-meter readers will also read all gas customers every month, which limits the amount of avoided cost benefit. The number of meter reading vehicles will also be reduced post-AMI in line with the staff reductions.

<u>Annual Benefit Calculations</u>:

Business As Usual Meter Reading Labor Calculation:		
Average Annual BAU Meter Reading Loaded Labor Costs ($)	X	Inflation (%)
$3,108,476		2%

Post-AMI Deployment Meter Reading Labor Savings Calculation:				
Average Annual BAU Meter Reading Loaded Labor Costs ($)	–	Average Annual Post-AMI Deployment Meter Reading Labor Costs ($)	X	Inflation (%)
$3,108,476		$2,148,201		2%

Business As Usual Meter Reading Non-Labor Calculation:		
Average Annual BAU Meter Reading Non-Labor Costs ($)	X	Inflation (%)
$159,809		2%

Post-AMI Deployment Meter Reading Non-Labor Savings Calculation:				
Average Annual BAU Meter Reading Non-Labor Costs ($)	–	Average Annual Post-AMI Deployment Meter Reading Non-Labor Costs ($)	X	Inflation (%)
$159,809		$105,663		2%

Business As Usual Meter Reading - Vehicle Spend Calculation:		
BAU Average Annual Meter Reading Vehicle Spend (Electric and Gas) ($)	X	Inflation (%)
$150,845		2%

Post-AMI Deployment Meter Reading - Vehicle Spend Calculation:				
BAU Average Annual Meter Reading Vehicle Spend (Electric and Gas) ($)	-	Post-AMI Deployment Average Annual Meter Reading Vehicle Spend (Electric and Gas) ($)	X	Inflation (%)
$150,845		$131,751		2%

Meter Reading List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Average Annual BAU Meter Reading Loaded Labor Costs ($)	$3,108,476	Current gas and electric meter reading staff including 19 meter readers, 2 meter reading clerks, and 1 supervisor. Meter reading team reads both gas and electric meters, with around 53% for electric-only and around 47% for gas and electric	Annual BAU costs may increase faster or slower than 2% inflation and the amount of staff required to read meters under BAU may increase or decrease depending on meter growth and geography considerations of new meters
Average Annual BAU Meter Reading Non-Labor Costs ($)	$159,813		
Average Annual Post-AMI Deployment Meter Reading Loaded Labor Costs ($)	$2,148,201	Gradual attrition from BAU after year one of AMI deployment to a lower number of steady state staff required: 12 meter readers, 1 meter reading clerk,	Depending on the number and geographic dispersion of AMI opt-out and exception meter reads, the amount of meter readers

Meter Reading List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Average Annual Post-AMI Deployment Meter Reading Non-Labor Costs ($)	$105,663	and 1 supervisor, reaching steady state two years after the completion of meter deployment. The steady state staff numbers are the minimum needed to support electric AMI opt-out and exception meter reads distributed throughout the service area, especially with any routes that do not overlap with gas. Gas meter reading limits the avoided cost benefit	needed to serve these customers could be higher or lower than 12 meter readers. Additionally, the costs for meter reading staff could increase at a rate higher than 2% inflation
BAU Average Annual Meter Reading Vehicle Spend (Electric and Gas) ($)	$150,845	Company cost data: The Company purchased 17 vehicles in 2024 due to supply chain delays in 2020-2023. This number represents a 20-year average to account for large purchases in 2024 at an average all-in cost of $40k per vehicle. There are currently 26 vehicles for 22 meter reading staff. Post-AMI deployment steady state will have 12 staff. Assumes the number of vehicles will reduce by 8 (22-14) in steady state two years after the completion of meter deployment.	Future vehicle spend may exceed this amount or increase faster than 2% inflation The number of vehicles needed could be higher or lower depending on the number of staff, which may vary based on the number of opt-out customers and exception reads
Post-AMI Deployment Meter Reading Vehicle Spend (Electric and Gas) ($)	$131,751		
Meter Reading Vehicle Cost + Full Kit ($)	$40,098	Company cost data	Vehicle costs may increase faster than 2% inflation
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)					
	Baseline Annual Meter Reading Labor Costs	Baseline Annual Meter Reading Non-Labor O&M Costs	Baseline Annual Meter Reading Vehicle Capital Costs	Baseline FCS System Annual Costs	Baseline FCS Equipment Replacement Costs	Total Baseline
Year 1	$3.23	$0.17	$0.15	$0.73	$0.06	**$4.34**
Year 2	$3.30	$0.17	$0.16	$0.74	$0.06	**$4.43**
Year 3	$3.36	$0.17	$0.16	$0.76	$0.06	**$4.52**
Year 4	$3.43	$0.18	$0.16	$0.77	$0.06	**$4.61**
Year 5	$3.50	$0.18	$0.17	$0.79	$0.07	**$4.70**
Year 6	$3.57	$0.18	$0.17	$0.80	$0.07	**$4.80**
Year 7	$3.64	$0.19	$0.17	$0.82	$0.07	**$4.89**
Year 8	$3.71	$0.19	$0.18	$0.84	$0.07	**$4.99**
Year 9	$3.79	$0.19	$0.18	$0.85	$0.07	**$5.09**
Year 10	$3.86	$0.20	$0.18	$0.87	$0.07	**$5.19**
Year 11	$3.94	$0.20	$0.19	$0.89	$0.07	**$5.30**
Year 12	$4.02	$0.21	$0.19	$0.91	$0.08	**$5.40**
Year 13	$4.10	$0.21	$0.20	$0.92	$0.08	**$5.51**
Year 14	$4.18	$0.22	$0.20	$0.94	$0.08	**$5.62**
Year 15	$4.27	$0.22	$0.20	$0.96	$0.08	**$5.73**
Year 16	$4.35	$0.22	$0.21	$0.98	$0.08	**$5.85**
Year 17	$4.44	$0.23	$0.21	$1.00	$0.08	**$5.96**
Year 18	$4.53	$0.23	$0.22	$1.02	$0.09	**$6.08**
Year 19	$4.62	$0.24	$0.22	$1.04	$0.09	**$6.20**
Year 20	$4.53	$0.23	$0.22	$1.06	$0.09	**$6.14**
20-Year Total	**$78.40**	**$4.03**	**$3.74**	**$17.70**	**$1.49**	**$105.35**
20-Year NPV	**$39.80**	**$2.05**	**$1.90**	**$8.98**	**$0.75**	**$53.47**

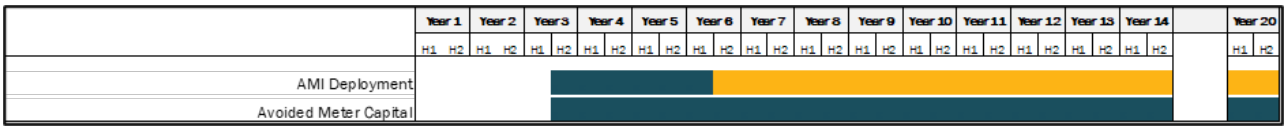
	Benefit Realization Targets ($M)			
	Avoided Annual Meter Reading Labor Cost Benefit	Avoided Annual Meter Reading Non-Labor O&M Cost Benefit	Avoided Annual Meter Reading Vehicle Cost Benefit	Total Benefit
Year 1	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.00	$0.00	$0.00	**$0.00**
Year 4	$0.28	$0.32	$0.00	**$0.60**
Year 5	$0.57	$0.66	$0.01	**$1.24**
Year 6	$0.73	$0.87	$0.02	**$1.61**
Year 7	$0.89	$1.09	$0.02	**$2.00**
Year 8	$1.21	$1.53	$0.02	**$2.77**
Year 9	$1.23	$1.61	$0.02	**$2.87**
Year 10	$1.26	$1.69	$0.02	**$2.98**
Year 11	$1.28	$1.78	$0.02	**$3.09**
Year 12	$1.31	$1.87	$0.02	**$3.20**
Year 13	$1.34	$1.96	$0.02	**$3.32**
Year 14	$1.36	$2.06	$0.03	**$3.45**
Year 15	$1.39	$2.17	$0.03	**$3.58**
Year 16	$1.42	$2.28	$0.03	**$3.72**
Year 17	$1.45	$2.39	$0.03	**$3.86**
Year 18	$1.48	$2.51	$0.03	**$4.01**
Year 19	$1.51	$2.64	$0.03	**$4.17**
Year 20	$1.54	$2.77	$0.03	**$4.34**
20-Year Total	**$20.23**	**$30.20**	**$0.38**	**$50.82**
20-Year NPV	**$8.64**	**$12.39**	**$0.16**	**$21.19**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization					
	Number of Meters Read via AMI Monthly	Percent of Meters Read via AMI Monthly	Actual Monthly Capital Costs to Support AMR Meter Reading Activities ($M/Month)	Actual Monthly Expenses to Support AMR Meter Reading Activities ($M/Month)	Actual Monthly Capital Costs to Support AMI Meter Reading Activities ($M/Month)	Actual Monthly Expenses to Support AMI Meter Reading Activities ($M/Month)	Reduction In Miles Driven (miles)	Reduction in Carbon from Reduced Miles Driven (metric tons)
Year 1	0	0%	$0.04	$0.00	$0.00	$0.00	0	0
Year 2	0	0%	$0.04	$0.00	$0.00	$0.00	0	0
Year 3	0	0%	$0.04	$0.00	$0.00	$0.00	0	0
Year 4	740,661	50%	$0.05	$0.00	$0.00	$0.00	73,971	29
Year 5	1,228,013	83%	$0.05	$0.00	$0.00	$0.00	123,300	48
Year 6	1,482,737	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 7	1,504,979	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 8	1,527,553	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 9	1,550,467	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 10	1,573,724	100%	$0.05	$0.00	$0.00	$0.00	147,957	58

	Benefit Availability		Benefit Realization					
	Number of Meters Read via AMI Monthly	Percent of Meters Read via AMI Monthly	Actual Monthly Capital Costs to Support AMR Meter Reading Activities ($M/Month)	Actual Monthly Expenses to Support AMR Meter Reading Activities ($M/Month)	Actual Monthly Capital Costs to Support AMI Meter Reading Activities ($M/Month)	Actual Monthly Expenses to Support AMI Meter Reading Activities ($M/Month)	Reduction In Miles Driven (miles)	Reduction in Carbon from Reduced Miles Driven (metric tons)
Year 11	1,597,329	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 12	1,621,289	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 13	1,645,609	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 14	1,670,293	100%	$0.05	$0.00	$0.00	$0.00	147,957	58
Year 15	1,695,347	100%	$0.06	$0.00	$0.00	$0.00	147,957	58
Year 16	1,720,777	100%	$0.06	$0.00	$0.00	$0.00	147,957	58
Year 17	1,746,589	100%	$0.06	$0.00	$0.00	$0.00	147,957	58
Year 18	1,772,788	100%	$0.06	$0.00	$0.00	$0.00	147,957	58
Year 19	1,799,380	100%	$0.06	$0.00	$0.00	$0.00	147,957	58
Year 20	1,826,370	100%	$0.06	$0.00	$0.00	$0.00	147,957	58

(ii) <u>Avoided Meter Capital</u>



a. Description

The Company replaces around 75,000 AMR meters annually due to damage and the meters reaching their end of useful life. If not for AMI, the Company would continue to replace around 75,000 AMR meters annually over the next 20 years. By deploying AMI, the annual material and labor cost to replace these meters is avoided. This presents a significant benefit to customers, as it eliminates the need for both the capital expenditure on new AMR meters and the associated labor costs. However, the offsetting component of this benefit is AMI deployment and ongoing replacement of damaged AMI meters as well as the unrecovered AMR costs that are accounted for in Section D.1. – Meter. This benefit is considered an avoided cost, meaning that it represents labor, equipment, or system costs that would be incurred over the normal course of business without AMI meters deployed.

Separately, as part of the Company's contract with its meter vendor for the Massachusetts's AMI deployment, the meter vendor will grant the Company a credit for hybrid AMR/AMI "bridge" meters that are replaced with an AMI meter during deployment only. The credits can be applied toward future AMI meter purchases. The Company's current 436,246 bridge meters plus any new bridge meters installed ahead of AMI deployment in Connecticut are eligible to receive the credit towards AMI purchases, up to the contractual cap on the total credit. This acts as a benefit to offset AMI meter costs, while ensuring that all customers have equitable access to AMI benefits. The bridge meter reading credit is a benefit that reduces the cost to deploy AMI via procurement-related value.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

The avoided meter capital cost calculation assumes current AMR and bridge meters would be replaced with a similar AMR or bridge meter as they reach the end of the 20-year useful life. The annual benefit of the AMI deployment is based on the number of AMR or bridge meters that would be replaced per year by customer class, multiplied by the per meter material and labor cost, which ranges in price dependent on the customer class. The bridge meter credit multiplies the number of bridge meters replaced each year by the credit value. The number of bridge meters will grow to more than the current amount of 436,246 by when AMI deployment begins in mid-Year 3. The credit takes 3 months to process after the bridge meter is replaced with an AMI meter.

Annual Benefit Calculations:

Business As Usual Avoided Meter Capital Material Calculation:					
Annual Residential AMR/Bridge Meter Replacements (#)	X	Residential AMR/Bridge Meter Cost ($)	X	Inflation (%)	
65,934		Confidential		2%	
Annual Small C&I AMR/Bridge Meter Replacements (#)	X	Small C&I AMR/Bridge Meter Cost ($)	X	Inflation (%)	
9,193		Confidential		2%	
Annual Large C&I AMR/Bridge Meter Replacements (#)	X	Large C&I AMR/Bridge Meter Cost ($)	X	Inflation (%)	
250		Confidential		2%	

Post-AMI Deployment Avoided Meter Capital Material Calculation:							
Annual Residential AMR/Bridge Meter Replacements (#)	X	Residential AMR/Bridge Meter Cost ($)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)	
65,934		Confidential		2%		17%-100%	
Annual Small C&I AMR/Bridge Meter Replacements (#)	X	Small C&I AMR/Bridge Meter Cost ($)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)	
9,193		Confidential		2%		17%-100%	
Annual Large C&I AMR/Bridge Meter Replacements (#)	X	Large C&I AMR/Bridge Meter Cost ($)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)	
250		Confidential		2%		17%-100%	

Business As Usual Avoided Meter Capital Labor Calculation:						
Annual Residential AMR/Bridge Meter Replacements (#)	X	Residential AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)
65,934		$55.74		48%		2%

Annual Small C&I AMR/Bridge Meter Replacements (#)	X	Small C&I AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)	
9,193		$55.74		48%		2%	
Annual Large C&I AMR/Bridge Meter Replacements (#)	X	Large C&I AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)	
250		$55.74		48%		2%	

Post-AMI Deployment Avoided Meter Capital Labor Calculation:								
Annual Residential AMR/Bridge Meter Replacements (#)	X	Residential AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)
65,934		$55.74		48%		2%		17%-100%
Annual Small C&I AMR/Bridge Meter Replacements (#)	X	Small C&I AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)
9,193		$55.74		48%		2%		17%-100%
Annual Large C&I AMR/Bridge Meter Replacements (#)	X	Large C&I AMR/Bridge Meter Replacement Labor Cost ($)	X	Labor Overhead (%)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)
250		$55.74		48%		2%		17%-100%

Post-AMI Deployment Bridge Meter Credit Calculation:				
Number of Bridge Meters (#)	X	Meter Growth (%)	X	Credit per Bridge Meter ($)
436,246		1.5%		Confidential

Avoided Meter Capital List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual Residential AMR/Bridge Meter Replacements (#)	65,934	Average 20-year forecasted meter replacements based on meter age and expected end of life	A higher or lower amount of AMR/Bridge meters could need to be replaced each year
Annual Small C&I AMR/Bridge Meter Replacements (#)	9,193		
Annual Large C&I AMR/Bridge Meter Replacements (#)	250		
Residential AMR/Bridge Meter Cost ($)	Confidential	Current pricing with vendor	The price of AMR/Bridge meters could be higher or lower in the future, and increase higher than 2% inflation
Small C&I AMR/Bridge Meter Cost ($)	Confidential		
Large C&I AMR/Bridge Meter Cost ($)	Confidential		

Avoided Meter Capital List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Residential AMR/Bridge Meter Replacement Labor Cost ($)	$55.74	Company cost data	Labor costs may exceed 2% inflation
Small C&I AMR/Bridge Meter Replacement Labor Cost ($)	$55.74		
Large C&I AMR/Bridge Meter Replacement Labor Cost ($)	$55.74		
Number of Bridge Meters (#)	436,246	Company data, assumes current population of bridge meters will grow at 1.5% until AMI deployment begins	A higher or lower amount of bridge meters could be replaced each year until AMI deployment begins, lowering or raising the credit
Credit per Bridge Meter ($)	Confidential	Contract with AMI meter vendor	Estimated pricing terms are based on previously negotiated vendor contract
Labor Overhead (%)	48%	Company cost data	Actual future company overheads may be higher or lower than this value
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meter growth could be higher or lower than 1.5%, depending on a number of factors
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)			
	Baseline Meter Capital Material Costs	Baseline Meter Capital Labor Costs	Baseline Total	Avoided Meter Capital Material Costs	Avoided Meter Capital Labor Costs	Bridge Meter Return Credit	Benefit Total
Year 1	$9.08	$6.31	**$15.39**	$0.00	$0.00	*	**$0.00**
Year 2	$9.27	$6.44	**$15.71**	$0.00	$0.00	*	**$0.00**
Year 3	$9.45	$6.57	**$16.02**	$1.57	$1.09	*	**$4.61**
Year 4	$9.63	$6.69	**$16.32**	$4.81	$3.35	*	**$15.92**
Year 5	$9.91	$6.89	**$16.81**	$8.26	$5.74	*	**$21.76**
Year 6	$10.11	$7.03	**$17.14**	$10.11	$7.03	*	**$22.96**
Year 7	$10.31	$7.17	**$17.48**	$10.31	$7.17	*	**$17.48**
Year 8	$10.52	$7.31	**$17.83**	$10.52	$7.31	*	**$17.83**
Year 9	$10.73	$7.46	**$18.19**	$10.73	$7.46	*	**$18.19**
Year 10	$10.95	$7.61	**$18.55**	$10.95	$7.61	*	**$18.55**
Year 11	$11.16	$7.76	**$18.93**	$11.16	$7.76	*	**$18.93**
Year 12	$11.39	$7.92	**$19.30**	$11.39	$7.92	*	**$19.30**
Year 13	$11.62	$8.07	**$19.69**	$11.62	$8.07	*	**$19.69**
Year 14	$11.85	$8.24	**$20.08**	$11.85	$8.24	*	**$20.08**
Year 15	$12.08	$8.40	**$20.49**	$12.08	$8.40	*	**$20.49**
Year 16	$12.33	$8.57	**$20.90**	$12.33	$8.57	*	**$20.90**
Year 17	$12.57	$8.74	**$21.31**	$12.57	$8.74	*	**$21.31**
Year 18	$12.71	$8.83	**$21.54**	$12.71	$8.83	*	**$21.54**
Year 19	$12.96	$9.01	**$21.97**	$12.96	$9.01	*	**$21.97**
Year 20	$13.22	$9.19	**$22.41**	$13.22	$9.19	*	**$22.41**
20-Year Total	**$221.85**	**$154.22**	**$376.06**	**$189.16**	**$131.49**	*	**$343.93**
20-Year NPV	**$112.46**	**$78.18**	**$190.64**	**$84.60**	**$58.81**	*	**$160.33**

* Confidential utility figures

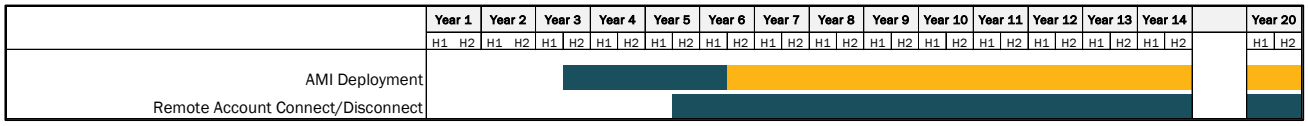
d. Data to Track the Availability of the Benefit

	Benefit Availability	Benefit Realization	
	Avoided Cost of Replacement AMR Meters and Associated Labor ($M)	Avoided Number of AMR Meters Replaced at or Exceeding Useful Life (#)	Percent of AMR Meters Replaced at or Exceeding Useful Life (%)
Year 1	$0.00	0	0%
Year 2	$0.00	0	0%
Year 3	$4.61	12,497	17%
Year 4	$15.92	37,452	50%
Year 5	$21.76	63,011	83%
Year 6	$22.96	75,612	100%
Year 7	$17.48	75,612	100%
Year 8	$17.83	75,612	100%
Year 9	$18.19	75,612	100%
Year 10	$18.55	75,612	100%

	Benefit Availability	Benefit Realization	
	Avoided Cost of Replacement AMR Meters and Associated Labor ($M)	Avoided Number of AMR Meters Replaced at or Exceeding Useful Life (#)	Percent of AMR Meters Replaced at or Exceeding Useful Life (%)
Year 11	$18.93	75,612	100%
Year 12	$19.30	75,612	100%
Year 13	$19.69	75,612	100%
Year 14	$20.08	75,612	100%
Year 15	$20.49	75,612	100%
Year 16	$20.90	75,612	100%
Year 17	$21.31	75,612	100%
Year 18	$21.54	74,912	100%
Year 19	$21.97	74,912	100%
Year 20	$22.41	74,912	100%

B.2 AUTOMATE SERVICE ORDERS

(i) Remote Account Connect/Disconnect



a. Description

The Company's AMI meter deployment plan includes the capability to perform remote turn-on and turn-off service, which can be initiated via the headend system ("HES") and eliminates the need for a meter services truck roll. The service switch can be activated remotely through the wireless communications network at any time from specific Company systems, (e.g., initiated from the CIS and automated through the MDMS and HES, in compliance with all regulatory guidelines). This functionality will nearly eliminate the need for physical visits to customer premises for turn-on and turn-off service requests. Customers will have the option to request service shut-off or turn-on through an online self-service, meaning quick-response for automated completions 24 hours a day, seven days a week. Customers will also be able to schedule their start- and stop-service orders for specific dates and times.

The majority of the original mechanical AMR meters were installed between 2000 and 2003. In 2016, the company moved to a solid-state AMR meter and selected the hybrid bridge meter as the appropriate standard meter. The Company currently has 436,246 hybrid bridge meters with the capability to turn on and off the service with a 'curbside' hand-held device within 200 yards.
A benefit of bridge technology is to have a meter that can be used on the AMR network and eventually be switched over to work on an AMI network at a future date. By the time AMI was approved for deployment in Massachusetts, a new AMI 2.0 meter was available that offered additional customer and company benefits beyond the original AMI 1.0 meters. The company decided that the AMI 2.0

solution was the appropriate technology to pursue. Unfortunately, the hybrid bridge meters are only capable of switching to an AMI 1.0 network and would not be able to work as AMI meters on an AMI 2.0 network. Additionally, hybrid bridge meters do not have the same AMI features as the AMI 2.0 meter, that functionality gap would create two classes of AMI customers. In order to avoid creating any "second-class AMI citizens," where some customers are not afforded the same benefits as other customers simply based on when their meter was installed, the company has taken the position that hybrid bridge meters should be replaced with the AMI 2.0 meter proposed in this BCA.

This AMI 2.0 remote connect/disconnect ("RCD") capability will produce benefits in the form of avoided labor and equipment costs. Remote turn-on and turn-off functionality also offers other non-quantifiable benefits, including improved safety. Technician exposure to hazards on customer premises is reduced substantially. Another proven use case is the ability for the electric utility to shut off electric service when a methane or gas leak is either suspected or detected at the service location.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

To calculate the benefits related RCD, the Company analyzed current and post-AMI deployment operating costs and maintenance, including labor, non-labor, and contractor costs. A key factor in this area is that resources perform both electric and gas service disconnections and reconnections within one team. The combined gas and electric revenue assurance teams currently has 33 staff, which will experience a gradual attrition down to 7 staff post-AMI deployment, beginning midway through AMI deployment in Year 5 and until reaching steady state 1 year after the meter deployment is completed in mid-Year 7. This is a reduction of 26 FTEs.

Separately, the field operations team currently has 50 FTEs, which will not experience any reduction in FTEs post-AMI and are not represented in the BCA. Post-AMI, avoided field trips associated with RCD credit orders are assumed to be offset by incremental truck rolls needed to address RCD failures, and the affected field resources are still expected to support other operational responsibilities. As a result, no net field operations savings or staffing reduction is reflected for this use case in the BCA.

From a timing perspective, the Company plans to start using AMI remote capabilities to perform all service connections and disconnections for customers moving out on AMI meters no later than 1 year after the AMI meter deployment has begun. The Company plans to utilize the AMI remote disconnection capability for non-payment starting no later than 1 year after the AMI meter deployment has completed. The Company notes that the reduction in truck rolls will help reduce carbon emissions; however, those benefits were not quantified for inclusion in the BCA calculations.

Annual Benefit Calculations:

Business As Usual Remote Account Connect/Disconnect Loaded Labor Calculation:		
Average Annual BAU Field Operations Loaded Dispatcher Labor Costs ($)	X	Inflation (%)
$6,151,063		2%

Post-AMI Deployment Remote Account Connect/Disconnect Loaded Labor Savings Calculation:				
Average Annual BAU Field Operations Loaded Dispatcher Labor Costs ($)	–	Average Annual Post-AMI Deployment Field Operations Loaded Dispatcher Labor Costs ($)	X	Inflation (%)
$6,151,063		$2,972,187		2%

Remote Account Connect/Disconnect List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Average Annual BAU Field Operations Loaded Labor Costs ($)	$6,151,063	33 staff consisting of dispatchers, supervisors, and contractors	Annual BAU costs may increase faster or slower than 2% inflation and the amount of staff required under BAU may increase or decrease depending on meter growth and geography considerations of new meters
Average Annual Post-AMI Deployment Field Operations Loaded Labor Costs ($)	$2,972,187	Gradual attrition from BAU after RCD go-live no later than 1 year after AMI deployment begins, assuming AMI deployment begins in mid-Year 3 and is complete in mid-Year 6. Reduces to 7 staff.	Post-AMI deployment, meter mechanics will handle RCD fails and opt-outs. Contractors are based on SONP job and FTE calculation includes an estimate to complete the study. These activities may require more or less staff than is projected
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Remote Connect / Disconnect Labor Costs	Avoided Remote Connect / Disconnect Labor Costs
Year 1	$5.06	$0.00
Year 2	$5.16	$0.00
Year 3	$5.27	$0.00

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Remote Connect / Disconnect Labor Costs	Avoided Remote Connect / Disconnect Labor Costs
Year 4	$5.37	$0.00
Year 5	$5.48	$0.71
Year 6	$5.59	$2.18
Year 7	$5.70	$3.80
Year 8	$5.82	$4.83
Year 9	$5.93	$4.92
Year 10	$6.05	$5.02
Year 11	$6.17	$5.12
Year 12	$6.30	$5.22
Year 13	$6.42	$5.33
Year 14	$6.55	$5.44
Year 15	$6.68	$5.54
Year 16	$6.81	$5.65
Year 17	$6.95	$5.77
Year 18	$7.09	$5.88
Year 19	$7.23	$6.00
Year 20	$7.38	$6.12
20-Year Total	**$123.02**	**$77.55**
20-Year NPV	**$62.38**	**$32.17**

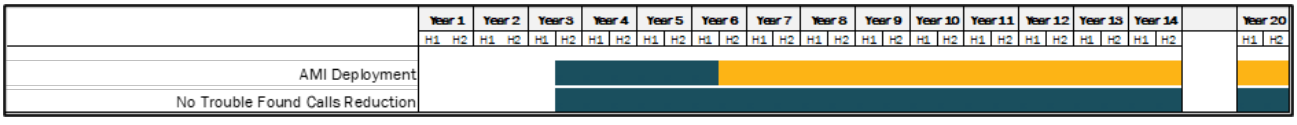
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability	
	Number of Customer Accounts Available for Remote Connect/ Disconnect (#)	Percent of Customer Accounts Available for Remote Connect/ Disconnect (%)
Year 1	0	0%
Year 2	0	0%
Year 3	0	0%
Year 4	0	0%
Year 5	1,023,365	83%
Year 6	1,482,737	100%
Year 7	1,504,979	100%
Year 8	1,527,553	100%
Year 9	1,550,467	100%
Year 10	1,573,724	100%
Year 11	1,597,329	100%
Year 12	1,621,289	100%
Year 13	1,645,609	100%
Year 14	1,670,293	100%
Year 15	1,695,347	100%
Year 16	1,720,777	100%
Year 17	1,746,589	100%
Year 18	1,772,788	100%

	Benefit Availability	
	Number of Customer Accounts Available for Remote Connect/ Disconnect (#)	Percent of Customer Accounts Available for Remote Connect/ Disconnect (%)
Year 19	1,799,380	100%
Year 20	1,826,370	100%

	Benefits Realization					
	Monthly Average Number of BAU Manual Connects / Disconnects (#)	Monthly Average Number of BAU Manual Connects / Disconnects (%)	Monthly Average Number of Post-AMI Deployment Potential Manual and Remote Connects / Disconnects (#)	Monthly Average Number of Post-AMI Deployment Potential Remote Connects / Disconnects (%)	Difference in Number of Post-AMI Deployment Connects / Disconnects Compared to Historical Baseline (#)	Avoided Monthly Labor, Vehicle and Contractor Costs ($M)
Year 1	0	0%	0	0%	0	$0.00
Year 2	0	0%	0	0%	0	$0.00
Year 3	0	0%	0	0%	0	$0.00
Year 4	0	0%	0	0%	0	$0.00
Year 5	6,101	83%	15,516	83%	9,414	$0.06
Year 6	7,321	100%	18,618	100%	11,297	$0.18
Year 7	7,321	100%	18,618	100%	11,297	$0.32
Year 8	7,321	100%	18,618	100%	11,297	$0.40
Year 9	7,321	100%	18,618	100%	11,297	$0.41
Year 10	7,321	100%	18,618	100%	11,297	$0.42
Year 11	7,321	100%	18,618	100%	11,297	$0.43
Year 12	7,321	100%	18,618	100%	11,297	$0.44
Year 13	7,321	100%	18,618	100%	11,297	$0.44
Year 14	7,321	100%	18,618	100%	11,297	$0.45
Year 15	7,321	100%	18,618	100%	11,297	$0.46
Year 16	7,321	100%	18,618	100%	11,297	$0.47
Year 17	7,321	100%	18,618	100%	11,297	$0.48
Year 18	7,321	100%	18,618	100%	11,297	$0.49
Year 19	7,321	100%	18,618	100%	11,297	$0.50
Year 20	7,321	100%	18,618	100%	11,297	$0.51

(ii) <u>No Trouble Found (NTF) Calls Reduction</u>



a. Description

Without AMI, the Company is dependent on customer calls to detect and respond to an outage. In many cases, customer calls are for a disruption at a single premise. Sometimes, the crews find no

trouble with the electric service, typically indicating a problem on the customer-side equipment inside their home/business, but Eversource still incurs the costs for the crews to be dispatched to assess the situation. These calls are ultimately resolved as "no trouble found" ("NTF") and are closed by the operator without additional action by the Company.

With the availability of an AMI system, operators can conduct remote diagnostics without dispatching a crew, including reading the voltage on the high side (i.e., grid-side) and low side (i.e., customer premise side) of the service switch. When a customer reports voltage or other service issue, system operators can immediately 'ping' the AMI meter to confirm the outage. The operator also has ready access to historical event flags, granular usage data, and other useful metrics for the associated meter, providing actionable insights into the cause if there is a confirmed outage. If the reported issue is not caused by a problem on the grid-side, the meter may be able to provide insights with respect to possible issues detected on the load, or customer, side of the meter.

These same AMI capabilities—real-time meter status, outage confirmation, and remote diagnostics—also underpin the Company's improved restoration benefits in both significant storm and blue sky conditions. In those sections, the same underlying functionality is applied to system restoration and crew prioritization; here, it is applied at the individual-premise level to avoid unnecessary dispatches and reduce NTF-related truck rolls. With these capabilities, AMI will significantly reduce the number of NTF-related truck rolls. The Company's ability to provide immediate access to information and analysis and provide actionable insights into the customer's electrical service is also expected to support improvements in customer satisfaction. This capability helps the company reduce the costs of labor and equipment caused by unnecessary truck rolls.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

The Company expects AMI implementation to reduce the number of NTF calls that require a truck roll by 90%. The total number of estimated NTF calls is based on the historical event data captured in the last five years in the Company's OMS database. The yearly total of estimated NTF events is multiplied by the labor rate and overhead per NTF to determine the labor costs, and to the cost per mile of the expected reduction in vehicle miles traveled to determine the vehicle costs avoided. This will enable the Company to utilize the existing workforce to perform other capital, operation, or maintenance activities for the time that would otherwise be spent investigating the NTF event.

Annual Benefit Calculations:

Business As Usual No Trouble Found Calls Labor Calculation:						
Annual Number of No Trouble Found Calls (#)	X	Troubleshooter Labor Rate ($)	X	Inflation (%)	X	Meter Growth (%)
3,536		$128.21		2%		2%

Post-AMI Deployment No Trouble Found Calls Labor Savings Calculation:											
Annual Number of No Trouble Found Calls (#)	X	Reduction in No Trouble Found Calls Through AMI (%)	X	Troubleshooter Loaded Labor Rate ($)	X	Inflation (%)	X	Meter Growth (%)	X	Annual AMI Meters Deployed (%)
3,536		90%		$128.21		2%		2%		17%-100%

Business As Usual No Trouble Found Calls Vehicle Calculation:								
Annual Number of No Trouble Found Calls (#)	X	Miles Driven per No Trouble Found Call (#)	X	Cost per Mile Driven ($/Mile)	X	Inflation (%)	X	Meter Growth (%)
3,536		25		$1.27		2%		1.5%

AMI Deployment No Trouble Found Calls Vehicle Savings Calculation:											
Annual Number of No Trouble Found Calls (#)	X	Reduction in No Trouble Found Calls Through AMI (%)	X	Miles Driven per No Trouble Found Call (#)	X	Cost per Mile Driven ($/Mile)	X	Inflation (%)	X	Meter Growth (%)	X	Annual AMI Meters Deployed (%)
3,536		90%		25		$1.27		2%		1.5%		17%-100%

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline NTF Labor	Baseline NTF Vehicle Costs	Baseline Total	NTF Labor Avoided Cost Benefit	NTF Vehicle Avoided Cost Benefit	Benefit Total
Year 1	$0.46	$0.11	**$0.58**	$0.00	$0.00	**$0.00**
Year 2	$0.47	$0.12	**$0.59**	$0.00	$0.00	**$0.00**
Year 3	$0.48	$0.12	**$0.60**	$0.08	$0.02	**$0.09**
Year 4	$0.49	$0.12	**$0.61**	$0.23	$0.06	**$0.29**
Year 5	$0.50	$0.12	**$0.62**	$0.40	$0.10	**$0.50**
Year 6	$0.51	$0.13	**$0.64**	$0.50	$0.12	**$0.63**
Year 7	$0.52	$0.13	**$0.65**	$0.52	$0.13	**$0.65**
Year 8	$0.53	$0.13	**$0.66**	$0.54	$0.13	**$0.67**
Year 9	$0.54	$0.13	**$0.68**	$0.56	$0.14	**$0.70**
Year 10	$0.55	$0.14	**$0.69**	$0.58	$0.14	**$0.72**
Year 11	$0.56	$0.14	**$0.70**	$0.60	$0.15	**$0.75**
Year 12	$0.57	$0.14	**$0.72**	$0.62	$0.15	**$0.77**
Year 13	$0.59	$0.15	**$0.73**	$0.64	$0.16	**$0.80**
Year 14	$0.60	$0.15	**$0.75**	$0.66	$0.16	**$0.83**
Year 15	$0.61	$0.15	**$0.76**	$0.69	$0.17	**$0.86**
Year 16	$0.62	$0.15	**$0.78**	$0.71	$0.18	**$0.89**
Year 17	$0.63	$0.16	**$0.79**	$0.74	$0.18	**$0.92**
Year 18	$0.65	$0.16	**$0.81**	$0.76	$0.19	**$0.95**

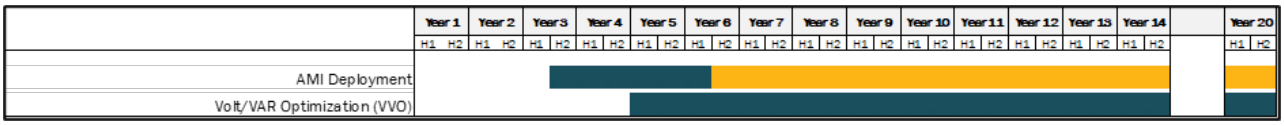
	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline NTF Labor	Baseline NTF Vehicle Costs	Baseline Total	NTF Labor Avoided Cost Benefit	NTF Vehicle Avoided Cost Benefit	Benefit Total
Year 19	$0.66	$0.16	**$0.82**	$0.79	$0.20	**$0.98**
Year 20	$0.67	$0.17	**$0.84**	$0.82	$0.20	**$1.02**
20-Year Total	**$11.24**	**$2.78**	**$14.02**	**$10.43**	**$2.58**	**$13.01**
20-Year NPV	**$5.70**	**$1.41**	**$7.11**	**$4.56**	**$1.13**	**$5.68**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization				
	Number of Customers with NTF Availability (#)	Percent of Customers with NTF Availability (%)	Pre-AMI Baseline Monthly Historical Number of NTF (#)	Monthly Number of NTF & Truck Rolls Reduced (#/Month)	Percent of NTF & Truck Rolls Reduced (%)	Labor Rate Avoided for Reduced NTF Truck Rolls ($M)	Vehicle Charges Avoided for Reduced NTF Truck Rolls ($M)
Year 1	0	0%	299	0	0%	$0.00	$0.00
Year 2	0	0%	304	0	0%	$0.00	$0.00
Year 3	253,767	17%	308	46	15%	$0.08	$0.02
Year 4	740,661	50%	313	141	45%	$0.23	$0.06
Year 5	1,228,013	83%	317	238	75%	$0.40	$0.10
Year 6	1,482,737	100%	322	290	90%	$0.50	$0.12
Year 7	1,504,979	100%	327	294	90%	$0.52	$0.13
Year 8	1,527,553	100%	332	299	90%	$0.54	$0.13
Year 9	1,550,467	100%	337	303	90%	$0.56	$0.14
Year 10	1,573,724	100%	342	308	90%	$0.58	$0.14
Year 11	1,597,329	100%	347	312	90%	$0.60	$0.15
Year 12	1,621,289	100%	352	317	90%	$0.62	$0.15
Year 13	1,645,609	100%	358	322	90%	$0.64	$0.16
Year 14	1,670,293	100%	363	327	90%	$0.66	$0.16
Year 15	1,695,347	100%	368	332	90%	$0.69	$0.17
Year 16	1,720,777	100%	374	337	90%	$0.71	$0.18
Year 17	1,746,589	100%	380	342	90%	$0.74	$0.18
Year 18	1,772,788	100%	385	347	90%	$0.76	$0.19
Year 19	1,799,380	100%	391	352	90%	$0.79	$0.20
Year 20	1,826,370	100%	397	357	90%	$0.82	$0.20

B.3 ENERGY AND DEMAND REDUCTION

(i) Volt/Var Optimization (VVO)



a. Description

The concept of reducing service voltage to customers to reduce line losses and energy consumption is not new. Utilities have long recognized the relationship between a reduction in a customer's energy usage and a decrease in voltage on the feeder.

For years, the Company has implemented a more basic form of voltage reduction by lowering voltage at the substation bus to a level that was expected to keep voltage within the required tolerance range for all customers on the associated feeders and manually changing line regulator and capacitor bank settings. This approach relied on the assumption that the customers at the end of a feeder would experience voltage levels within the lower end of the acceptable range. The tradeoff in this approach is that the customers closer to the substation will end up with a voltage level that is towards the higher end of the acceptable voltage range.

This approach relied on calculations and models to determine the appropriate device settings to produce the desired results under most conditions. Without real-time sensing, communication and control of line regulators and capacitors, it proved difficult to achieve meaningful levels of savings while ensuring reliable, high-quality service to customers. As the electric power grid becomes more complex over time with distribution automation and increased penetration of intermittent solar generation and other DER deployments, the limitations of legacy voltage management techniques are increasingly apparent. Advances in technology have expanded valuable opportunities to improve system efficiency by optimizing power flow. These VVO capabilities can reduce energy consumption, optimize demand, and manage VAR flow to maintain adequate voltage. In particular, the ability to collect voltage data at all meter points along the feeder in real-time, process the data using VVO software, and immediately send commands to substation transformers, line regulators, and capacitor banks is a major advancement from the prior techniques. With visibility into real-time feeder conditions and remote control of devices, a VVO system will reduce the potential for customers to experience low voltage or voltage flicker. In addition to these power quality enhancements, VVO can help defer distribution capacity investments by reducing peak demand on the system.

Advanced voltage management is a well-established industry standard that utilities have been implementing for over a decade. 26 of the 99 Smart Grid Investment Grant projects administered by the U.S. Department of Energy ("DOE") under the American Recovery and Reinvestment Act ("ARRA") included voltage management, demonstrating broad, early adoption across the industry as far back as 2009. Since then, these techniques have become routine operational practices, with dozens of utilities, including Ameren, PG&E, Con Edison, FP&L, and others, deploying and operating volt/VAR optimization and conservation voltage reduction as standard distribution system tools. These voltage management

practices are commonly integrated with utilities' AMI systems, as described in the DOE's 2019 report "Leveraging AMI Networks and Data".[5]

Implementation of a modern VVO system requires three categories of investment. First, substation transformer load tap changers, voltage regulators, and capacitor banks must be equipped with two-way communication and control capability. Existing voltage regulators and capacitor banks are typically controlled via a one-way paging system that is obsolete and will not meet the requirements of a modern VVO solution, Replacing the communications infrastructure to enable two-way communication between these devices and the Company's control center will be required. Second, centralized software is required to analyze voltage and VAR data to determine the optimal system configuration and send control signals to field devices to implement the recommended scheme. This software capability must be integrated into the Company's system operations center. Third, line sensors are required to measure voltage at the feeder head, at the end of the distribution circuit, and at numerous points in-between. Without AMI, the Company would need to deploy multiple stand-alone line sensors at various points on the primary distribution feeder. This deployment would also require costly end-of-line sensors to round out the necessary situational awareness required to implement an effective VVO solution. This associated avoided sensor cost benefit provided by AMI is detailed in Section B.4.i. – Asset Optimization.

The availability of meter-level voltage monitoring enabled by AMI increases the efficiency of deploying VVO. AMI greatly reduces the need for line sensors on the primary system to support VVO calculations, and by collecting data at over one million points on the system, AMI will provide vastly more information to the VVO software relative to line sensors alone. This level of system visibility will significantly improve the accuracy and effectiveness of VVO optimization algorithms.

Currently, Eversource does not have VVO capabilities in Connecticut. The Company expects to begin deploying the necessary infrastructure and building the capabilities and analytics required to support a VVO solution that will be integrated with the proposed AMI deployment. By implementing these capabilities in tandem with AMI, the full, optimized energy and demand savings achievable through AMI-enhanced VVO will be available to customers. This benefit is considered a customer savings benefit, meaning that the value is realized directly by customers, both through reduced billing costs and improved reliability. Benefits associated with VVO include are reductions in peak load and energy consumption, which customers will experience as lower supply and distribution costs over time. Costs to implement VVO capabilities are also included in the BCA Report, in Section D.6.i – VVO Enablement

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

[5] U.S. Department of Energy. (2019). Leveraging AMI Networks and Data. Advanced Grid Research. https://www.energy.gov/sites/default/files/2024-02/01-03-2019_doe-voe-leveraging-ami-networks-and-data-report_508_0.pdf

b. Benefit Calculation Methodology

Customers will gradually begin receiving partial VVO benefit realization in Year 5 and will receive full VVO benefit by Year 10 as more energy and demand enabling capacitor, regulator, and LTC equipment is implemented across the service area over six years. An AMI-enabled VVO scheme includes both energy conservation benefits and demand reduction benefits. Given that some feeders on the Eversource system are not likely to benefit from VVO, the Company estimates 65% of feeders will be included in the VVO program. The avoided energy and demand on these circuits is multiplied by energy and demand rates from the 2024 Avoided Energy Supply Cost ("AESC") Study to determine a dollar amount associated with these energy and demand savings.

Section B.4.i. – Asset Optimization details the benefits of avoided cellular charges and avoided line-sensor capital associated with the AMI supported VVO program. The ultimate value of this benefit will depend on customer usage and generation patterns which are changing over time and therefore could differ substantially from the Company's projection.

Annual Benefit Calculations:

Energy Reduction

Business As Usual Energy Reduction Through VVO Calculation:							
Total System Electric Sales Volume (GWh)	X	AESC Energy Rate ($/GWh)	X	Energy Growth (%)	X	Inflation (%)	
20,251		$50,000		0.6%		2%	

Post-AMI Deployment Energy Reduction Through VVO Calculation:									
Total System Electric Sales Volume (GWh)	X	Percent of Feeders with VVO (%)	X	Energy Reduction through CVR/VVO (%)	X	AESC Energy Rate ($/GWh)	X	Annual AMI Meters Deployed (%)	X	Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X	Energy Growth (%)	X	Inflation (%)
20,251		65%		2.1%		$50,000		17%-100%		17%-100%		0.6%		2%

Demand Reduction

Business As Usual Demand Reduction Through VVO Calculation:										
System Peak Load (MW)	X	(	AESC Capacity Cost ($/MW)	+	AESC T&D Capacity Cost ($/MW)	)	X	Demand Growth (%)	X	Inflation (%)
4,518			$52,000		$69,000			0.6%		2%

Post-AMI Deployment Demand Reduction Through VVO Calculation:

System Peak Load (MW)	X Percent of Feeders with VVO (%)	X Demand Reduction through CVR/VVO (%)	X AESC Capacity Cost ($/MW)	AESC T&D + Capacity Cost ($/MW)	X Annual AMI Meters Deployed (%)	X Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X Demand Growth (%)	X Inflation (%)
4,518	65%	2.1%	$52,000	$69,000	17%-100%	17%-100%	0.6%	2%

Volt/VAR Optimization (VVO) List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Total System Electric Sales Volume (GWh)	20,251	Average of 2024 and 2025 sales volume	Meter growth is a long-term proxy for future sales (GWh) and energy sales could be greater than or less than this baseline number
Percent of Feeders with VVO (%)	65%	Company estimate based on Massachusetts data coupled with Connecticut service area dynamics	More or less feeders than 65% could need VVO capabilities
AESC Energy Rate ($/GWh)	$50,000	Connecticut value from 2024 AESC Report	Inflation is a long-term proxy for the energy rate increase and the actual future value could increase or decrease more than this amount
Energy Reduction through CVR/VVO (%)	2.1%	Company estimate	Energy reduction may deviate from assumed energy reduction potential
AESC Capacity Cost ($/MW)	$52,000	Connecticut value from 2024 AESC Report	Inflation is a long-term proxy for the energy rate increase and the actual future value could increase or decrease more than this amount
AESC T&D Capacity Cost ($/MW)	$69,000	Connecticut value from 2024 AESC Report	Inflation is a long-term proxy for the energy rate increase and the actual future value could increase or decrease more than this amount
System Peak Load (MW)	4,518	ISO-NE reporting	Meter growth is a long-term proxy for system peak load (MW) and peak load could increase faster than this rate
Demand Reduction through CVR/VVO (%)	2.1%	Company estimate	Demand reduction may deviate from assumed energy reduction potential
Benefit Realization Over 6 Years of VVO	17%-100%	17% incremental benefit per year over the 6-year	Benefit from VVO could not be evenly dispersed over 6 years or

Implementation Duration (%)		VVO implementation starting in Year Five and completing in Year Eight	take longer or shorter than 6 years to fully realize benefit
Energy Growth (%)	0.6%	Estimate based on historical and future projections	Energy use could grow greater or less than 0.6%
Demand Growth (%)	0.6%	Estimate based on historical and future projections	Demand could grow greater or less than 0.6%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Total System Energy Cost Without VVO	Baseline Total System Demand Cost Without VVO	Total Baseline Costs	Energy Reduction With VVO	Demand Reduction With VVO	Total Savings
Year 1	$1,038.68	$561.01	**$1,599.68**	$0.00	$0.00	**$0.00**
Year 2	$1,065.47	$575.71	**$1,641.19**	$0.00	$0.00	**$0.00**
Year 3	$1,092.97	$590.80	**$1,683.76**	$0.00	$0.00	**$0.00**
Year 4	$1,121.17	$606.28	**$1,727.45**	$0.00	$0.00	**$0.00**
Year 5	$1,150.09	$622.17	**$1,772.26**	$2.18	$1.18	**$3.36**
Year 6	$1,179.77	$638.48	**$1,818.24**	$5.37	$2.91	**$8.27**
Year 7	$1,210.21	$655.21	**$1,865.42**	$8.26	$4.47	**$12.73**
Year 8	$1,241.43	$672.38	**$1,913.81**	$11.30	$6.12	**$17.42**
Year 9	$1,273.46	$690.00	**$1,963.46**	$14.49	$7.85	**$22.33**
Year 10	$1,306.32	$708.09	**$2,014.40**	$17.83	$9.67	**$27.50**
Year 11	$1,340.02	$726.64	**$2,066.67**	$18.29	$9.92	**$28.21**
Year 12	$1,374.60	$745.69	**$2,120.28**	$18.76	$10.18	**$28.94**
Year 13	$1,410.06	$765.23	**$2,175.29**	$19.25	$10.45	**$29.69**
Year 14	$1,446.45	$785.28	**$2,231.73**	$19.74	$10.72	**$30.46**
Year 15	$1,483.77	$805.86	**$2,289.63**	$20.25	$11.00	**$31.25**
Year 16	$1,522.05	$826.98	**$2,349.03**	$20.78	$11.29	**$32.06**
Year 17	$1,561.32	$848.66	**$2,409.98**	$21.31	$11.58	**$32.90**
Year 18	$1,601.60	$870.90	**$2,472.50**	$21.86	$11.89	**$33.75**
Year 19	$1,642.93	$893.72	**$2,536.65**	$22.43	$12.20	**$34.63**

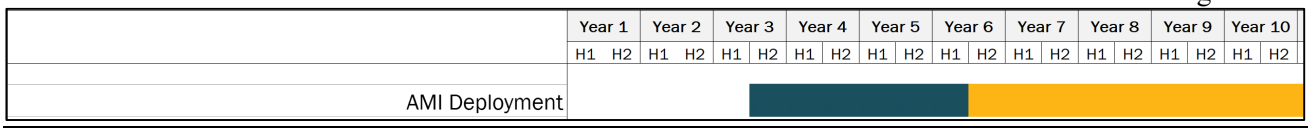
	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Total System Energy Cost Without VVO	Baseline Total System Demand Cost Without VVO	Total Baseline Costs	Energy Reduction With VVO	Demand Reduction With VVO	Total Savings
Year 20	$1,685.32	$917.14	**$2,602.46**	$23.00	$12.52	**$35.52**
20-Year Total	**$26,747.67**	**$14,506.23**	**$41,253.90**	**$265.10**	**$143.93**	**$409.03**
20-Year NPV	**$13,392.27**	**$7,256.70**	**$20,648.97**	**$106.20**	**$57.63**	**$163.83**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization		
	Number of Customers with AMI on Feeders with VVO (#)	Percentage of Customers with AMI on Feeders with VVO (%)	Monthly Energy Reduction by Feeder (MWh)	Monthly Energy Savings on Feeders with VVO ($M)	Monthly Energy Savings per Customer on Feeders with VVO ($)
Year 1	0	0%	0.00	$0.00	0
Year 2	0	0%	0.00	$0.00	0
Year 3	0	0%	0.00	$0.00	0
Year 4	0	0%	0.00	$0.00	0
Year 5	133,035	11%	21.98	$0.18	$16.39
Year 6	321,260	22%	22.11	$0.45	$16.71
Year 7	489,118	33%	22.23	$0.69	$16.89
Year 8	661,940	43%	22.36	$0.94	$17.07
Year 9	839,836	54%	22.49	$1.21	$17.25
Year 10	1,022,920	65%	22.62	$1.49	$17.43
Year 11	1,038,264	65%	22.74	$1.52	$17.62
Year 12	1,053,838	65%	22.87	$1.56	$17.80
Year 13	1,069,646	65%	23.00	$1.60	$17.99
Year 14	1,085,690	65%	23.13	$1.65	$18.19
Year 15	1,101,976	65%	23.27	$1.69	$18.38
Year 16	1,118,505	65%	23.40	$1.73	$18.57
Year 17	1,135,283	65%	23.53	$1.78	$18.77
Year 18	1,152,312	65%	23.67	$1.82	$18.97
Year 19	1,169,597	65%	23.80	$1.87	$19.17
Year 20	1,187,141	65%	23.94	$1.92	$19.38

*The Company does not currently have VVO technology in Connecticut. The Company is including high-level implementation and ongoing costs associated with VVO as part of this BCA and detailed in Section D.6.i – VVO Enablement. Once a full detailed VVO design and analysis is completed, the Company will provide these associated Benefit Availability and Benefit Realization metrics.

(ii) Carbon Reduction



a. Description

Carbon dioxide reduction is the principal environmental benefit tied to the deployment of AMI. The reduction in carbon dioxide is a result of many of the customer and Company benefits highlighted in other sections of this BCA Report. In particular, enhanced VVO is expected to lower overall energy consumption within the service territory by 2.1%, reducing the emissions from production of that energy detailed in Section B.3.i - Volt/Var Optimization (VVO).

To calculate the environmental benefit in avoided tons of CO_2, the avoided energy was multiplied by the carbon intensity of Connecticut's grid (tons CO_2/MWh), provided by the EIA's 2024 State electricity profile for Connecticut. The collective environmental impact of these offerings is a reduction in carbon dioxide emissions estimated at more than 1.5 million tons over the 20-year analysis period. For comparative purposes, 1.5 million tons of carbon emissions is equivalent to over 193,000 homes' energy use for one year. Although the environmental benefits associated with enhanced VVO and non-technical line losses are the carbon reduction drivers quantified in this BCA Report, it is reasonable to assume additional emission reductions can be realized through benefits such as reducing truck rolls for meter reading, remote account connect/disconnect, avoided connectivity survey, and no-trouble found calls.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

The quantified carbon emissions reductions are calculated based on the reduction of electricity usage and the associated reduction in emissions by avoiding the production of that electricity. Included in the calculations of the reduction in carbon emissions in the BCA is the VVO benefit, which improves the grid's operating efficiency. Additional reductions in emissions from AMI due to operational changes such as reducing truck rolls are not quantified in this BCA Report and are considered qualitative benefits.

To understand the dollar value benefit of the carbon reductions associated with these energy and demand savings, the avoided electricity was multiplied by the 20-year average 2024 AESC Non-Embedded GHG Cost factor ($/kWh).

Annual Benefit Calculations:

Carbon Reduction

Business As Usual Carbon Cost Without VVO Calculation:

Total System Electric Sales Volume (GWh)	X	Value of Carbon Avoidance ($/GWh)	X	Energy Growth (%)	X	Inflation (%)
20,251		$83,240		0.6%		2%

Post-AMI Deployment Carbon Cost Without VVO Calculation:								
Total System Electric Sales Volume (GWh)	X Percent of Feeders with VVO (%)	X Energy Reduction through CVR/VVO (%)	X Value of Carbon Avoidance ($/GWh)	X Annual AMI Meters Deployed (%)	X Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X Energy Growth (%)	X Inflation (%)
20,251	65%	2.1%	$83,240	17%-100%	17%-100%	0.6%	2%

Carbon Reduction List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Total System Electric Sales Volume (GWh)	20,251	Average of 2024 and 2025 sales volume	Meter growth is a long-term proxy for future sales (GWh) and energy sales could be greater than or less than this baseline number
Percent of Feeders with VVO (%)	65%	Company estimate based on Massachusetts data coupled with Connecticut service area dynamics	More or less feeders than 65% could need VVO capabilities
Energy Reduction through CVR/VVO (%)	2.1%	Company estimate	Energy reduction may deviate from assumed energy reduction potential
Benefit Realization Over 6 Years of VVO Implementation Duration (%)	17%-100%	17% incremental benefit per year over the 6-year VVO implementation starting in Year Five and completing in Year Eight	Benefit from VVO could not be evenly dispersed over 6 years or take longer or shorter than 6 years to fully realize benefit
Energy Growth (%)	0.6%	Estimate based on historical and future projections	Energy use could grow greater or less than 0.6%
Value of Carbon Avoidance ($/GWh)	$83,240	20-year average of "Non-Embedded GHG Costs - Social cost of GHGs" of Counterfactual No. 5 in the 2024 AESC Report	Inflation is a long-term proxy for the increase in the value of carbon avoidance. The actual future value could increase or decrease more than this amount
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

Carbon Reduction List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Carbon Cost from Total System Energy Without VVO	Carbon Benefit from Total System Energy With VVO
Year 1	$1,729.20	$0.00
Year 2	$1,773.81	$0.00
Year 3	$1,819.58	$0.00
Year 4	$1,866.53	$0.00
Year 5	$1,914.68	$3.63
Year 6	$1,964.09	$8.94
Year 7	$2,014.76	$13.75
Year 8	$2,066.75	$18.81
Year 9	$2,120.07	$24.12
Year 10	$2,174.77	$29.69
Year 11	$2,230.88	$30.45
Year 12	$2,288.44	$31.24
Year 13	$2,347.49	$32.04
Year 14	$2,408.06	$32.87
Year 15	$2,470.19	$33.72
Year 16	$2,533.92	$34.59
Year 17	$2,599.30	$35.48
Year 18	$2,666.37	$36.40
Year 19	$2,735.16	$37.33
Year 20	$2,805.73	$38.30
20-Year Total	$44,529.78	$441.34
20-Year NPV	$22,295.57	$176.80

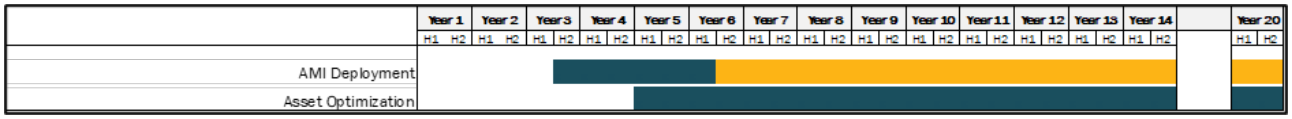
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization
	Number of Customers with AMI on Feeders with VVO (#)	Percentage of Customers with AMI on Feeders with VVO (%)	Monthly Carbon Reduction by Feeder (tons)
Year 1	0	0%	0.00

	Benefit Availability		Benefit Realization
	Number of Customers with AMI on Feeders with VVO (#)	Percentage of Customers with AMI on Feeders with VVO (%)	Monthly Carbon Reduction by Feeder (tons)
Year 2	0	0%	0.00
Year 3	0	0%	0.00
Year 4	0	0%	0.00
Year 5	133,035	11%	5.40
Year 6	321,260	22%	5.43
Year 7	489,118	33%	5.46
Year 8	661,940	43%	5.50
Year 9	839,836	54%	5.53
Year 10	1,022,920	65%	5.56
Year 11	1,038,264	65%	5.59
Year 12	1,053,838	65%	5.62
Year 13	1,069,646	65%	5.65
Year 14	1,085,690	65%	5.69
Year 15	1,101,976	65%	5.72
Year 16	1,118,505	65%	5.75
Year 17	1,135,283	65%	5.78
Year 18	1,152,312	65%	5.82
Year 19	1,169,597	65%	5.85
Year 20	1,187,141	65%	5.88

B.4 SYSTEM PLANNING OPTIMIZATION

(i) Asset Optimization



a. Description

The proliferation of AMI meters with the ability to sample voltage and current will support advanced analytics throughout the distribution network. These analytics would otherwise be dependent on deployment of dedicated line sensor monitoring devices, the volume of which can be eliminated in the presence of AMI.

The total costs for these sensors would otherwise be captured as a cost in Section B.6.i. – VVO Enablement; however, AMI meters and the associated communications network eliminate the need for sensors and any associated cellular charges as part of the VVO build-out and ongoing operations. This benefit is therefore driven by the avoided costs of sensors.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

Across 1,078 feeders, the Company estimates it can eliminate an average of 15 sensors per feeder, five (5) locations per feeder and three (3) sensors per location. The benefit includes the avoided sensor capital cost and cellular communications costs avoided through availability of the AMI mesh network.

Annual Benefit Calculations:

Business As Usual / Post-AMI Deployment Asset Optimization - Sensor Installation Cost Calculation:										
Feeders with VVO (#)	X	VVO Line Sensors per Feeder (#)	X	VVO Line Sensor Equipment, Labor, and Overhead Cost ($)	X	VVO Line Sensor Installation Duration (year)	X	Inflation (%)		
1,078		15		$7,491		1/6		2%		

Business As Usual / Post-AMI Deployment Asset Optimization - Sensor Cellular Charge Cost Calculation:										
Feeders with VVO (#)	X	VVO Line Sensors per Feeder (#)	X	Annual Cellular Fee per VVO Line Sensor ($)	X	Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X	Annual AMI Meters Deployed (%)	X	Inflation (%)
1,078		15		$100		17%-100%		17%-100%		2%

Asset Optimization List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Feeders with VVO (#)	1,078	65% of total feeders in Connecticut	More or less feeders than 65% could need VVO capabilities
VVO Line Sensor Equipment, Labor, and Overhead Cost ($)	$7,491	Company cost data	All-in sensor cost could increase faster or slower than 2% inflation
Annual Cellular Fee per VVO Line Sensor ($)	$100	Past cost estimate	Future cellular fees could increase faster or slower than 2% inflation

Asset Optimization List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
VVO Line Sensors per Feeder (#)	15	Five sensors per feeder and 3 phases per set	More than or less than 15 sensors per feeder may be needed
VVO Line Sensor Installation Duration (year)	6	Sensor installation would occur over 6 years during VVO implementation	Sensor installation and associated VVO implementation could be longer or shorter than 6 years
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Benefit Realization Over 6 Years of VVO Implementation Duration (%)	17%-100%	17% incremental benefit per year over the 6-year VVO implementation starting in Year 5 and completing in Year 10	Benefit from VVO could not be evenly dispersed over 6 years or take longer or shorter than 6 years to fully realize benefit
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

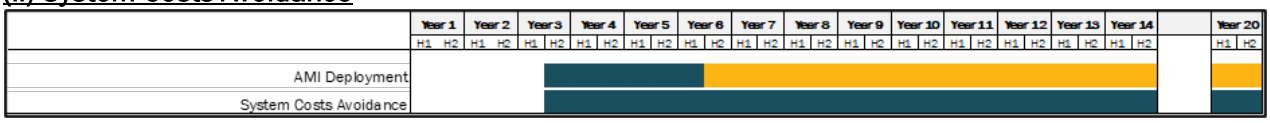
	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Sensor Capital Cost ($)	Baseline Sensor Cellular Charge Cost ($)	Total Baseline ($)	Sensor Capital Avoided Cost Benefit ($)	Sensor Cellular Charge Avoided Cost Benefit ($)	Total Benefit ($)
Year 1	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Year 3	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Year 4	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Year 5	$22.29	$0.25	**$22.54**	$22.29	$0.25	**$22.54**
Year 6	$22.73	$0.61	**$23.34**	$22.73	$0.61	**$23.34**
Year 7	$23.19	$0.93	**$24.12**	$23.19	$0.93	**$24.12**
Year 8	$23.65	$1.26	**$24.91**	$23.65	$1.26	**$24.91**
Year 9	$24.13	$1.61	**$25.73**	$24.13	$1.61	**$25.73**

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Sensor Capital Cost ($)	Baseline Sensor Cellular Charge Cost ($)	Total Baseline ($)	Sensor Capital Avoided Cost Benefit ($)	Sensor Cellular Charge Avoided Cost Benefit ($)	Total Benefit ($)
Year 10	$24.61	$1.97	**$26.58**	$24.61	$1.97	**$26.58**
Year 11	$0.00	$2.01	**$2.01**	$0.00	$2.01	**$2.01**
Year 12	$0.00	$2.05	**$2.05**	$0.00	$2.05	**$2.05**
Year 13	$0.00	$2.09	**$2.09**	$0.00	$2.09	**$2.09**
Year 14	$0.00	$2.13	**$2.13**	$0.00	$2.13	**$2.13**
Year 15	$0.00	$2.17	**$2.17**	$0.00	$2.17	**$2.17**
Year 16	$0.00	$2.22	**$2.22**	$0.00	$2.22	**$2.22**
Year 17	$0.00	$2.26	**$2.26**	$0.00	$2.26	**$2.26**
Year 18	$0.00	$2.31	**$2.31**	$0.00	$2.31	**$2.31**
Year 19	$0.00	$2.35	**$2.35**	$0.00	$2.35	**$2.35**
Year 20	$0.00	$2.40	**$2.40**	$0.00	$2.40	**$2.40**
20-Year Total	**$140.60**	**$28.61**	**$169.21**	**$140.60**	**$28.61**	**$169.21**
20-Year NPV	**$84.88**	**$11.53**	**$96.41**	**$84.88**	**$11.53**	**$96.41**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability	Benefit Realization		
	Number of Feeders Where Meters Perform Field Sensor Functions (#)	Actual Number of Sensors Avoided per Feeder (#)	Avoided Field Sensor Costs ($M)	Avoided Sensor Cellular Charges ($M)
Year 1	0	0	$0.00	$0.00
Year 2	0	0	$0.00	$0.00
Year 3	0	0	$0.00	$0.00
Year 4	0	0	$0.00	$0.00
Year 5	150	15	$22.29	$0.25
Year 6	359	15	$22.73	$0.61
Year 7	539	15	$23.19	$0.93
Year 8	719	15	$23.65	$1.26
Year 9	898	15	$24.13	$1.61
Year 10	1,078	15	$24.61	$1.97
Year 11	1,078	15	$0.00	$2.01
Year 12	1,078	15	$0.00	$2.05
Year 13	1,078	15	$0.00	$2.09
Year 14	1,078	15	$0.00	$2.13
Year 15	1,078	15	$0.00	$2.17
Year 16	1,078	15	$0.00	$2.22
Year 17	1,078	15	$0.00	$2.26
Year 18	1,078	15	$0.00	$2.31
Year 19	1,078	15	$0.00	$2.35
Year 20	1,078	15	$0.00	$2.40

(ii) System Costs Avoidance



a. Description

With the modernization of systems for AMI, there are several legacy systems that will be retired or have reduced utilization. C2 CIS is a current system that will be replaced with new solutions as part of the AMI project. As such, ongoing costs associated with each of the systems are avoided. For C2 CIS, portions of the mainframe support and supplier support are avoided.

As described in more detail in Section D.3.ii. – CIS, the Company will be installing a modern CIS system to enable the full benefits of AMI deployment. The current C2 CIS system would be adequate in a non-AMI environment; hence, the Company would continue to operate the legacy CIS in the near term in the absence of AMI. Nonetheless, in the future it will eventually cost more to maintain and add functionality to an aging C2 CIS than it would be to replace it. There is an avoided cost benefit by replacing C2 CIS sooner to enable AMI, as the costs will no longer be required in the future. The key avoided costs associated with a CIS replacement are assumed to be the same costs to implement and maintain a new CIS detailed in Section D.3.ii. – CIS. These benefits are considered an avoided cost, meaning that it represents labor, equipment, or system costs that Eversource would have incurred over the normal course of business without the system modernization elements of the AMI program.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

To calculate the avoided cost benefits, ongoing costs for each of the systems that will be retired or utilized substantially less were annualized and then escalated for inflation. For the C2 CIS cost avoidance, the same costs defined and calculated in Section D.3.ii. – CIS were inflated to 2033 and it is assumed the replacement occurs over 2.5 years.

Annual Benefit Calculations:

Avoided Systems Costs and Upgrades

System Costs Avoidance - Avoided CIS Annual Costs Calculation:				
Legacy C2 CIS System Annual O&M Costs ($)	X	Inflation (%)	X	Years of Avoided Cost
$586,560		2%		4

System Costs Avoidance - Avoided Survey Meter Annual Cellular Fees Calculation:

Number of Survey Meters (#)	X	Survey Meter Monthly Cellular Charges per Meter ($)	X	Months in Year	X	Inflation (%)
6,624		$0.54		12		2%

System Costs Avoidance List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Legacy C2 CIS System Annual O&M Costs ($)	$586,560	Company cost data. Cost begins after CIS is implemented and is avoided until avoided CIS replacement cost begins 3 years after CIS go-live	The cost could increase or decrease at a rate different from 2% inflation. Impacts to the CIS implementations could impact when these avoided cost benefits could begin
Number of Survey Meters (#)	6,624	Company data	Impacts to AMI deployment timeline could impact how many survey meters can avoid cellular costs each
Survey Meter Monthly Cellular Charges per Meter ($)	$0.54	Company cost data	The cost could increase or decrease at a rate different from 2% inflation
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

<u>Annual Benefit Calculations:</u>

CIS Avoided Costs

Avoided CIS Replacement - Internal Labor Calculation:						
CIS Internal Labor ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$6,775,511		2%		25%		94%

Avoid CIS Replacement - External Labor Calculation:						
CIS Services - Solution Integration Services ($)	+	CIS Third Party Services ($)	X	Inflation (%)	X	Contingency (%)
$51,980,488		$40,628,428		2%		20%

Avoided CIS Replacement - Hardware Calculation:

CIS Platform ($)	X	Inflation (%)	X	Contingency (%)
$2,389,908		2%		20%

Avoided CIS Replacement - Software Calculation:						
CIS Software ($)	+	CIS Other Implementation Costs ($)	X	Inflation (%)	X	Contingency (%)
$35,848,613		$19,716,737		2%		20%

Avoided CIS Replacement - Software Licensing / Fees Calculation:				
CIS Ongoing Licensing, Hosting, Support, and Admin Fees ($)	X	Contingency (%)	X	Inflation (%)
$9,375,968		20%		2%

System Costs Avoidance - CIS Replacement Avoided Costs List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
CIS Ongoing Licensing, Hosting, Support, and Admin Fees ($)	$9,375,968	Cost data from Massachusetts CIS implementation and repurposed as estimates for Connecticut, with allocation for MA	Current cost estimates could increase faster than inflation and the timeline for implementation could extend past 2 years, increasing costs
CIS Upfront Software ($)	$35,848,613		
CIS Platform ($)	$2,389,908		
CIS Services - Solution Integration Services ($)	$51,980,488		
CIS Internal Labor ($)	$6,775,511		
CIS Third Party Services ($)	$40,628,428		
CIS Other Implementation Costs ($)	$19,716,737		
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 25%

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)				Benefit Targets ($M)			
	Baseline CIS and MDMS Annual Costs	Baseline Survey Meter Annual Cellular Fees	Baseline CIS Replacement Cost	Baseline Total	Avoided CIS and MDMS Annual Costs Benefit	Avoided Survey Meter Annual Cellular Fees Benefit	Avoided CIS Replacement Cost Benefit	Benefit Total
Year 1	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.00	$0.01	$0.00	**$0.01**	$0.00	$0.01	$0.00	**$0.01**
Year 4	$0.63	$0.02	$0.00	**$0.66**	$0.63	$0.02	$0.00	**$0.66**
Year 5	$0.65	$0.04	$0.00	**$0.69**	$0.65	$0.04	$0.00	**$0.69**
Year 6	$0.66	$0.05	$0.00	**$0.71**	$0.66	$0.05	$0.00	**$0.71**
Year 7	$0.67	$0.05	$59.06	**$59.79**	$0.67	$0.05	$59.06	**$59.79**
Year 8	$0.69	$0.05	$123.20	**$123.93**	$0.69	$0.05	$123.20	**$123.93**
Year 9	$0.70	$0.05	$69.72	**$70.47**	$0.70	$0.05	$69.72	**$70.47**
Year 10	$0.00	$0.05	$11.25	**$11.30**	$0.00	$0.05	$11.25	**$11.30**
Year 11	$0.00	$0.05	$11.47	**$11.53**	$0.00	$0.05	$11.47	**$11.53**
Year 12	$0.00	$0.05	$11.70	**$11.76**	$0.00	$0.05	$11.70	**$11.76**
Year 13	$0.00	$0.06	$11.94	**$11.99**	$0.00	$0.06	$11.94	**$11.99**
Year 14	$0.00	$0.06	$12.18	**$12.23**	$0.00	$0.06	$12.18	**$12.23**
Year 15	$0.00	$0.06	$12.42	**$12.48**	$0.00	$0.06	$12.42	**$12.48**
Year 16	$0.00	$0.06	$12.67	**$12.73**	$0.00	$0.06	$12.67	**$12.73**
Year 17	$0.00	$0.06	$12.92	**$12.98**	$0.00	$0.06	$12.92	**$12.98**
Year 18	$0.00	$0.06	$13.18	**$13.24**	$0.00	$0.06	$13.18	**$13.24**
Year 19	$0.00	$0.06	$13.44	**$13.51**	$0.00	$0.06	$13.44	**$13.51**
Year 20	$0.00	$0.06	$13.71	**$13.78**	$0.00	$0.06	$13.71	**$13.78**
20-Year Total	**$4.01**	**$0.91**	**$388.87**	$393.78	**$4.01**	**$0.91**	**$388.87**	$393.78
20-Year NPV	**$2.59**	**$0.41**	**$196.49**	$199.49	**$2.59**	**$0.41**	**$196.49**	$199.49

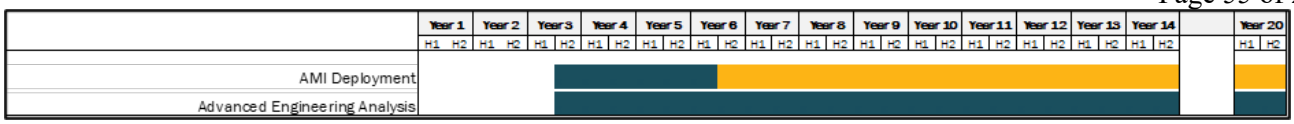
Benefit Targets are based on the data inputs and calculation methodologies detailed above and subject to all assumptions.

d. Data to Track the Availability and Realization of the Benefit

This benefit is not included in the benefit categories defined by PURA; therefore, it does not have defined data categories to track the availability and realization. The Company expects that the CIS, MDMS, and survey meter ongoing avoided costs benefits will become available upon full AMI deployment and the CIS replacement avoided costs occur in Year 7, when the legacy CIS would hypothetically be replaced absent AMI.

B.5 PROACTIVE OUTAGE PLANNING

(i). Advanced Engineering Analysis



a. Description

Granular AMI data enables advanced analyses that the Company can use to further improve grid operation while simultaneously cost-effectively maintaining the distribution system. In particular, transformer load monitoring ("TLM"), which is used to predict which transformers are at risk for overload, and thus failure, will benefit from granular AMI data. Based on loading information and characteristics of the transformers, the Company can determine when and which transformers are at risk for overloading, enabling them to plan replacements before a failure occurs. Currently, to estimate the health of a distribution transformer, engineers use historical energy and demand patterns to analyze peak timing and ascertain the relationship between peak load and total energy consumption. This analysis serves as the basis for a calculation to estimate the timing and magnitude of an individual customer's monthly peak load based on monthly consumption data collected via the drive-by AMR system.

With the growing penetration of behind-the-meter solar generation, among other factors, the historical TLM algorithm is less representative of future load patterns. Behind-the-meter solar generation and other changes to customer load profiles, such as participation in demand response programs and electric vehicle charging, further diminish the reliability of traditional TLM calculations.

By providing interval data at the customer premise level and more accurate mapping of the meter-to-transformer relationship, AMI meters will provide more granular and accurate information about the timing and magnitude of loading on individual transformers than is otherwise available. An AMI-enabled TLM calculation better reflects the diversity of load on a single transformer, greatly increasing the accuracy of results. This information will also be useful in enabling the Company to plan and design the system in response to trends like increased electric vehicle adoption in its service territory. As described by the U.S. Department of Energy in its 2021 report "An EV Future: Navigating the Transition" AMI can provide more visibility into customer charging patterns without resorting to calculations, informing specific load requirements and operational characteristics.[6] Moving beyond traditional TLM, access to interval data will enable engineers to expand analysis to minimum load periods and identify potential reverse flow overload conditions. See Section C.2.i. - More Accurate Load Profiles for a discussion of the additional qualitative benefits of AMI with respect to more accurate load profiles.

Incorporating the granular load information enabled by AMI into the TLM methodology will enable engineers to identify and avoid transformer failures to a greater extent. The outcome of this effort will be to drive a reduction in customer outages, some of them long duration outages, resulting in direct reliability and customer satisfaction benefits. Averting transformer overloads also has a financial

[6] U.S. Department of Energy. (2021). An EV Future: Navigating the Transition. https://www.energy.gov/sites/default/files/2024-01/14-10-2021_doe-voe-an-ev-future-report-2.pdf

benefit to the Company due to planning and scheduling the replacement ahead of time versus responding to and replacing the transformer on overtime or as emergent work. The benefit from avoided customer minutes of interruption ("CMI") is considered a customer savings benefit, meaning that the value is realized directly by customers through improved reliability. There will also be TLM benefits from the reduction in outage response costs, both in equipment and labor.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

The quantified avoided cost benefit of Advanced Engineering Analysis is based on the financial value of transformer equipment costs and the associated labor to perform the repair based on improved prediction of transformer overloads as a result of an AMI-enabled TLM methodology. On average, Eversource experiences 536 distribution transformer overloads or failures per year with the cost of equipment averaging $6,350.

The Company estimates that an improved TLM algorithm will proactively predict and address 70% of transformer failures that have historically occurred, and savings will accrue through the planned replacement of the transformer as opposed to repairing the failure on an emergency basis. Labor savings will accrue by avoiding overtime and additional time required to repair or replace the equipment.

Additionally, customers also receive a reliability improvement benefit from the avoidance of outages associated with transformer failures. While outages will still occasionally occur even with the replacement of transformers, these outages are shorter than those resulting from transformer failures, and can be planned to minimize impact on customers. The monetary benefit of these reduced outages was calculated using the US Department of Energy and Lawrence Berkeley National Lab's Interruption Cost Estimate ("ICE") calculator, which was developed to determine the monetary value to customers from an outage of a specified duration using value of service reliability studies.

<u>Annual Benefit Calculations</u>:

Business As Usual Advanced Engineering Analysis - Transformer Failure Equipment Costs Calculation:							
Transformers Failures/Overloads Yielding Damages (#)	X	Cost of Transformer Failure Damages ($)	X	Meter Growth (%)	X	Inflation (%)
536		$6,350		1.5%		2%

Post-AMI Deployment Advanced Engineering Analysis - Transformer Failure Equipment Costs Calculation:											
Transformers Failures/Overloads Yielding Damages (#)	X	Cost of Transformer Failure Damages ($)	X	Meter Growth (%)	X	Transformer Failures Mitigated Through Enhanced Voltage Monitoring and Asset Management (%)	X	Inflation (%)	X	Annual AMI Meters Deployed (%)
536		$6,350		1.5%		70%		2%		17%-100%

Business As Usual Advanced Engineering Analysis - Transformer Failure Labor Costs Calculation:											
Transformers Failures/Overloads Yielding Damages (#)	X	Meter Growth (%)	X	Replacement Labor Time Without AMI (hr)	X	Asset Response and Repair Crew Loaded Rate ($/hr)	X	Labor Overhead (%)	X	Inflation (%)
536		1.5%		13.33		$143		94%		2%

Post-AMI Deployment Usual Advanced Engineering Analysis - Transformer Overload Failure Labor Costs Calculation:													
Transformers Failures/ Overloads Yielding Damages (#)	X	Meter Growth (%)	X	Reduction in Replacement Labor Time with AMI (hr)	X	Asset Response and Repair Crew Loaded Rate ($/hr)	X	Transformer Failures Mitigated Through Enhanced Voltage Monitoring and Asset Mgmt (%)	X	Inflation (%)	X	Labor Overhead (%)	X	Annual AMI Meters Deployed (%)
536		1.5%		10.33		$143		70%		2%		94%		17%-100%

Business As Usual Advanced Engineering Analysis - Transformer Failure Reliability Savings Calculation:						
Customer Annual Minutes Interrupted from Transformer Failures and Overloads (min)	X	Weighted Average of Residential, Small C&I, and Large C&I Cost per Outage Minute ($)	X	Meter Growth (%)	X	Inflation (%)
1,359,628		$0.18		1.5%		2%

Post-AMI Deployment Usual Advanced Engineering Analysis - Transformer Failure Reliability Savings Calculation:													
Customer Annual Minutes Interrupted from Transformer Failures and Overloads (min)	X	Weighted Average of Residential, Small C&I, and Large C&I Cost per Outage Minute ($)	X	Transformer Failures Mitigated Through Enhanced Voltage Monitoring and Asset Management (%)	X	Process Efficiency between Planned and Unplanned Asset Failure/ Replacement Event (%)	X	AMI Enhanced Blue Sky Outage Awareness Benefit (%)	X	Meter Growth (%)	X	Annual AMI Meters Deployed (%)	X	Inflation (%)
1,359,628		$0.18		70%		67%		5%		1.5%		17%-100%		2%

Advanced Engineering Analysis List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Transformers Failures/Overloads Yielding Damages (#)	536	5-year average from 2021-2025	Meter growth is a long-term proxy for the increase in transformer failures/overloads. The actual amount could increase at more or less than this rate

Advanced Engineering Analysis List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Cost of Transformer Failure Damages ($)	$6,350	Past cost estimate	The cost could increase faster or slower than 2% inflation
Transformer Failures Mitigated Through Enhanced Voltage Monitoring and Asset Management (%)	70%	Industry benchmark and estimate	The actual number of future transformer failures/overloads mitigated could be greater or less than this amount
Asset Response and Repair Crew Rate ($/hr)	$143	Company cost data	The cost could increase faster or slower than 2% inflation
Replacement Labor Time Without AMI (hr)	13.33	Company labor efficiency data	The average transformer replacement labor time could increase or decrease in the future
Reduction in Replacement Labor Time with AMI (hr)	10.33	Industry benchmark and Company estimate	The amount of reduced labor time for a transformer replacement could be more or less than this amount
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meters could grow greater or less than 1.5%
Weighted Average of Residential, Small C&I, and Large C&I Cost per Outage Minute ($)	$0.18	Interruption Cost Estimate (ICE) Calculator Estimate of Interruption Costs. Weighted average of residential, small C&I and large C&I customer. Small C&I	The weighted average cost per outage minute may be more or less than $0.18 per minute and may increase faster than 2% inflation

Advanced Engineering Analysis List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
		and large C&I values are reduced by 95%	
Customer Annual Minutes Interrupted from Transformer Failures and Overloads (min)	1,359,628	5-year average from 2021-2025	Meter growth is a long-term proxy for the increase in this amount and the actual amount could increase more or less than this rate
AMI Enhanced Blue Sky Outage Awareness Benefit (%)	5%	Industry benchmark and Company estimate	Outage awareness benefit may be greater than or less than 5%
Process Efficiency Between Planned and Unplanned Asset Failure/Replacement Event (%)	67%	Industry benchmark and Company estimate	Process efficiency may be greater than or less than 67%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)				Benefit Targets ($M)			
	Baseline Transformer Overload and Failure Equipment Costs ($)	Baseline Transformer Overload and Failure Labor Costs ($)	Baseline Transformer Overload and Failure Customer Outage Costs ($)	Baseline Total ($)	Transformer Overload and Failure Equipment Avoided Cost Savings ($)	Transformer Overload and Failure Labor Avoided Cost Savings ($)	Transformer Overload and Failure Customer Outage Savings ($)	Benefit Total ($)
Year 1	$3.52	$2.05	$0.25	**$5.83**	$0.00	$0.00	$0.00	**$0.00**
Year 2	$3.65	$2.12	$0.26	**$6.03**	$0.00	$0.00	$0.00	**$0.00**
Year 3	$3.78	$2.20	$0.27	**$6.25**	$0.44	$0.20	$0.00	**$0.64**
Year 4	$3.91	$2.28	$0.28	**$6.47**	$1.37	$0.62	$0.00	**$1.99**
Year 5	$4.05	$2.36	$0.29	**$6.70**	$2.36	$1.07	$0.01	**$3.43**
Year 6	$4.19	$2.44	$0.30	**$6.93**	$2.93	$1.32	$0.01	**$4.26**
Year 7	$4.34	$2.53	$0.31	**$7.18**	$3.04	$1.37	$0.01	**$4.42**
Year 8	$4.49	$2.62	$0.32	**$7.43**	$3.14	$1.42	$0.01	**$4.57**
Year 9	$4.65	$2.71	$0.33	**$7.69**	$3.26	$1.47	$0.01	**$4.73**
Year 10	$4.82	$2.80	$0.34	**$7.96**	$3.37	$1.52	$0.01	**$4.90**
Year 11	$4.99	$2.90	$0.36	**$8.25**	$3.49	$1.57	$0.01	**$5.07**

	Business As Usual ($M)				Benefit Targets ($M)			
	Baseline Transformer Overload and Failure Equipment Costs ($)	Baseline Transformer Overload and Failure Labor Costs ($)	Baseline Transformer Overload and Failure Customer Outage Costs ($)	Baseline Total ($)	Transformer Overload and Failure Equipment Avoided Cost Savings ($)	Transformer Overload and Failure Labor Avoided Cost Savings ($)	Transformer Overload and Failure Customer Outage Savings ($)	Benefit Total ($)
Year 12	$5.16	$3.01	$0.37	**$8.54**	$3.61	$1.63	$0.01	**$5.25**
Year 13	$5.34	$3.11	$0.38	**$8.84**	$3.74	$1.69	$0.01	**$5.44**
Year 14	$5.53	$3.22	$0.40	**$9.15**	$3.87	$1.75	$0.01	**$5.63**
Year 15	$5.73	$3.34	$0.41	**$9.47**	$4.01	$1.81	$0.01	**$5.83**
Year 16	$5.93	$3.45	$0.42	**$9.81**	$4.15	$1.87	$0.01	**$6.03**
Year 17	$6.14	$3.57	$0.44	**$10.15**	$4.30	$1.94	$0.01	**$6.25**
Year 18	$6.36	$3.70	$0.46	**$10.51**	$4.45	$2.01	$0.01	**$6.47**
Year 19	$6.58	$3.83	$0.47	**$10.88**	$4.61	$2.08	$0.01	**$6.70**
Year 20	$6.81	$3.97	$0.49	**$11.27**	$4.77	$2.15	$0.01	**$6.93**
20-Year Total	**$99.96**	**$58.21**	**$7.16**	**$165.33**	**$60.91**	**$27.49**	**$0.15**	**$88.54**
20-Year NPV	**$49.03**	**$28.55**	**$3.51**	**$81.09**	**$26.61**	**$12.01**	**$0.06**	**$38.68**

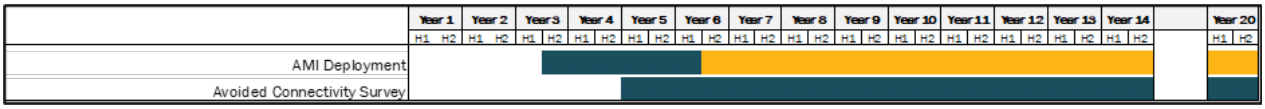
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization		
	Date when Systems are Available	Number of Transformers Analyzed (#)	Number of Transformer Failures per Year Compared to Historical Baseline (#)	Estimated Reduced Costs Based on Actual Number Of Transformer Replacements Per Year ($M)	Number of Outages Avoided Based on Avoided Transformer Failures (#)**
Year 1	Not Available	*	544	$0.00	0
Year 2	Not Available	*	552	$0.00	0
Year 3	Available	*	495	$0.64	690
Year 4	Available	*	370	$1.99	2,102
Year 5	Available	*	241	$3.43	3,557
Year 6	Available	*	176	$4.26	4,332
Year 7	Available	*	178	$4.41	4,397
Year 8	Available	*	181	$4.56	4,463
Year 9	Available	*	184	$4.72	4,530
Year 10	Available	*	187	$4.89	4,598
Year 11	Available	*	189	$5.06	4,667
Year 12	Available	*	192	$5.24	4,737
Year 13	Available	*	195	$5.43	4,808
Year 14	Available	*	198	$5.62	4,880
Year 15	Available	*	201	$5.82	4,953
Year 16	Available	*	204	$6.02	5,027
Year 17	Available	*	207	$6.24	5,103
Year 18	Available	*	210	$6.46	5,179
Year 19	Available	*	213	$6.68	5,257
Year 20	Available	*	217	$6.92	5,336

*Eversource will pilot advanced load monitoring on 50,000 meters as part of the initial AMI deployment. The Company will determine long-term use based on the performance of the solution and overall business case value. Using analytics, the Company would be able to target 100% of the transformers using traditional interval-data based methods but is expected to be less accurate than utilizing distributed intelligence applications.

**There were 536 transformer failures that impacted 5,768 customers on average between 2021-2025; therefore, each transformer failure impacts 11 customers (5,768/536) on average.

(ii) Avoided Connectivity Survey



a. Description

One of the key factors currently hindering situational awareness at the grid edge is the inaccurate or incomplete mapping of the connectivity between individual customer meters, their distribution transformer, and that transformer's phase connection on the 3-phase distribution system. Awareness of this connectivity is an essential tool for the OMS to identify the location of outages. Inaccuracies in the modeling of customer-to-transformer relationships can result in service delays or operational inefficiencies. Additional delays in outage restoration occur when customers are misidentified on the wrong phase of the distribution system in the OMS.

Historically, accurate customer-to-transformer connectivity and customer phase identification has been a challenge to maintain given the dynamic nature of the distribution system and the manual intervention that occurs over time. To maintain accurate records and support efficient restoration with timely and actionable customer communications, Eversource conducts periodic GIS field surveys to identify and correct connectivity records. Today, these surveys are performed via a physical walk-down of the entire overhead distribution system, requiring significant labor resources. The availability of granular AMI data from all customer meters to support statistical analysis combined with the on-board intelligence capabilities of the new meter technology have the potential to drastically reduce the need for periodic physical walk-down GIS surveys. With the ability for meters to communicate locally, they can use system data to remotely calculate their position on the distribution system and transmit that information over the AMI communications network.

Granular data available with a full AMI deployment, combined with other field telemetry, can be used in statistical analysis to provide accurate phase identification. Specifically, in areas of high solar penetration this is valuable information as system balancing is increasingly difficult to achieve. As described in the 2019 National Renewable Energy Laboratory report, "Considerations for AMI-Based Operations for Distribution Feeders,"[2] researchers have demonstrated methodologies for statistical analysis using AMI data to correct inaccurate customer phasing information. Advances in meter technology also support accurate meter-to-transformer connectivity.

Accurate customer connectivity records are necessary for regulatory reporting of reliability and regulatory compliance. The Company tracks circuit performance as part of the annual Transmission & Distribution Reliability Performance (TDRP) Report, and identifies the worst performing circuits along with Reliability Corrective Action Plans. Accurate customer connectivity records enable cost optimization and targeted deployment of investments to these circuits, ensuring customers are realizing the benefits of connectivity and reliability tracking at substantially reduced cost.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

Calculation of the savings associated with avoiding physical walk-down GIS surveys assumes an annualized cost of $758,452 to execute the connectivity survey. The savings calculation also includes a financial benefit of avoided miles driven to conduct the survey, which is estimated at 9,009 miles per year, and a cost of $1.27 per mile. Quantification of the associated carbon reduction benefit is not included as a quantitative benefit, but the Company views this as an additional qualitative benefit.

Annual Benefit Calculations:

Business As Usual Avoided Connectivity Survey - Labor and Material Cost Calculation:				
Annual Labor and Material Cost of Connectivity Field Survey ($)	X	Meter Growth (%)	X	Inflation (%)
$758,452		1.5%		2%

Post-AMI Deployment Avoided Connectivity Survey - Labor and Material Cost Calculation:								
Annual Labor and Material Cost of Connectivity Field Survey ($)	X	Annual AMI Meters Deployed (%)	X	Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X	Meter Growth (%)	X	Inflation (%)
$758,452		17%-100%		17%-100%		1.5%		2%

Business As Usual Avoided Connectivity Survey - Vehicle Cost Calculation:						
Annualized Miles Driven per Connectivity Survey (miles)	X	Cost per Mile Driven ($/mile)	X	Meter Growth (%)	X	Inflation (%)
9,009		$1.27		1.5%		2%

Post-AMI Deployment Avoided Connectivity Survey - Vehicle Cost Calculation:										
Annualized Miles Driven per Connectivity Survey (miles)	X	Cost per Mile Driven ($/mile)	X	Annual AMI Meters Deployed (%)	X	Benefit Realization Over 6 Years of VVO Implementation Duration (%)	X	Meter Growth (%)	X	Inflation (%)
9,009		$1.27		17%-100%		17%-100%		1.5%		2%

Avoided Connectivity List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual Labor and Material Cost of Connectivity Field Survey ($)	$758,452	Average cost per year over past 10 years	The cost per connectivity survey could increase more than this amount in the future
Cost per Mile Driven ($/mile)	$1.27	General mileage rate, in line with IRS guidance	Actual cost per mile driven could be higher or lower than this value and could increase higher or lower than 2% inflations
Annualized Miles Driven per Connectivity Survey (miles)	9,009	Company data	Number of miles in the future may be more or less than this amount as meter growth is used a long-term proxy
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meters could grow greater or less than 1.5%
Benefit Realization Over 6 Years of VVO Implementation Duration (%)	17%-100%	17% incremental benefit per year over the 6-year VVO implementation starting in Year 5 and completing in Year 10	Benefit from VVO could not be evenly dispersed over 6 years or take longer or shorter than 6 years to fully realize benefit
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by	AMI meters deployed could be greater

Avoided Connectivity List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
		end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	than or less than the annual projections

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Connectivity Survey Labor Costs	Baseline Connectivity Survey Vehicle Costs	Baseline Total	Connectivity Survey Labor Avoid Cost Savings	Connectivity Survey Vehicle Avoided Cost Savings	Benefit Total
Year 1	$0.79	$0.01	**$0.80**	$0.00	$0.00	**$0.00**
Year 2	$0.81	$0.01	**$0.83**	$0.00	$0.00	**$0.00**
Year 3	$0.84	$0.01	**$0.85**	$0.00	$0.00	**$0.00**
Year 4	$0.87	$0.01	**$0.88**	$0.00	$0.00	**$0.00**
Year 5	$0.90	$0.01	**$0.92**	$0.13	$0.00	**$0.13**
Year 6	$0.93	$0.01	**$0.95**	$0.31	$0.00	**$0.32**
Year 7	$0.97	$0.01	**$0.98**	$0.48	$0.01	**$0.49**
Year 8	$1.00	$0.02	**$1.02**	$0.67	$0.01	**$0.68**
Year 9	$1.04	$0.02	**$1.05**	$0.86	$0.01	**$0.88**
Year 10	$1.07	$0.02	**$1.09**	$1.07	$0.02	**$1.09**
Year 11	$1.11	$0.02	**$1.13**	$1.11	$0.02	**$1.13**
Year 12	$1.15	$0.02	**$1.17**	$1.15	$0.02	**$1.17**
Year 13	$1.19	$0.02	**$1.21**	$1.19	$0.02	**$1.21**
Year 14	$1.23	$0.02	**$1.25**	$1.23	$0.02	**$1.25**
Year 15	$1.28	$0.02	**$1.30**	$1.28	$0.02	**$1.30**
Year 16	$1.32	$0.02	**$1.34**	$1.32	$0.02	**$1.34**
Year 17	$1.37	$0.02	**$1.39**	$1.37	$0.02	**$1.39**
Year 18	$1.42	$0.02	**$1.44**	$1.42	$0.02	**$1.44**
Year 19	$1.47	$0.02	**$1.49**	$1.47	$0.02	**$1.49**
Year 20	$1.52	$0.02	**$1.54**	$1.52	$0.02	**$1.54**
20-Year Total	**$22.27**	**$0.34**	$22.61	**$16.57**	**$0.25**	$16.82
20-Year NPV	**$10.93**	**$0.16**	$11.09	**$6.57**	**$0.10**	$6.67

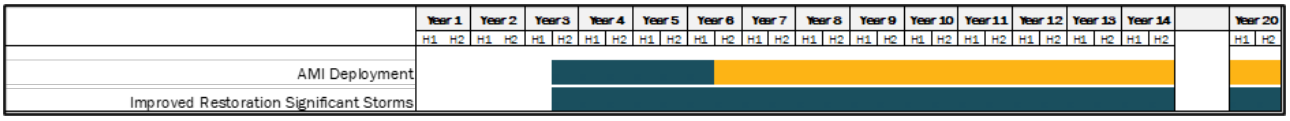
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization		
	Date When Systems are Available	Number of Feeders Monitored	Annual Avoided Costs ($M)	Number of Field Surveys Conducted (#)	Reduced Miles Driven Due to Avoided Surveys (#)
Year 1	Not Available	0	$0.00	*	0
Year 2	Not Available	0	$0.00	*	0
Year 3	Not Available	0	$0.00	*	0
Year 4	Not Available	0	$0.00	*	0
Year 5	Available	150	$0.13	*	1,348
Year 6	Available	359	$0.32	*	3,284
Year 7	Available	539	$0.49	*	4,999
Year 8	Available	719	$0.68	*	6,766
Year 9	Available	898	$0.88	*	8,584
Year 10	Available	1,078	$1.09	*	10,455
Year 11	Available	1,078	$1.13	*	10,612
Year 12	Available	1,078	$1.17	*	10,771
Year 13	Available	1,078	$1.21	*	10,933
Year 14	Available	1,078	$1.25	*	11,097
Year 15	Available	1,078	$1.30	*	11,263
Year 16	Available	1,078	$1.34	*	11,432
Year 17	Available	1,078	$1.39	*	11,604
Year 18	Available	1,078	$1.44	*	11,778
Year 19	Available	1,078	$1.49	*	11,954
Year 20	Available	1,078	$1.54	*	12,134

*Field surveys will not be conducted with AMI

B.6 EARLY OUTAGE DETECTION

(i) Improved Restoration Significant Storms



a. Description

Weather events can cause outages on the distribution system with varying degrees of severity. As described in the Company's Emergency Response Plan, significant events consist of four stages: pre-event preparedness; mobilization and initial response; sustained actions; and demobilization and post-event analysis and reporting. As the system begins to take on damage in a significant event, thousands of customers call the Company or use digital channels in a condensed period of time to report an outage. The OMS applies algorithms to predict total number of customers out of power and the number of damage locations. In the period of sustained action during a significant event, thousands of internal and external resources work to identify damages, prioritize and plan restoration activities, repair the

identified damages and restore power to customers. Planning and prioritization efforts largely focus on developing strategies to safely restore the greatest number of customers as quickly as possible. Once any transmission or substation damage has been addressed, prioritization typically focuses on the system backbone. As crews restore these backbone areas, nested outages often go undetected for some time. Currently, the Company largely relies on customers to communicate that they are still without power. As restoration activities near completion (e.g., approximately 99 percent of customers restored), the focus is on addressing these remaining pockets of nested outages.

Many of these "single no lights" calls require a field visit from either internal or external resources to verify that power is in fact restored, diverting resources from other restoration activities. The benefit of AMI in a significant storm is its ability to capture accurate, real-time data regarding the state of the system at the very beginning of the event, as outages unfold, and as restoration progresses, including damage locations and the actual number of customers without service, supporting OMS calculations of the numbers of trouble spots. This information improves the data utilized in the resource planning process, including with respect to procurement of external mutual aid crews. Upon integration with the OMS, AMI enables utilities to isolate outages faster and dispatch repair crews more precisely, reducing outage duration, limiting inconvenience, and reducing labor hours and truck rolls for outage diagnosis and restoration. Importantly, with AMI, the Company will be able to provide customers with more accurate information on the status of their outage.

This benefit is based on the same underlying AMI functionality described in the No Trouble Found ("NTF") Calls Reduction and Improved Restoration – Blue Sky sections: real-time outage visibility, remote confirmation of service status, and improved targeting of field response. In this section, those same capabilities are applied at scale during major events to improve restoration planning, locate nested outages, and reduce unnecessary field verification visits.

The benefit from avoided or reduced customer outage time is a savings benefit realized directly by customers. Over time, customers also enjoy the lower costs of the more efficient outage response.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

Using historical outage data, the Company analyzed the avoided cost impact of all catastrophic storm events between 2020-2025. Catastrophic storms are events where incremental costs to restore power meet or exceed the threshold of $4M for events occurring after May 1, 2018, and $5M for events prior to May 1, 2018. This analysis determined a representative number of 11 storms per year with an average cost of $20 million per event; approximately 69,189 customers affected per event and an average outage duration of 55 hours. Realizing each event is unique and depending on the expense type, the Company estimates the potential of between 6% to 13% avoided cost reduction in significant storm expenses, on average, per storm.

The monetary benefit of these reduced outages for customers was calculated using ICE calculator described in Section B.5.i. – Advanced Engineering Analysis. It is assumed that approximately 1% of the customers impacted by the event will benefit from an outage reduction.

It is important to note that the realized avoided cost in the future (compared to a non-AMI baseline) will be nearly impossible to calculate due to the high level of variability in the volume and severity of storm activity year-to-year. The 2020-2025 5-year significant storm average of 11 storms per year are projected forward for the purposes of this analysis, while costs increase at an assumed 2% inflation rate.

Annual Benefit Calculations:

Business As Usual Improved Restoration - Significant Storms Spend Calculation:				
Total Average Spend per Significant Storm	X	Significant Storm Frequency Per Year (#)	X	Inflation (%)
$19,951,334		11		2%

Post-AMI Deployment Improved Restoration - Significant Storms Spend Calculation:									
Total Average Spend per Significant Storm	X	Significant Storm Frequency Per Year (#)	X	Annual AMI Meters Deployed (%)	X	Significant Storm Spend Reduction through AMI (%)	X	Inflation (%)	
$19,951,334		11		17%-100%		6%-13%		2%	

Business As Usual Improved Restoration Significant Storms - Customer Outage Savings Reduction Calculation:													
Number of Customers Interrupted per Significant Storm (#)	X	Significant Storm Average Duration (hr)	X	Minutes in Hour	X	Significant Storm Frequency Per Year (#)	X	Weighted Average of Residential and C&I Cost per Outage Minute ($)	X	Meter Growth (%)	X	Inflation (%)	
69,189		55		60		11		$0.18		1.5%		2%	

Post-AMI Deployment Improved Restoration Significant Storms – Customer Outage Savings Reduction Calculation:															
Number of Customers Interrupted per Significant Storm (#)	X	Significant Storm Average Duration (hr)	X	Minutes in Hour	X	Significant Storm Frequency Per Year (#)	X	Weighted Average of Res. and C&I Cost per Outage Minute ($)	X	Significant Storm Spend Reduction through AMI (%)	X	Significant Storm Percent of Customers on Outage Tail (%)	X	Meter Growth (%)	X	Inflation (%)
69,189		55		60		11		$0.18		6%-13%		1%		1.5%		2%

Improved Restoration Significant Storms List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Total Average Spend per Significant Storm ($)	$19,951,334	2020-2025 5-year average. Significant Storms are "catastrophic" storms with incremental costs that meet or exceed the threshold of $4M for events post May 1, 2018, and $5M for events prior to May 1, 2018	The Company cost for each significant storm may increase at a rate greater than 2% inflation
Significant Storm Frequency Per Year (#)	11		The number of significant storms may increase more or less than this amount. No increase in the number of significant storms per year is assumed
Number of Customers Interrupted per Significant Storm (#)	69,189		Meter growth is a used a long-term proxy for the increase in the number of customers interrupted per significant storm and the actual amount could be more or less than this value
Significant Storm Average Duration (hr)	55		Future storm durations could be greater than or less than this value. It is assumed that the average significant storm duration remains this duration in the future
Significant Storm Spend Reduction through AMI (%)	6%-13%	Company estimate	Significant Storm spend reduction due to AMI may be higher or lower than this estimated range
Significant Storm Percent of Customers on Outage Tail (%)	1%	Company estimate	The percent of customers that benefit from an outage reduction could be greater or less than 1%
Weighted Average of Residential, and C&I Cost per Outage Minute ($)	$0.18	Interruption Cost Estimate (ICE) Calculator Estimate of Interruption Costs. Weighted average of residential and C&I customers. C&I values are reduced by 95%	The weighted average cost per outage minute may be more or less than $0.18 per minute and may increase faster than 2% inflation
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meters could grow greater or less than 1.5%
Inflation (%)	2%	PURA Requirement	Inflation may be higher than 2%

Improved Restoration Significant Storms List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

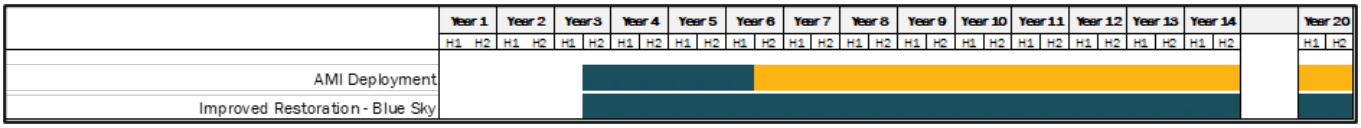
	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Significant Storm Restoration Expense Costs	Baseline Significant Storm Customer Outage Costs	Baseline Total	Significant Storm Avoided Costs from Improved Restoration	Significant Storm Customer Outage Savings from Improved Restoration	Benefit Total
Year 1	$215.79	$42.58	**$258.37**	$0.00	$0.00	**$0.00**
Year 2	$220.11	$44.08	**$264.19**	$0.00	$0.00	**$0.00**
Year 3	$224.51	$45.64	**$270.15**	$2.95	$0.10	**$3.04**
Year 4	$229.00	$47.25	**$276.25**	$9.01	$0.30	**$9.31**
Year 5	$233.58	$48.92	**$282.50**	$15.32	$0.50	**$15.83**
Year 6	$238.25	$50.64	**$288.89**	$18.76	$0.62	**$19.37**
Year 7	$243.02	$52.43	**$295.45**	$19.13	$0.63	**$19.76**
Year 8	$247.88	$54.28	**$302.16**	$19.51	$0.64	**$20.16**
Year 9	$252.83	$56.20	**$309.03**	$19.90	$0.66	**$20.56**
Year 10	$257.89	$58.18	**$316.07**	$20.30	$0.67	**$20.97**
Year 11	$263.05	$60.24	**$323.28**	$20.71	$0.68	**$21.39**
Year 12	$268.31	$62.36	**$330.67**	$21.12	$0.70	**$21.82**
Year 13	$273.67	$64.56	**$338.24**	$21.54	$0.71	**$22.25**
Year 14	$279.15	$66.84	**$345.99**	$21.98	$0.72	**$22.70**
Year 15	$284.73	$69.20	**$353.93**	$22.42	$0.74	**$23.15**
Year 16	$290.43	$71.65	**$362.07**	$22.86	$0.75	**$23.62**
Year 17	$296.23	$74.17	**$370.41**	$23.32	$0.77	**$24.09**
Year 18	$302.16	$76.79	**$378.95**	$23.79	$0.78	**$24.57**
Year 19	$308.20	$79.50	**$387.71**	$24.26	$0.80	**$25.06**
Year 20	$314.37	$82.31	**$396.68**	$24.75	$0.81	**$25.56**
20-Year Total	$5,243.14	$1,207.83	**$6,450.98**	**$351.64**	**$11.58**	**$363.22**
20-Year NPV	$2,658.55	$592.44	**$3,250.99**	**$157.20**	**$5.18**	**$162.37**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability				Benefit Realization		
	Number of Customers with Capability by Month (#)	Percent of Customers with Capability (%)	Number of Service Transformers with at Least Two AMI Meters (#)	Percent of Service Transformers with at Least Two AMI Meters (%)	Number of Significant Storm Events (#)	Estimated Reduced Restoration Costs Based on Significant Storm Event Characteristics ($M)	Estimated Value of Avoided Interruptions to Customers Based on Significant Storm Event Characteristics ($M)
Year 1	0	0%	*	*	11	$0.00	$0.00
Year 2	0	0%	*	*	11	$0.00	$0.00
Year 3	253,767	17%	*	*	11	$2.95	$0.10
Year 4	740,661	50%	*	*	11	$9.01	$0.30
Year 5	1,228,013	83%	*	*	11	$15.32	$0.50
Year 6	1,482,737	100%	*	*	11	$18.76	$0.62
Year 7	1,504,979	100%	*	*	11	$19.13	$0.63
Year 8	1,527,553	100%	*	*	11	$19.51	$0.64
Year 9	1,550,467	100%	*	*	11	$19.90	$0.66
Year 10	1,573,724	100%	*	*	11	$20.30	$0.67
Year 11	1,597,329	100%	*	*	11	$20.71	$0.68
Year 12	1,621,289	100%	*	*	11	$21.12	$0.70
Year 13	1,645,609	100%	*	*	11	$21.54	$0.71
Year 14	1,670,293	100%	*	*	11	$21.98	$0.72
Year 15	1,695,347	100%	*	*	11	$22.42	$0.74
Year 16	1,720,777	100%	*	*	11	$22.86	$0.75
Year 17	1,746,589	100%	*	*	11	$23.32	$0.77
Year 18	1,772,788	100%	*	*	11	$23.79	$0.78
Year 19	1,799,380	100%	*	*	11	$24.26	$0.80
Year 20	1,826,370	100%	*	*	11	$24.75	$0.81

*Eversource does not currently have an existing AMI base

(ii) <u>Improved Restoration – Blue Sky</u>



a. Description

"Blue Sky" days are days with relatively fewer trouble spots and can also be referred to as minor storm and non-storm days. Outages during blue sky days are often the result of trees, but other common causes include equipment damage, animal contact, or vehicles hitting electrical equipment. The Company currently relies on customer calls and digital outage reports, and SCADA data to know when these outages occur.

AMI provides increased awareness of outage occurrence and location, due to the fact that "last gasp" outage notifications are sent immediately to the Company following a customer outage event. Although the duration of outage restoration (as measured by Customer Average Interruption Duration Index ("CAIDI")) is not expected to be materially impacted by AMI, early notification will allow the Company to dispatch crews upon receiving the last gasp notification rather than waiting on the customer to call and report the outage. Faster dispatch results in power being restored more quickly than it would have been without AMI with an expected improvement in response time of approximately two minutes per outage.

These benefits rely on the same core AMI functionality described in the Significant Storm and NTF sections—namely, real-time meter communications, improved outage visibility, and better-informed field response. In Blue Sky conditions, that same functionality is applied to smaller-scale outage events, enabling earlier awareness and dispatch, while in the other sections it supports large-event restoration and the avoidance of unnecessary premise-level truck rolls. This benefit is considered a customer savings benefit, meaning that the value is realized directly by customers through improved reliability. Additionally, while not quantified as a benefit and is further detailed in Section C.1.i. – Outage Restoration Notifications, call volume may be reduced since the Company can send proactive notifications to inform impacted customers of the outage and a more accurate time to restore.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

The early notification benefit is estimated to be roughly a two-minute improvement relative to current customer experience outage duration. Customers for whom power is restored more quickly than it would have been without AMI will place a value on that benefit, and an estimate of that benefit for residential, small C&I and large C&I customers was determined using the ICE calculator described in Section B.5.i. – Advanced Engineering Analysis. A weighted average of the benefit value for different customer groups is calculated based on their proportion of total energy use. This weighted average is multiplied by the number of service interruption minutes per year that are eliminated as crews have a two-minute quicker response time.

<u>Annual Benefit Calculations</u>:

Business As Usual Improve Restoration - Blue Sky Calculation:								
Phase Wires Down: Customer Outage Hours (hr)	+	Minor Storm Outage: Customer Outage Hours (hr)	X	Minutes in Hour	X	Weighted Average of Residential and C&I Cost per Outage Minute ($)	X	Inflation (%)
666,356		744,276		60		$0.18		2%

Post-AMI Deployment Improve Restoration - Blue Sky Calculation:												
Phase Wires Down: Customer Outage Hours Reduction From 2-Minute Faster Response (hr)	+	Minor Storm Outage: Customer Outage Hours Reduction from 2-Minute Faster Response (hr)	X	Minutes in Hour	X	Weighted Average of Residential and C&I Cost per Outage Minute ($)	X	Inflation (%)	X	Meter Growth (%)	X	Annual AMI Meters Deployed (%)
11,301		9,571		60		$0.18		2%		1.5%		17%-100%

Improved Restoration - Blue Sky List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Phase Wires Down: Customer Outage Hours (hr)	666,356	2021-2025 5-year average	The customer outage hours from phase wires down and minor storms could be greater than or less than the recent 5-year average. Meter growth is used as a long-term proxy for an increase, but the actual increase could be more or less than this estimate
Phase Wires Down: Customer Outage Hours Reduction From 2-Minute Faster Response (hr)	11,301	Reduction of 2021-2025 5-Year average assuming crews arrive 2-minutes faster	
Minor Storm Outage: Customer Outage Hours (hr)	744,276	2021-2025 5-year average	
Minor Storm Outage: Customer Outage Hours Reduction from 2-Minute Faster Response (hr)	9,571	Reduction of 2021-2025 5-Year average assuming crews arrive 2-minutes faster	
Weighted Average of Residential, Small C&I, and Large C&I Cost per Outage Minute ($)	$0.18	Interruption Cost Estimate (ICE) Calculator Estimate of Interruption Costs. Weighted average of residential, and C&I customers. C&I values are reduced by 95%	The weighted average cost per outage minute may be more or less than $0.10 per minute and may increase faster than 2% inflation
Inflation (%)	2%	PURA requirement	Inflation may be higher than 2%
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

Improved Restoration - Blue Sky List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meters could grow greater or less than 1.5%

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Minor Storm Events Cost	Baseline Blue Sky (Phase Wires Down) Events Cost	Baseline Total	Minor Storm Events 2-Minute Faster Response Customer Benefit	Blue Sky (Phase Wires Down) Events 2-Minute Faster Response Customer Benefit	Benefit Total
Year 1	$8.29	$7.42	**$15.71**	$0.00	$0.00	**$0.00**
Year 2	$8.58	$7.68	**$16.27**	$0.00	$0.00	**$0.00**
Year 3	$8.89	$7.96	**$16.84**	$0.02	$0.02	**$0.04**
Year 4	$9.20	$8.24	**$17.44**	$0.06	$0.07	**$0.13**
Year 5	$9.52	$8.53	**$18.05**	$0.10	$0.12	**$0.22**
Year 6	$9.86	$8.83	**$18.69**	$0.13	$0.15	**$0.28**
Year 7	$10.21	$9.14	**$19.35**	$0.13	$0.16	**$0.29**
Year 8	$10.57	$9.46	**$20.03**	$0.14	$0.16	**$0.30**
Year 9	$10.94	$9.80	**$20.74**	$0.14	$0.17	**$0.31**
Year 10	$11.33	$10.14	**$21.47**	$0.15	$0.17	**$0.32**
Year 11	$11.73	$10.50	**$22.23**	$0.15	$0.18	**$0.33**
Year 12	$12.14	$10.87	**$23.01**	$0.16	$0.18	**$0.34**
Year 13	$12.57	$11.26	**$23.83**	$0.16	$0.19	**$0.35**
Year 14	$13.02	$11.65	**$24.67**	$0.17	$0.20	**$0.36**
Year 15	$13.47	$12.06	**$25.54**	$0.17	$0.20	**$0.38**
Year 16	$13.95	$12.49	**$26.44**	$0.18	$0.21	**$0.39**
Year 17	$14.44	$12.93	**$27.37**	$0.19	$0.22	**$0.41**
Year 18	$14.95	$13.39	**$28.34**	$0.19	$0.23	**$0.42**
Year 19	$15.48	$13.86	**$29.34**	$0.20	$0.24	**$0.43**
Year 20	$16.03	$14.35	**$30.38**	$0.21	$0.24	**$0.45**
20-Year Total	**$235.19**	**$210.56**	**$445.75**	**$2.63**	**$3.11**	**$5.74**
20-Year NPV	**$115.36**	**$103.28**	**$218.64**	**$1.15**	**$1.36**	**$2.51**

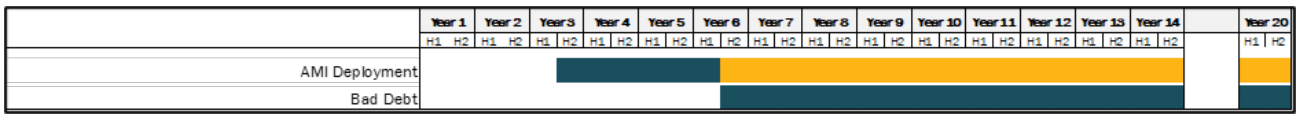
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability				Benefit Realization			
	Number of Customers with Capability (#)	Percent of Customers with Capability (%)	Number of Service Transformers with at Least Two AMI Meters (#)	Percent of Service Transformers with at Least Two AMI Meters (%)	Number of Minor Storm Events (#)	Number of Blue Sky (Phase Wires Down) Events (#)	Estimated Reduced Restoration Costs for Minor Storms Events ($M)	Estimated Reduced Restoration Costs for Blue Sky (Phase Wires Down) Events ($M)
Year 1	0	0%	*	*	5,583	2,939	$0.00	$0.00
Year 2	0	0%	*	*	5,667	2,984	$0.00	$0.00
Year 3	253,767	17%	*	*	5,752	3,028	$0.02	$0.02
Year 4	740,661	50%	*	*	5,838	3,074	$0.06	$0.07
Year 5	1,228,013	83%	*	*	5,926	3,120	$0.10	$0.12
Year 6	1,482,737	100%	*	*	6,015	3,167	$0.13	$0.15
Year 7	1,504,979	100%	*	*	6,105	3,214	$0.13	$0.16
Year 8	1,527,553	100%	*	*	6,197	3,262	$0.14	$0.16
Year 9	1,550,467	100%	*	*	6,290	3,311	$0.14	$0.17
Year 10	1,573,724	100%	*	*	6,384	3,361	$0.15	$0.17
Year 11	1,597,329	100%	*	*	6,480	3,411	$0.15	$0.18
Year 12	1,621,289	100%	*	*	6,577	3,463	$0.16	$0.18
Year 13	1,645,609	100%	*	*	6,676	3,514	$0.16	$0.19
Year 14	1,670,293	100%	*	*	6,776	3,567	$0.17	$0.20
Year 15	1,695,347	100%	*	*	6,877	3,621	$0.17	$0.20
Year 16	1,720,777	100%	*	*	6,981	3,675	$0.18	$0.21
Year 17	1,746,589	100%	*	*	7,085	3,730	$0.19	$0.22
Year 18	1,772,788	100%	*	*	7,191	3,786	$0.19	$0.23
Year 19	1,799,380	100%	*	*	7,299	3,843	$0.20	$0.24
Year 20	1,826,370	100%	*	*	7,409	3,900	$0.21	$0.24

*Eversource does not currently have an existing AMI base

B.7 ENERGY THEFT/WRITE-OFF REDUCTION

(i) <u>Reduced Bad Debt / Write-Offs</u>



a. Description

As described in Section B.1.i. – Meter Reading, the Company's existing AMR infrastructure requires a field technician to physically visit a customer premise to discontinue service, or to investigate potential

instances of unbilled usage. When AMI is implemented, the Company will have the ability to remotely shut off and turn on the power at an individual premise enabling efficiencies in meter-to-cash processes and operations. If combined with a robust customer education effort on the new automated process, the Company would increase the effectiveness of its collections process, lowering costs for all customers.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

The Company estimated reduced bad debt benefits from AMI-enabled Remote Connect/Disconnect ("RCD") by quantifying the incremental improvement in non-payment disconnection execution versus business-as-usual and translating that incremental activity into avoided uncollectible balances. Business-as-usual disconnection volume is based on the Company's annual electric SONP/disconnect target. The post-AMI/RCD case assumes disconnections increase as meters are deployed and RCD is adopted, reaching a steady-state total disconnection rate of 9.1%, or 119,333 annually. The benefit is based on the incremental volume above business-as-usual, adjusted for customer protections using a non-hardship factor.

Avoided bad debt per incremental eligible event is estimated using an average shut off non-payment ("SONP") balance of $350 and a bad debt reserve factor, consistent with Connecticut reconnection requirements. Benefits ramp with deployment and operational adoption; for BCA purposes, realization begins at meter deployment end and ramps to steady state over three years post-deployment.

<u>Annual Benefit Calculations</u>

Business As Usual Reduction in Bad Debt / Write-Offs Calculation:									
Current Annual Electric Disconnects for SONP	X	Average SONP ($)	X	Non-Hardship (%)	X	Bad Debt per $1 of SONP ($)	X	Inflation (%)	
30,538		$350		75%		$0.37		2%	

Post-AMI Deployment Reduction in Bad Debt / Write-Offs Calculation:											
Incremental Annual Electric Disconnects for SONP	X	Average SONP ($)	X	Non-Hardship (%)	X	Bad Debt per $1 of SONP ($)	X	Incremental Benefit Over 3 Years After AMI Deployment Completes	X	Inflation (%)	X	Meter Growth (%)
88,595		$350		75%		$0.37		17%-100%		2%		1.5%

Reduced Bad Debt / Write-Offs List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Current Annual Electric Disconnects for SONP	30,538	2025 Company monthly data	Actual incremental disconnects could increase faster than meter growth which is used as a proxy for future increases
Incremental Annual Electric Disconnects for SONP	88,595	Company data that varies depending on the month and based on dollar threshold	Actual incremental disconnects could increase faster than meter growth which is used a proxy for future increases
Average SONP ($)	$350	2025 Company data	The average SONP is assumed to increase at 2% inflation but could be greater or less
Non-Hardship (%)	75%	2025 Company data	The percent of non-hardship customers in the future could be more or less than the current percent
Bad Debt per $1 of SONP ($)	$0.37	2025 Company data	The bad debt per $1 of SONP could increase or decrease in the future depending on disconnect regulation
Incremental Benefit Over 3 Years After AMI Deployment Completes	17%-100%	Industry benchmarks	Estimated based on current projected meter deployment timeline
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meter growth is used as a proxy for customer growth. Meters could grow greater or less than 1.5%
Inflation (%)	2%	PURA requirement	Inflation may be higher than 2%

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Annual Electric Disconnects for SONP ($)	Incremental Annual Electric Disconnects for SONP ($)
Year 1	$3.03	$0.00
Year 2	$3.09	$0.00
Year 3	$3.15	$0.00
Year 4	$3.21	$0.00
Year 5	$3.27	$0.00
Year 6	$3.34	$1.80
Year 7	$3.41	$5.48
Year 8	$3.48	$9.43

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Annual Electric Disconnects for SONP ($)	Incremental Annual Electric Disconnects for SONP ($)
Year 9	$3.54	$11.76
Year 10	$3.62	$12.17
Year 11	$3.69	$12.60
Year 12	$3.76	$13.05
Year 13	$3.84	$13.51
Year 14	$3.91	$13.99
Year 15	$3.99	$14.48
Year 16	$4.07	$14.99
Year 17	$4.15	$15.52
Year 18	$4.24	$16.07
Year 19	$4.32	$16.63
Year 20	$4.41	$17.22
20-Year Total	**$73.51**	**$188.70**
20-Year NPV	**$37.27**	**$74.54**

d. Data to Track the Availability and Realization of the Benefit

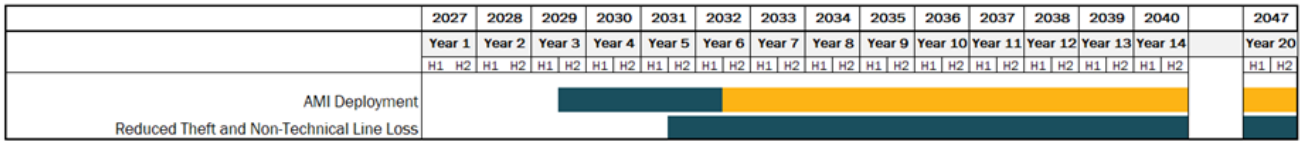
	Benefit Availability	
	Number of Meters Enabled with Remote Disconnect	Percentage of Meters Enabled with Remote Disconnect
Year 1	0	0%
Year 2	0	0%
Year 3	0	0%
Year 4	0	0%
Year 5	0	0%
Year 6	253,767	100%
Year 7	740,661	100%
Year 8	1,228,013	100%
Year 9	1,550,467	100%
Year 10	1,573,724	100%
Year 11	1,597,329	100%
Year 12	1,621,289	100%
Year 13	1,645,609	100%
Year 14	1,670,293	100%
Year 15	1,695,347	100%
Year 16	1,720,777	100%
Year 17	1,746,589	100%
Year 18	1,772,788	100%
Year 19	1,799,380	100%
Year 20	1,826,370	100%

	Benefit Realization					
	Monthly Number of Disconnects	Difference Between Monthly Number of Disconnects and Historical Baseline	Estimated Actual Avoided Bad Debt Based on the Number of Disconnects Compared to Baseline ($M)	Percent Net Write off Compared to Historical Baseline	90 Day Receivables as Percent of Revenue for Hardship Customers	90 Day Receivables as Percent of Revenue for Non-Hardship Customers
Year 1	2,545	0	$0.00	*	*; **	*
Year 2	2,545	0	$0.00	*	*; **	*
Year 3	2,545	0	$0.00	*	*; **	*
Year 4	2,545	0	$0.00	*	*; **	*
Year 5	2,545	0	$0.00	*	*; **	*
Year 6	3,917	1,372	$1.80	*	*; **	*
Year 7	6,642	4,097	$5.48	*	*; **	*
Year 8	9,448	6,903	$9.43	*	*; **	*
Year 9	10,986	8,442	$11.76	*	*; **	*
Year 10	11,113	8,568	$12.17	*	*; **	*
Year 11	11,242	8,697	$12.60	*	*; **	*
Year 12	11,372	8,827	$13.05	*	*; **	*
Year 13	11,504	8,960	$13.51	*	*; **	*
Year 14	11,639	9,094	$13.99	*	*; **	*
Year 15	11,775	9,230	$14.48	*	*; **	*
Year 16	11,914	9,369	$14.99	*	*; **	*
Year 17	12,054	9,509	$15.52	*	*; **	*
Year 18	12,197	9,652	$16.07	*	*; **	*
Year 19	12,342	9,797	$16.63	*	*; **	*
Year 20	12,489	9,944	$17.22	*	*; **	*

*Eversource will continue to report these metrics to PURA as actuals throughout AMI deployment and operation, however due to the number of variables involved, cannot reasonably provide projections for forecasted values

** Eversource has not included any reduced bad-debt benefits from customers with a financial hardship or medical protection.

(ii) <u>Reduced Theft and Non-Technical Line Loss</u>



a. Description

AMI provides the capability to reduce non-technical energy losses, which include theft, equipment failures and other causes. Detecting and resolving additional non-technical energy losses results in a reduction of unbilled revenue benefits.

Non-technical losses are more difficult to detect using current metering technology. Using AMI, more indications of non-technical losses are automatically detected and captured and that information drives high quality leads to investigate. As a result, leveraging granular AMI data, the Company's revenue assurance team will be better able to identify situations where usage is detected, but it is not being billed to a customer at the level being used. For example, the functionality of AMI provides the sum of the individual meter consumption which should equal the measured usage on the network meter feeding those individual meters. Discrepancies between these values will indicate potential non-technical line losses at a higher confidence level than today's capabilities support. AMI data also includes flags and reveal patterns that can indicate tamper or other issues.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

The Company evaluated the business-as-usual average ("BAU") non-technical energy avoided losses on a per case basis over the past few years to determine a baseline amount. The Company expects a material increase in 12-month avoided non-technical losses that will start near the end of the AMI meter deployment given the volume and quality of revenue assurance (RA) leads that that AMI will detect.

Annual Benefit Calculations:

Reduced Non-Technical Line Losses

Business As Usual Reduced Non-Technical Line Losses Calculation:				
BAU Cases that Result in Avoided Losses Annually (#)	X	BAU Revenue Recovered per Case per Year ($)	X	Inflation (%)
154		$5,386		2%

Post-AMI Deployment Reduced Non-Technical Line Losses Savings Calculation:						
Post-AMI Deployment Cases With Non-Technical Line Loss Benefit Annually (#)	X	Post-AMI Deployment Non-Technical Line Loss Benefit from 12-Month Avoided Loss and Revenue Recovered per Case per Year ($)	X	Annual AMI Meters Deployed (%)	X	Inflation (%)
280		$7,500		17%-100%		2%

Reduced Non-Technical Line Losses List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
BAU Average Cases Resolved that Resulted in Avoided Losses (#)	154	2017-2023 annual average RA cases resolved with 2 highly experienced RA investigators (excl. 2020-2021 due to Covid-19)	The BAU average number of cases could increase or decrease in the future
BAU Avoided Losses per Case per Year ($)	$5,386	2017-2023 annual average cases closed resulting in avoided losses (excl. 2020-2021 due to Covid-19 and multi-year outliers)	The BAU revenue recovered per case per years could increase or decrease more than this amount in the future and grow faster or slower than 2% inflation
Post-AMI Average Cases Resolved Annually that Result in Avoided Losses (#)	280	8 incremental field investigators x 35 RA average cases resolved annually estimated to result in avoided losses.	The post-AMI number of cases could be higher or lower than this amount which will impact the annual benefit
Post-AMI Deployment Non-Technical Line Loss Benefit from 12-Month Avoided Loss and Revenue Recovered per Case per Year ($)	$7,500	Estimate ~40% increased value per average RA avoided loss resolved post-AMI compared to BAU based on peer utility insight Pennsylvania and other states.	The 12-month avoided loss and revenue recovered per case per year could be higher or lower than this value and depends on the cases identified by the revenue assurance analytics software and the ability of the revenue assurance investigator to recover the revenue
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

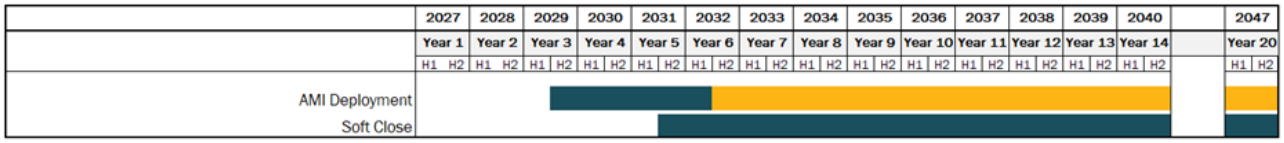
	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Non-Technical Line Loss Total	Non-Technical Line Loss Benefit Total
Year 1	$0.14	$0.00
Year 2	$0.14	$0.00
Year 3	$0.15	$0.00
Year 4	$0.15	$0.00
Year 5	$0.15	$0.33
Year 6	$0.16	$1.18
Year 7	$0.16	$2.00
Year 8	$0.16	$2.46
Year 9	$0.17	$2.51
Year 10	$0.17	$2.56
Year 11	$0.17	$2.61
Year 12	$0.18	$2.66
Year 13	$0.18	$2.72
Year 14	$0.18	$2.77
Year 15	$0.19	$2.83
Year 16	$0.19	$2.88
Year 17	$0.19	$2.94
Year 18	$0.20	$3.00
Year 19	$0.20	$3.06
Year 20	$0.21	$3.12
20-Year Total	**$3.44**	**$39.63**
20-Year NPV	**$1.75**	**$16.46**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability		Benefit Realization		
	Number of Accounts Available for Monitoring (#)	Number of Revenue Assurance Investigators (#)	Difference Between Baseline and Post-AMI Number of Instances of Non-Technical Line Loss Cases Recovered (#)	Number of Instances of Non-Technical Line Loss Cases Recovered with AMI (#)	Avoided Non-Technical Line Losses with AMI ($M)
Year 1	0	2	65	0	$0.00
Year 2	0	2	65	0	$0.00
Year 3	253,767	2	65	0	$0.00
Year 4	740,661	2	65	0	$0.00
Year 5	1,228,013	4	65	48	$0.33
Year 6	1,482,737	7	65	140	$1.18
Year 7	1,504,979	10	65	232	$2.00
Year 8	1,527,553	12	65	280	$2.46
Year 9	1,550,467	12	65	280	$2.51
Year 10	1,573,724	12	65	280	$2.56
Year 11	1,597,329	12	65	280	$2.61

	Benefit Availability		Benefit Realization		
	Number of Accounts Available for Monitoring (#)	Number of Revenue Assurance Investigators (#)	Difference Between Baseline and Post-AMI Number of Instances of Non-Technical Line Loss Cases Recovered (#)	Number of Instances of Non-Technical Line Loss Cases Recovered with AMI (#)	Avoided Non-Technical Line Losses with AMI ($M)
Year 12	1,621,289	12	65	280	$2.66
Year 13	1,645,609	12	65	280	$2.72
Year 14	1,670,293	12	65	280	$2.77
Year 15	1,695,347	12	65	280	$2.83
Year 16	1,720,777	12	65	280	$2.88
Year 17	1,746,589	12	65	280	$2.94
Year 18	1,772,788	12	65	280	$3.00
Year 19	1,799,380	12	65	280	$3.06
Year 20	1,826,370	12	65	280	$3.12

(iii) Reduced Soft Close Loss



a. Description

Another AMI-enabled benefit is related to savings on soft-close scenarios, which occurs when the service remains active after a customer has moved out and before the next customer moves in. Currently, the cost to roll the truck and perform the disconnection and reconnection as customers move in would outweigh the unbilled revenue in some scenarios. In the future with AMI, the system's remote turn-on and turn-off capabilities will significantly reduce costs by allowing the Company to deactivate inactive meters remotely without needing to roll trucks to perform the work, as described in benefit B.3, Automate Service Orders.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Benefit Calculation Methodology

The Company calculated the 3-year average soft close usage of 8,681,929 kWh and estimates that 90% of that amount would be reduced with AMI. This kWh usage was multiplied by the 2022-2025 4-year average R-1 rate of $0.2945 per kWh to determine the incremental benefit from AMI.

Reduced Soft Close Losses

Business As Usual Reduced Soft Close Calculation:							
Annual Soft Close (kWh)	X	2022-2025 4-year Average R-1 Rate ($/kWh)	X	Meter Growth (%)	X	Inflation (%)	
8,681,929		$0.2945		1.5%		2%	

Post-AMI Deployment Reduced Soft Close Savings Calculation:											
Annual Soft Close (kWh)	X	2022-2025 4-year Average R-1 Rate ($/kWh)	X	Reduction of Soft Close Loss (%)	X	Annual AMI Meters Deployed (%)	X	Meter Growth (%)	X	Inflation (%)	
8,681,929		$0.2945		90%		17%-100%		1.5%		2%	

Reduced Soft Close Losses of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual Soft Close (kWh)	8,681,929	3-year average from 2023-2025	Annual soft close amount does not include unidentified usage, which if included could increase the benefit. The amount could increase or decrease faster or slower than meter growth, which is used as a long-term proxy for increase in annual soft close.
2022-2025 4-year Average R-1 Rate ($/kWh)	$0.2945	4-year average R-1 rate	The rate could increase faster or slower than 2% inflation
Reduction of Soft Close Loss (%)	90%	Industry benchmark across several utilities	The reduction in soft close could be higher or lower than 90%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meter growth is a long-term proxy for the increase in annual soft close. Soft close could rise higher or lower than this rate
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meter growth is a long-term proxy for the increase in annual soft close. Soft close could rise higher or lower than this rate

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)	Benefit Targets ($M)
	Baseline Soft Close Loss Total	Soft Close Loss Benefit Total
Year 1	$2.65	$0.00
Year 2	$2.74	$0.00
Year 3	$2.84	$0.00
Year 4	$2.94	$0.00
Year 5	$3.04	$2.28
Year 6	$3.15	$2.83
Year 7	$3.26	$2.93
Year 8	$3.37	$3.04
Year 9	$3.49	$3.14
Year 10	$3.62	$3.25
Year 11	$3.74	$3.37
Year 12	$3.88	$3.49
Year 13	$4.01	$3.61
Year 14	$4.15	$3.74
Year 15	$4.30	$3.87
Year 16	$4.45	$4.01
Year 17	$4.61	$4.15
Year 18	$4.77	$4.30
Year 19	$4.94	$4.45
Year 20	$5.12	$4.60
20-Year Total	**$75.08**	**$57.07**
20-Year NPV	**$36.83**	**$24.34**

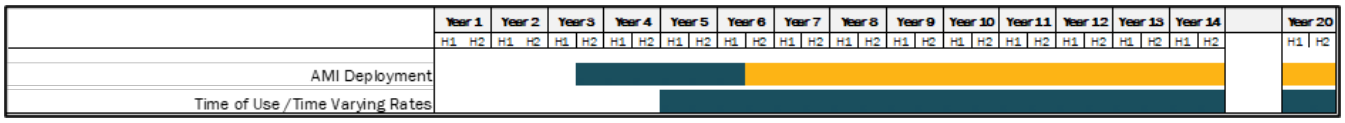
d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability	Benefit Realization		
	Meters Deployed	Baseline Soft Close Loss (MWh)	Soft Close Loss Reduced with AMI (MWh)	Soft Close Loss Avoided Losses ($M)
Year 1	0%	8,812	0	$0.00
Year 2	0%	8,944	0	$0.00
Year 3	0%	9,079	0	$0.00
Year 4	50%	9,215	4,146	$0.00
Year 5	83%	9,353	7,015	$2.28
Year 6	100%	9,493	8,544	$2.83
Year 7	100%	9,636	8,672	$2.93
Year 8	100%	9,780	8,802	$3.04
Year 9	100%	9,927	8,934	$3.14
Year 10	100%	10,076	9,068	$3.25
Year 11	100%	10,227	9,204	$3.37
Year 12	100%	10,380	9,342	$3.49
Year 13	100%	10,536	9,482	$3.61
Year 14	100%	10,694	9,625	$3.74
Year 15	100%	10,854	9,769	$3.87
Year 16	100%	11,017	9,916	$4.01

	Benefit Availability	Benefit Realization		
	Meters Deployed	Baseline Soft Close Loss (MWh)	Soft Close Loss Reduced with AMI (MWh)	Soft Close Loss Avoided Losses ($M)
Year 17	100%	11,183	10,064	$4.15
Year 18	100%	11,350	10,215	$4.30
Year 19	100%	11,520	10,368	$4.45
Year 20	100%	11,693	10,524	$4.60

B.8 CUSTOMER EMPOWERMENT

(i) Time of Use (TOU) /Time Varying Rates (TVR)



a. Description

The interval data made available by AMI meters and enabled through CIS can be leveraged to expand customer choice by providing more advanced rate options, including TOU/TVR to customers. TOUs/TVRs encourage customers to reduce or shift electricity use from high-demand, peak hours to lower demand, off-peak hours and can result in savings on customer electric bills and help reduce peak system loads.

AMI enables incremental benefits to current TOU/TVR offerings. For customers, this data provides critical insights which allow informed decisions about their rates and usage. By assessing their hourly usage profiles customers can determine whether switching to TOU/TVR rates would impact their costs before actually making the switch. These additional data insights will also benefit customers assessing TOU/TVR rate options from competitive suppliers. Customers that make the transition to a TOU/TVR rate will then also be empowered to track and manage their usage to understand the costs or savings from specific behavior changes, the impacts of pricing changes or peak hours, and make informed decisions on how to adjust their usage to control costs.

In addition to providing customers with critical information to assessing TOU/TVR options, the Company will also be able to leverage AMI data to design more detailed or custom-tailored rate options and optimize TOU/TVR outcomes. By analyzing customer load profiles, the Company can determine how designed rates would impact customers and develop rate options that customers would want to select and which will have the most beneficial system outcomes, incentivizing customers to shift load from on to off peak hours. More advanced rate designs, particularly where customers must respond to pricing signals, require customers to have near real-time usage and pricing data, and enhanced billing/settlement capabilities (e.g., MDMS and CIS enablement) to support the additional rate complexity.

In addition to enhancing the Company's rate design capabilities, analysis of AMI data will also allow the Company to better support customers to make informed decisions about rate selection and energy usage. Designing TOU/TVR based on actual customer use and load profiles, system constraints, and generation mixes can result in a variety of TOU/TVR options which can be targeted to different customer segments. The Company will gather input from customers and other stakeholders, as well as findings at other utilities, to determine the desired rate types and structures to implement.

Sharing AMI data with 3rd parties will also enable 3rd party suppliers to offer TOUs/TVRs to their customers, and provide additional value-added services by sharing data with other 3rd parties, such as renewable energy suppliers. This benefit is considered a customer savings benefit, meaning that the value is realized directly by customers, either through reduced billing costs or improved reliability. Separately, recent legislation (SB4) directs the Company to implement changes to current TOU/TVR rates to achieve specific policy objectives; "first-generation" enhancements may be achievable without AMI (as demonstrated by recently implemented advanced rate design examples). AMI would, relative to these updated "current" rates, enable the Company to pursue even more advanced rate designs that depend on interval data and associated system capabilities. The BCA quantifies the potential future incremental benefits associated with those AMI-enabled advanced rate options.

b. Benefit Calculation Methodology

Some of the initial TOU/TVR planning work has already been started prior to the start of AMI program implementation. These activities include a pilot program to review TVR rate structures and advanced rate design planning. TOU/TVR rate enablement is expected to start in 2028 following the stabilization of core meter-to-cash processes and after the initial AMI change management with customers is demonstrated to be successful. TOU/TVR capabilities are expected to be enabled on a phased basis, beginning approximately one year after initial AMI installation. The Company will require several months to collect and analyze real-time customer usage enabled by AMI to better inform TOU rate design. This will be followed by a structured process to develop TOU/TVR rate designs, incorporate stakeholder input, and obtain regulatory approval from the Public Utilities Regulatory Authority ("PURA").

In advance of TOU enrollment, the Company will implement a customer education and marketing campaign to inform customers of available rate options and explain how they may benefit based on their usage patterns and ability to shift load.

The quantitative benefit of TOUs/TVRs to customers is calculated based on an expected customer adoption rate of 3.6% for C&I customers and 6.0% for residential customers. These adoption rates were based on previous pilots and industry benchmarks. The anticipated demand reduction benefits were estimated to be about 12% for residential and 3.6% for C&I customers and were multiplied by the on-peak demand for these rate classes to understand the total demand reduction anticipated across the system. This reduction was then multiplied by the AESC capacity cost ($52,000/kW) and T&D capacity cost ($69,000/kW) to calculate the total financial benefit for each customer class.

It is important to note that these benefits are highly sensitive to customer adoption; therefore, the range of potential outcomes is wide.

Annual Benefit Calculations:

Business As Usual Residential TOU Demand Cost Calculation:								
AESC Capacity Cost ($/kW)	+	AESC T&D Capacity Cost ($/kW)	X	Residential On-Peak Demand (MW)	X	Demand Growth (%)	X	Inflation (%)
$52,000		$69,000		2,441		0.6%		2%

Post-AMI Deployment Residential TOU Demand Benefit Calculation:													
AESC Capacity Cost ($/kW)	+	AESC T&D Capacity Cost ($/kW)	X	Residential On-Peak Demand (MW)	X	Residential Customer Participation (%)	X	Residential Demand Reduction (%)	X	Annual AMI Meters Deployed (%)	X	Demand Growth (%)	X	Inflation (%)
$52,000		$69,000		2,441		6.0%		12%		17%-100%		0.6%		2%

Business As Usual C&I TOU Demand Cost Calculation:								
AESC Capacity Cost ($/kW)	+	AESC T&D Capacity Cost ($/kW)	X	C&I On-Peak Demand (MW)	X	Demand Growth (%)	X	Inflation (%)
$52,000		$69,000		2,426		0.6%		2%

Post-AMI Deployment C&I TOU Demand Benefit Calculation:													
AESC Capacity Cost ($/kW)	+	AESC T&D Capacity Cost ($/kW)	X	C&I On-Peak Demand (MW)	X	C&I Customer Participation (%)	X	C&I Demand Reduction (%)	X	Annual AMI Meters Deployed (%)	X	Demand Growth (%)	X	Inflation (%)
$52,000		$69,000		2,426		3.6%		3.6%		17%-100%		0.6%		2%

Time of Use/Time Varying Rates List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
AESC Capacity Cost ($/kW)	$52,000	Connecticut value from 2024 AESC Report	Inflation is a long-term proxy for the energy rate increase and the actual future value could increase or decrease more than this amount
AESC T&D Capacity Cost ($/kW)	$69,000	Connecticut value from 2024 AESC Report	Inflation is a long-term proxy for the energy rate increase and the actual

Time of Use/Time Varying Rates List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
			future value could increase or decrease more than this amount
Residential On-Peak Demand (MW)	2,441	2023 Company data	Meter growth is a long-term proxy for residential peak demand (MW) increase and peak demand could increase faster than this rate
Residential Demand Reduction (%)	12%	Past assumption and industry benchmark	Actual C&I demand reduction and participation could be more or less than these amounts depending on program design and rate structures
Residential Customer Participation (%)	6.0%	Past assumption and industry benchmark	
C&I On-Peak Demand (MW)	2,426	2023 Company data	Meter growth is a long-term proxy for C&I peak demand (MW) increase and peak demand could increase faster than this rate
C&I Customer Participation (%)	3.6%	Past assumption and industry benchmark	Actual C&I demand reduction and participation could be more or less than these amounts and depend on a variety of factors
C&I Demand Reduction (%)	3.6%	Past assumption and industry benchmark	
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5 and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Demand Growth (%)	0.6%	Estimate based on historical and projections	Demand could grow greater or less than 0.6%

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

	Business As Usual ($M)			Benefit Targets ($M)		
	Baseline Residential Energy Demand	Baseline C&I Energy Demand	Baseline Total	Residential Energy Demand Benefit From TOU	C&I Energy Demand Benefit From TOU	Benefit Total
Year 1	$303.14	$301.26	**$604.40**	$0.00	$0.00	**$0.00**
Year 2	$311.08	$309.15	**$620.24**	$0.00	$0.00	**$0.00**
Year 3	$319.23	$317.26	**$636.49**	$0.00	$0.00	**$0.00**
Year 4	$327.60	$325.57	**$653.17**	$0.00	$0.00	**$0.00**
Year 5	$336.19	$334.10	**$670.29**	$2.02	$0.36	**$2.38**
Year 6	$345.00	$342.86	**$687.86**	$2.48	$0.44	**$2.93**
Year 7	$354.04	$351.84	**$705.88**	$2.55	$0.46	**$3.01**
Year 8	$363.32	$361.06	**$724.38**	$2.62	$0.47	**$3.08**
Year 9	$372.84	$370.53	**$743.37**	$2.68	$0.48	**$3.16**
Year 10	$382.61	$380.24	**$762.85**	$2.75	$0.49	**$3.25**
Year 11	$392.64	$390.20	**$782.84**	$2.83	$0.51	**$3.33**
Year 12	$402.93	$400.43	**$803.36**	$2.90	$0.52	**$3.42**
Year 13	$413.49	$410.92	**$824.41**	$2.98	$0.53	**$3.51**
Year 14	$424.32	$421.69	**$846.01**	$3.06	$0.55	**$3.60**
Year 15	$435.44	$432.74	**$868.19**	$3.14	$0.56	**$3.70**
Year 16	$446.86	$444.08	**$890.94**	$3.22	$0.58	**$3.79**
Year 17	$458.57	$455.72	**$914.29**	$3.30	$0.59	**$3.89**
Year 18	$470.58	$467.67	**$938.25**	$3.39	$0.61	**$3.99**
Year 19	$482.92	$479.92	**$962.84**	$3.48	$0.62	**$4.10**
Year 20	$495.57	$492.50	**$988.07**	$3.57	$0.64	**$4.21**
20-Year Total	**$7,838.36**	**$7,789.75**	**$15,628.11**	**$46.95**	**$8.40**	**$55.35**
20-Year NPV	**$3,921.12**	**$3,896.80**	**$7,817.92**	**$20.27**	**$3.63**	**$23.90**

d. Data to Track the Availability and Realization of the Benefit

	Benefit Availability			
	Number of Residential Customers TOU Rates are Available to (#)	Percentage of Residential Customers TOU Rates are Available to (%)	Number of C&I Customers TOU Rates are Available to (#)	Percentage of C&I Customers TOU Rates are Available to (%)
Year 1	0	0%	0	0%
Year 2	0	0%	0	0%
Year 3	215,595	17%	20,709	17%
Year 4	656,487	50%	63,059	50%
Year 5	1,110,690	83%	106,688	83%
Year 6	1,352,794	100%	129,944	100%
Year 7	1,373,086	100%	131,893	100%
Year 8	1,393,682	100%	133,871	100%
Year 9	1,414,587	100%	135,879	100%
Year 10	1,435,806	100%	137,918	100%

	Benefit Availability			
	Number of Residential Customers TOU Rates are Available to (#)	Percentage of Residential Customers TOU Rates are Available to (%)	Number of C&I Customers TOU Rates are Available to (#)	Percentage of C&I Customers TOU Rates are Available to (%)
Year 11	1,457,343	100%	139,986	100%
Year 12	1,479,203	100%	142,086	100%
Year 13	1,501,391	100%	144,217	100%
Year 14	1,523,912	100%	146,381	100%
Year 15	1,546,771	100%	148,576	100%
Year 16	1,569,972	100%	150,805	100%
Year 17	1,593,522	100%	153,067	100%
Year 18	1,617,425	100%	155,363	100%
Year 19	1,641,686	100%	157,693	100%
Year 20	1,666,312	100%	160,059	100%

	Benefit Realization (1 of 2)					
	Residential TOU Rate Participation (%)	C&I TOU Rate Participation (%)	Residential Demand Reduction Compared to Baseline (MW)	C&I Demand Reduction Compared to Baseline (MW)	Residential TOU Retention Rate (%)	C&I TOU Retention Rate (%)
Year 1	6.0%	3.6%	0.00	0.00	*	*
Year 2	6.0%	3.6%	0.00	0.00	*	*
Year 3	6.0%	3.6%	0.00	0.00	*	*
Year 4	6.0%	3.6%	0.00	0.00	*	*
Year 5	6.0%	3.6%	15.10	2.70	*	*
Year 6	6.0%	3.6%	18.23	3.26	*	*
Year 7	6.0%	3.6%	18.34	3.28	*	*
Year 8	6.0%	3.6%	18.45	3.30	*	*
Year 9	6.0%	3.6%	18.56	3.32	*	*
Year 10	6.0%	3.6%	18.68	3.34	*	*
Year 11	6.0%	3.6%	18.79	3.36	*	*
Year 12	6.0%	3.6%	18.90	3.38	*	*
Year 13	6.0%	3.6%	19.02	3.40	*	*
Year 14	6.0%	3.6%	19.14	3.42	*	*
Year 15	6.0%	3.6%	19.25	3.44	*	*
Year 16	6.0%	3.6%	19.37	3.46	*	*
Year 17	6.0%	3.6%	19.49	3.49	*	*
Year 18	6.0%	3.6%	19.61	3.51	*	*
Year 19	6.0%	3.6%	19.72	3.53	*	*
Year 20	6.0%	3.6%	19.84	3.55	*	*

*Retention rate would be determined as part of advanced rate design plan within the AMI Plan.

	Benefit Realization (2 of 2)					
	Total Residential Customer Savings Realized ($M)	Total C&I Customer Savings Realized ($)	Total Residential Customer TOU Enrollment (#)	Total C&I Customer TOU Enrollment (#)	Per Capita Residential Customer Savings Realized ($)	Per Capita C&I Customer Savings Realized ($)
Year 1	$0.00	$0.00	0	0	$0.00	$0.00
Year 2	$0.00	$0.00	0	0	$0.00	$0.00
Year 3	$0.00	$0.00	0	0	$0.00	$0.00
Year 4	$0.00	$0.00	0	0	$0.00	$0.00
Year 5	$2.02	$0.36	66,641	3,841	$30.27	$93.95
Year 6	$2.48	$0.44	81,168	4,678	$30.60	$94.99
Year 7	$2.55	$0.46	82,385	4,748	$30.94	$96.04
Year 8	$2.62	$0.47	83,621	4,819	$31.28	$97.10
Year 9	$2.68	$0.48	84,875	4,892	$31.63	$98.17
Year 10	$2.75	$0.49	86,148	4,965	$31.98	$99.25
Year 11	$2.83	$0.51	87,441	5,040	$32.33	$100.35
Year 12	$2.90	$0.52	88,752	5,115	$32.69	$101.46
Year 13	$2.98	$0.53	90,083	5,192	$33.05	$102.58
Year 14	$3.06	$0.55	91,435	5,270	$33.41	$103.71
Year 15	$3.14	$0.56	92,806	5,349	$33.78	$104.85
Year 16	$3.22	$0.58	94,198	5,429	$34.16	$106.01
Year 17	$3.30	$0.59	95,611	5,510	$34.53	$107.18
Year 18	$3.39	$0.61	97,045	5,593	$34.91	$108.37
Year 19	$3.48	$0.62	98,501	5,677	$35.30	$109.56
Year 20	$3.57	$0.64	99,979	5,762	$35.69	$110.77

(ii) Customer Targeting for Incentives

a. Description

Data provided through the implementation of AMI will provide more detailed information about customer loads and usage patterns. In this BCA, the Company proposes to use this data to assess and implement advanced rates such as TOU/TVR described in Section B.8.i. – TOU/TVR. The implementation of these rates, and outreach to customers who would benefit from them, is expected to realize similar demand benefits to customer targeting for programs such as energy efficiency and demand response, where such benefits might exist. Furthermore, increasing customer participation for energy efficiency and demand response programs would require increased costs to incentivize new participants beyond the program's current capacity, with no guaranteed benefit.

Our nation-leading energy efficiency and other customer-facing programs use extensive data analytics and customer targeting approaches. Availability of granular AMI data further enhances the ability to target customers. However, increased customer participation will also lead to an overall increase in incentives provided to all customers. Therefore, we chose not to include this as an explicit benefit in the cost-benefit model, even though we believe it provides benefit to customers.

The Company is not contemplating any benefits from customer targeting for incentives.

b. Benefit Calculation Methodology

The Company does not project quantifiable benefits from customer targeting for incentives and thus has not included a benefit calculation methodology.

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

The Company is not contemplating any benefits from customer targeting for incentives benefits and thus has not included business-as-usual costs, benefit targets, and annual benefit calculation.

d. Data to Track the Availability and Realization of the Benefit

As noted above, the Company does not anticipate Benefit Realization tied to Customer Targeting for Incentives and does not have a forecasted Benefit Realization Schedule.

B.9 CUSTOMER SATISFACTION

(i) Improved Reliability

a. Description

Interruptions in electric power service pose significant inconvenience for residential, commercial, and industrial customers. Although the value of reliability to customers varies based on the individual customer and the duration of the outage, it is possible to conduct a high-level strategic estimate of the average monetary value that residential and commercial customers place on averting an outage. These customer benefits are incremental to the benefits of avoided outages. The improved reliability benefit is described and accounted for in Section B.5.i. – Advanced Engineering Analysis, Section B.6.i. – Improved Restoration Significant Storms, and Section B.6.ii. – Improved Restoration - Blue Sky.

AMI is expected to reduce the duration of major outage events by supporting earlier identification and faster restoration of outages. In addition to the cost savings associated with a shorter restoration, the Company recognizes that the customers for whom power is restored more quickly than it would have been without AMI will place a value on that benefit.

Please see Section XI Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit

b. Benefit Calculation Methodology

The calculation methodology and assumptions for improved reliability benefits have been included in Section B.5.i. – Advanced Engineering Analysis, Section B.6.i. – Improved Restoration Significant Storms, and Section B.6.ii. – Improved Restoration – Blue Sky.

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

Business as Usual, Benefit Targets, and Annual Benefit Calculations for Improved Reliability benefits have been included in Section B.5.i. – Advanced Engineering Analysis, Section B.6.i. – Improved Restoration Significant Storms, and Section B.6.ii. – Improved Restoration - Blue Sky.

d. Data to Track the Availability and Realization of the Benefit

Availability and Realization tracking metrics for improved reliability benefits have been included in Section B.5.i. – Advanced Engineering Analysis, Section B.6.i. – Improved Restoration Significant Storms, and Section B.6.ii. – Improved Restoration - Blue Sky.

(ii) Billing Accuracy and Timeliness

a. Description

Traditional estimated billing often leads to customer dissatisfaction and costly disputes when monthly bills fail to accurately reflect actual energy usage. Dependence on usage estimation and manual data collection introduces delays in data transmission and processing, increasing the risk of inaccuracies and the need for rebilling. Currently, the Company achieves a high read rate with its existing AMR meter reading technology, resulting in minimal bill estimation. Consequently, there is no significant difference in billing accuracy between AMR and AMI, and thus the Company has not quantified these benefits in this BCR Report. However, AMI offers automated, granular data collection and, once stable, enables more efficient reading both within and outside the normal billing cycle compared to AMR.

The Company is not contemplating any benefits from Billing Accuracy and Timeliness.

b. Benefit Calculation Methodology

The Company is not contemplating any benefits from Billing Accuracy and Timeliness and thus has not included a benefit calculation methodology.

c. Business-As-Usual Costs, Benefit Targets, and Annual Benefit Calculation

The Company is not contemplating any benefits from Billing Accuracy and Timeliness and thus has not included business-as-usual costs, benefit targets, and annual benefit calculation.

d. Data to Track the Availability and Realization of the Benefit

As noted above, the Company does not anticipate benefit realization tied to Billing Accuracy and Timeliness and does not have a forecasted benefit realization schedule

C. NON-QUANTIFIED BENEFITS

In addition to the benefits quantified in this BCA Report, the Company also identified the following non-quantified benefits that are expected to be realized through the proposed AMI deployment, which may be challenging to be quantified. Since these benefits cannot be quantified, the sections for benefit calculation methodology and business-as-usual costs, benefit targets, and annual benefit calculation have not been included.

C.1 CUSTOMER SATISFACTION

(i) Outage Restoration Notifications

a. Description

With the availability of accurate, timely information on the existence of customer outages, the Company will no longer be reliant on customer calls to inform them of outages and restoration, and the Company will be able to increase the timeliness of customer notifications surrounding restoration work. This has the potential to improve outage notification performance, customer experience, and enable customers to gain outage information through the channel of their choice (e.g., phone, website, mobile app, or IVR).

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from outage restoration notifications will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.2 CUSTOMER EMPOWERMENT AND SYSTEM UTILIZATION

(i) More Accurate Load Profiles

a. Description

As described in Section B.5.i. - Advanced Engineering Analytics, AMI will support quantifiable benefits in proactively reducing the number of distribution transformer overloads through better forecasting. The use of AMI in engineering analysis and system planning, however, has many additional sources of value that are hard to quantify. The value of AMI to engineering and planning is driven by access to sub-hourly load shapes for all customers. Compared to having one total consumption value for a month and assuming an average usage profile over all hours, AMI uncovers the differences between customers with different usage drivers over the course of a day as well as differences in seasonal usage patterns. Access to AMI data, for instance, will help system planners identify the impact of charging of electric vehicles in a specific portion of a circuit or the impact of charging and discharging

behavior resulting from behind-the-meter energy storage. These capabilities will better enable the Company to identify optimal and targeted planning solutions from a wider range of options that include non-wires alternatives ("NWA") and other innovative approaches where applicable.

With respect to medium to long term planning, AMI data can be used to increase the granularity of load forecasting. As opposed to allocating load based on averages, planners will be able to recognize and incorporate usage patterns to improve the accuracy of load flow models. A customer who charges their electric vehicle in the early morning should be modeled differently than a customer whose load is driven by heating technology such as an air-source heat pump. Analysis of AMI data can enable planners to characterize customers' usage by key drivers and allocate load appropriately. This classification will support more robust scenario analysis to determine the potential impact of differing penetration levels of customer-side technologies such as solar, energy storage and electric vehicle charging.

This data will also enable probabilistic system analysis, a key cornerstone to preparing system planning for high DER penetration levels. By providing detailed load shape information, as well as adoption information of new technologies such as electric vehicles, probabilistic system planning enables a more efficient system capacity planning to take place. Furthermore, it enables, through the modelling of randomized customer response, an improved understanding of the potential impact of policies and programs, such as time varying rates, demand response or electric vehicle managed charging, on system load flows. The primary benefits of more accurate medium to long term planning include improved identification and prioritization of necessary distribution system upgrades, increased confidence in NWA identification and improved calculation accuracy for deferred investments.

The secure sharing of more granular usage data with customers and third parties is expected to create additional opportunities for growth in customer-side technologies, load management and innovative third-party solutions. AMI data will enable the impacts of customer choices and investments to be better captured in system planning processes to identify optimal engineering solutions that complement customer-side technologies as part of a modern electrical power system. However, many opportunities for utilizing AMI data will remain within the scope of system planning and investment activity of the regulated distribution company, as discussed above. The removal of forecasting, planning and NWA procurement responsibilities from the utility in the course of AMI deployment is not recommended and utility control of customer and grid data will remain critically important to protect utility customers and limit access to grid weaknesses and vulnerabilities. Management of AMI data consistent with utility obligations to plan and operate a safe, reliable, and secure grid should not be misconstrued to be actions intended to favor or bias EDC solutions against third parties and market-based solutions.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from more accurate load profiles will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.3 OPERATIONAL AND CUSTOMER SATISFACTION

(i) Validate Resilience and Reliability Measures

a. Description

Measuring and analyzing reliability performance is a critical activity to ensure the Company makes cost-effective improvements in the service provided to customers. Using information on the historical frequency and duration of outages at all locations on the grid, the Company identifies investments that maximize reliability. Improvements in the accuracy and effectiveness of reliability analysis resulting from the availability of AMI data have the potential to deliver meaningful benefits to the value of distribution system investments.

Currently it is a manual and time-consuming process to analyze the customer benefit of distribution automation schemes; Engineers use historical data to optimize device location, but it is difficult to track the actual benefit customers experience based on when switch events occur in the field. Integration of AMI data into OMS, in coordination with data from the Company's Energy Control System ("ECS"), will enable engineers to better evaluate the reliability improvement of distribution automation switches to inform improved decisions going forward.

The use of AMI data can also improve reliability analysis and decision making through measurement of momentary outages. Currently, the Company tracks a sustained customer outage as loss of supply lasting five minutes or longer. These shorter duration events are increasingly impactful for customers. Modern electronic equipment is often sensitive to short power interruptions. This is particularly true for commercial and industrial customers where momentary outages can cause costly disruptions in production lines and other operations. Deployment of devices that automatically isolate faults and re-feed unaffected sections has had a significant benefit in terms of averting sustained outages but each of these operations results in momentary outages for large numbers of customers.

Using AMI data, the Company will be able to track each time a customer has an outage lasting less than five minutes. This will enable calculation of the industry-standard measure of the frequency of momentary outages, momentary average interruption frequency index ("MAIFI"). This information will enable prioritization of measures to reduce momentary outages, including mitigations such as equipment selection and operating guidelines for distribution automation schemes.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from validating resilience and reliability measures will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.4 OPERATIONAL

(i) Integrating AMI Data with System Operations Center

a. Description

Integration of AMI data into the Company's OMS will drive quantifiable benefits for reduced significant storm costs and reliability benefit for customers. There are multiple, future, and hard to quantify benefits of AMI for the Company's real time system operations center.

Investments in control room capabilities have the potential to integrate AMI data to improve the sophistication of near-term forecasting, combining weather forecasts into a system model that allocates load at the customer level. More granular insight into load and generation dynamics at the customer level enabled by AMI will improve the effectiveness of forecasts down to the circuit segment level. System operators will have more insight into potential overload conditions at peak conditions or day-time minimum. Integration of AMI data into the Company's OMS will further drive quantifiable benefits for reduced significant storm costs and reliability benefits for customers.

As the complexity of the distribution system continues to increase, the Company's system operations center will need to incorporate a real-time load flow model to support all switching and automation activities. This DMS will incorporate real-time telemetry available in the Company's energy control system ("ECS") with the physical characteristics and settings of distribution equipment to create a model that provides visibility into power flows allocated down to the distribution transformer level. The availability of AMI data will greatly improve load allocations at the customer level by using the AMI data at regular intervals to validate the DMS load flow, and make adjustments as needed, increasing the accuracy of the DMS load flow calculations. The benefits of an improved DMS load flow include enhanced situational awareness, providing operators with better insight into loading before and after an outage event, addressing issues such as cold load pick-up and the impact of solar facilities coming back on-line. An improved DMS load flow will also increase the accuracy of fault location calculations, leading to a further improvement in reliability for customers.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from integrating AMI data with the system operations center will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.5 SAFETY

(i) Public Safety and Downed Wires

a. Description

Detecting and repairing live, downed conductors is the primary responsibility of the company's system operations center and emergency response organization. Downed conductors are the priority in storm response. In medium and significant storm events with multiple trouble spots and high call volumes, identification and prioritization of all downed conductors can be a challenge. During these events traditional methods of identification, including data from customer calls and the power flows in the Company's ECS, can be overwhelmed and fail to identify a downed conductor location.

An emerging value proposition for AMI data is its use to detect the location of a high impedance fault. In situations where protection schemes cannot determine a fault condition and trip, high voltages in conductors resulting from a high impedance fault are a source of concern for public safety that must be identified and repaired immediately. The availability of voltage measurements from AMI along a feeder, combined with detection algorithms, can support identification of these types of faults. Calculating, identifying, and alarming for conditions indicating the location of a high impedance fault has the potential to provide a significant safety benefit for the general public. The cost associated with this benefit is detailed in Section D.5.i. - Engineering and Customer Usage Analytics.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from public safety and downed wires will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.6 EFFICIENCY

(i) Shared AMI Systems Across Affiliates

a. Description

Eversource expects that deployment of an AMI system for Connecticut electric customers will have benefits for Eversource affiliates. The implementation of a communications network capable of transmitting meter and sensor data to and from all electric residential and commercial meters in Connecticut has the potential to be leveraged by the company's gas affiliate in Connecticut. Currently, Eversource Connecticut gas meters are read by a drive-by AMR system. Eversource expects to design a communications network that could also be used to support gas AMI and modern gas sensing capabilities, such as methane detection for safety and cathodic protection systems to address gas leaks. Advances in gas smart meter technology, including remote disconnect for safety purposes, are increasing the value proposition of transitioning away from current meter technology. Almost 60 percent of gas meters and infrastructure overlap with the electric service territory.

Additional synergies may arise related to the cost and benefits associated with major back-office systems. Eversource has long recognized the value associated with designing enterprise IT systems to support all affiliate transactions, namely reducing total implementation costs, including resources required for planning and procuring the vendor solution. The Company is also in a better position to negotiate lower cost licenses and ongoing maintenance and support services. Benefits of using one system across affiliates related to training and consistent processes have been identified as well. The Company's enterprise OMS, for instance, is used by all electric companies enabling trained users to seamlessly support restoration efforts in any state. The Company expects gas and electric affiliates will transition to the same enterprise MDMS and CIS as the one selected to support the Massachusetts electric AMI deployment.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from shared AMI systems across affiliates will become fully available only after the deployment has been completed for electric customers and gas customers as well, if such future scope is proposed and approved. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

C.7 CUSTOMER ENGAGEMENT

(i) Detailed Billing Data and Notifications

a. Description

Access to granular, near–real-time billing and usage data will benefit customers by enabling actionable insights, secure third-party data sharing, and customized usage alerts. Customers can better

understand and manage consumption, adjust behavior sooner, and reduce bill volatility and rate shock. Usage data will be available in 15-minute intervals within 24–48 hours and retained for at least 24 months, enabling customer service representatives and digital tools to provide more targeted recommendations, including time-varying rates and energy efficiency or demand response programs.

Customers will be able to view their usage through the Eversource website and securely share it with authorized third parties. AMI data will be available via existing methods and may be supported by additional data-sharing mechanisms in future years. For example, customers may authorize their competitive electric power supplier ("CEPS") or other service providers to access monthly, daily, and interval data; approved CEPS can download current usage, demand, and interval data, along with up to 24 months of historical information.

Building on existing bill and payment alerts (which occur after billing), the Company will offer optional usage alerts delivered during the billing cycle – via email, text, and mobile app notifications—to flag unusual consumption (higher or lower) sooner. Customers will be able to set personalized thresholds for alerts, and the Company may also proactively establish high-bill alert thresholds based on a customer's historical usage, with the ability to adjust preferences, manage contact information, or opt out. More frequent AMI data also enables more timely, customer-specific insights (e.g., hourly/daily/weekly patterns) and relevant recommendations, including a residential rate calculator to show how different rates or programs could impact bills based on a customer's actual usage.

The Company's outbound, customer-specific energy insights are driven by usage data. Today, insights such as year-over-year comparisons and seasonal summaries rely on monthly data; AMI enables deeper analysis at the hourly, daily, and weekly levels to deliver more relevant recommendations more quickly. Residential customers will also have access to a rate calculator to understand how different rates or programs may affect their bills based on their usage patterns, and they can opt into energy insights and high-bill alerts via email, text, or mobile app notifications. Customers can set their own alert thresholds, and the Company may also establish default thresholds based on historical usage, with options to adjust preferences, manage contact information, or opt out.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from detailed billing data and notifications will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

(ii) Load Disaggregation

a. Description

AMI offers the powerful capability of load disaggregation, which significantly enhances customers' understanding of their energy usage patterns. Load disaggregation involves breaking down total energy consumption into specific categories, such as heating, cooling, lighting, and appliance usage. This detailed breakdown provides customers with precise insights into the drivers of their energy consumption, enabling them to make informed decisions about their energy use. The granular visibility afforded by AMI allows customers to identify inefficiencies and understand the specific contributors to their energy bills, thereby promoting more efficient energy use.

Without AMI, traditional meters typically collect data in an aggregate form that lacks the necessary granularity for effective load disaggregation. This limitation prevents customers from receiving detailed insights into their energy usage, hindering their ability to identify areas that significantly drive their energy consumption. The continuous, real-time consumption data provided by AMI empowers customers to optimize their energy use by making data-driven decisions. Overall, the detailed consumption data facilitated by AMI through load disaggregation not only promotes energy efficiency but also strengthens the relationship between the utility and its customers by fostering transparency and trust.

Please see Section IX Appendix for a list of the Necessary AMI Infrastructure and O&M Costs associated with this benefit.

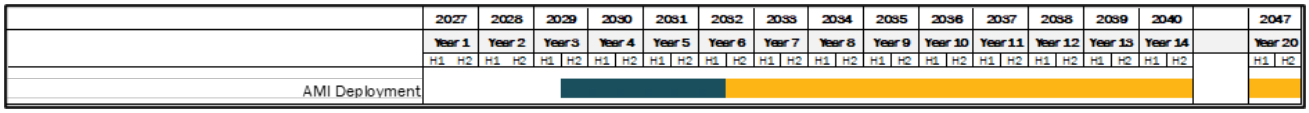
b. Data to Track the Availability and Realization of the Benefit

The Company expects that customer benefits from load disaggregation will become fully available once the deployment has been completed for the necessary infrastructure costs listed above. Since this benefit has not been quantified, data is not available for more detailed tracking of the availability or realization of this benefit.

D. COSTS

D.1 METER

(i) Meters



a. Description

Across the United States, AMI meters are the foundational investment required to enable the use cases described in this BCA Report. The first AMI meters were deployed in 2006, with a major surge in deployment starting in 2009, as part of the $3.4 billion-dollar Smart Grid Investment Grant ("SGIG")

program funded by the ARRA. The SGIG program concluded in 2015, with 70 AMI deployment projects totaling over 16.3 million AMI meters. Due to limitations in the hardware capabilities of the meters at that time, business cases for these projects focused on providing benefits by reducing meter reading costs, enhanced outage detection, and shifting demand via time-varying rates. AMI deployments have continued to date and currently over 80% of meters in the United States are AMI meters.

Beginning in 2016, the Company launched the Remote Disconnect Project to replace a portion of its hard-to-reach meters with a goal of increasing operational savings and decreasing the amount of customer write-offs and bad debt that are paid for by all other customers. The Company partnered with a vendor to develop and purchase AMR meters with the remote turn-on and turn-off capability through the existing meter reading system. These meters are referred to as "bridge" meters, given they can potentially be switched to AMI mode if a compatible wireless mesh network is available. Due to the success of the Remote Disconnect Project, the Company migrated to the bridge meters as its "meter of choice" for meter replacements in Connecticut.

The newer generation of AMI meters have functionality that was not available through the early bridge meters deployed in the Company's service territory. Advances in the industry throughout the previous decade have enabled additional capabilities in AMI meters at a similar cost, increasing the relative cost-effectiveness. Modern AMI meters now leverage advancements in mesh network technology and 4G LTE and 5G communication technologies, enabling near real-time data sharing through device-to-device communication. This facilitates greater situational awareness for the utility. Equipped with more powerful processors and expanded storage, these meters can download applications and run analytical algorithms to address various use cases, such as mapping meters to transformers and providing customers with detailed insights into their energy usage.

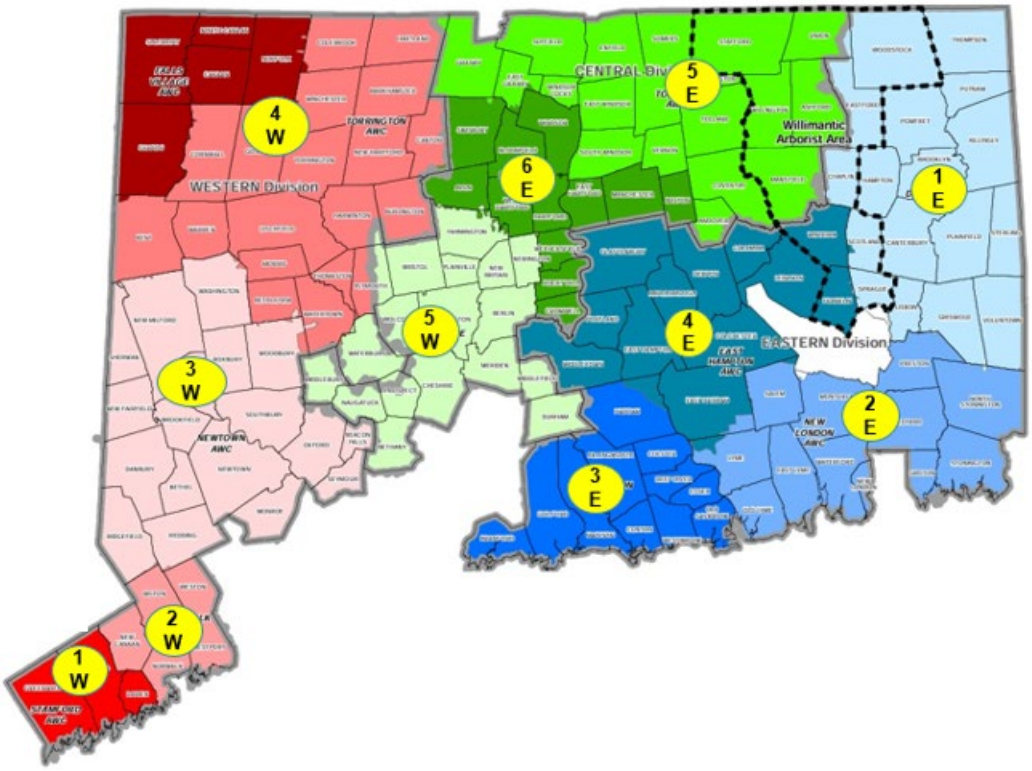
Additionally, modern AMI meters are capable of grid-edge computation, processing vast amounts of data to produce actionable insights for both the customers and the grid. Additional application licensing is required to realize this functionality and the associated costs are detailed in Section D.5.i. - Engineering and Customer Usage Analytics. They can autonomously decide which data to send back to the utility, optimizing network utilization and reducing the amount of time needed to process, analyze, and make decisions based on that data. Advanced AMI use cases now include neutral monitoring, connectivity model verification, and advanced load disaggregation, alongside traditional capabilities such as remote connect/disconnect, internal metering, tamper detection, and power loss and restoration notifications.

To maximize the benefits enabled by AMI, and to ensure all customers have equal access to the latest benefits, the Company is proposing to replace all AMR and bridge meters with state-of-the-art AMI 2.0 meters.

While the detailed deployment sequence will be finalized once vendors are onboarded, the map below illustrates a hypothetical AMI deployment approach. It assumes an initial ramp-up in Region 1E for Meter Installation Vendor ("MIV") hiring, training, and system validation, followed by parallel East/West

deployment teams to balance rural and metro work and maintain steady progress over the three-year rollout. A post-deployment period for optimization and remediation will follow.

Figure 9 – Proposed Deployment Sequence



Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

In 2023, the Company issued a request for proposals ("RFP") to the six leading AMI vendors in the United States. The RFP invited vendors to offer their perspectives and unique solutions that can drive additional value from an AMI deployment to the Company's electric customers and the broader enterprise. The proposed solutions had to be in alignment with the Company's Grid Modernization vision to continuously improve its customers' engagement, safety, security, and reliability in a cost effective and prudent manner. The vendor responses included estimated costs in several categories including meters, installation labor, communications costs (e.g., equipment and service), software licensing fees and maintenance. For cost calculations, the updated cost model uses actual contract data from the selected vendors supporting the on-going Massachusetts AMI Program. Conversely, the 2021 AMI Straw Proposal submitted to PURA was prepared utilizing pre-pandemic industry standards with data points and estimates from a now out-of-date request for information ("RFI").

The cost model assumes all current 1,356,026 meters (as of this writing) plus all new meter installations between now and AMI deployment will be replaced over a three-year period, including replacement of the 436,246 bridge meters to ensure that no customers are deprived of the state-of-the-art AMI technology features. The costs also include ongoing meter replacements based on a yearly anticipated AMI replacement rate of 0.5% per year and 1.5% customer growth for the next 20 years.

Capital Cost Calculations:

Meters - AMI Deployment Material Cost Calculation:								
Annual Number of Residential AMI Meters Deployed (#)	X	Cost per Residential AMI Meter ($)	X	Inflation	X	Contingency		
318,645		Confidential		2%		10%		
Annual Number of Small C&I AMI Meters Deployed (#)	X	Cost per Small C&I AMI Meter ($)						
29,797		Confidential						
Annual Number of Large C&I AMI Meters Deployed (#)	X	Cost per Large C&I AMI Meter ($)						
811		Confidential						

Meters - AMI Deployment Contractor Labor Cost Calculation:						
Annual Number of Residential AMI Meters Deployed (#)	X	Contractor Labor Cost per Residential AMI Meter Install ($)	Inflation (%)		Contingency (%)	
318,645		Confidential				
Annual Number of Small C&I AMI Meters Deployed (#)	X	Contractor Labor Cost per Small C&I AMI Meter Install ($)	X	X		
29,797		Confidential	2%		10%	
Annual Number of Large C&I AMI Meters Deployed (#)	X	Contractor Labor Cost per Large C&I AMI Meter Install ($)				
811		Confidential				

Meters - Labor Cost for Exchanges Needing Electrician Follow Up Calculation:									
Number of Meter Exchanges	X	Residential AMI Meters Deployed Needing Electrical Work (%)	X	Average Labor and Materials Cost	X	Inflation (%)	X	Contingency (%)	
1,356,026		0.2%		Confidential		2%		10%	

Meters - Internal Labor Cost for AMI Meters Returned and Require Utility Install Calculation:										
Annual Number of Residential AMI Meters Deployed (#)	X	Residential AMI Meters Deployed Returned to Utility (%)	X	Contractor Labor Cost per Residential AMI Meter Install ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
318,645		4.7%		$55.74		2%		10%		48%

Meters – Annual AMI Failure Replacement Material Cost Calculation:										
Number of Residential AMI Meters in System (#)	X	Cost per Residential AMI Meter ($)								
440,000-1,625,000		Confidential								
Number of Small C&I AMI Meters in System (#)	X	Cost per Small C&I AMI Meter ($)	X	Residential, Small C&I, and Large C&I Meter Replacement Rate (%/yr)	X	Inflation (%)	X	Contingency (%)		
42,000-156,000		Confidential		0.5%		2%		10%		
Number of Large C&I AMI Meters in System (#)	X	Cost per Large C&I AMI Meter ($)								
1,000-4,000		Confidential								

Meters – Annual AMI Failure Replacement Labor Cost Calculation:										
Number of Residential AMI Meters in System (#)	X	Cost per Residential AMI Meter Install/Exchange Internal Labor ($)								
440,000-1,625,000		$55.74								
Number of Small C&I AMI Meters in System (#)	X	Cost per Small C&I AMI Meter Install/Exchange Internal Labor ($)	X	Residential, Small C&I, and Large C&I Meter Replacement Rate (%/yr)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
42,000-156,000		$55.74		0.5%		2%		10%		94%
Number of Large C&I AMI Meters in System (#)	X	Cost per AMI Large C&I AMI Meter Install/Exchange Internal Labor ($)								
1,000-4,000		$55.74								

Meters List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Cost per Residential AMI Meter ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	The Company had this price secured with the vendor through 2027. Since price guarantees will expire prior to AMI deployment in this revised plan, AMI meter prices are expected to increase at a minimum of 2% inflation between 2026 and the start of AMI deployment.
Cost per Small C&I AMI Meter ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	
Cost per Large C&I AMI Meter ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	
Annual Number of Residential AMI Meters Deployed (#)	318,645	Company estimates a 3-year deployment and these values account for 1.5% annual meter growth between Year 1 and mid-Year 3 before AMI deployment starts	Meter growth may be higher or lower than 1.5% resulting in a more or less AMI meters required
Annual Number of Small C&I AMI Meters Deployed (#)	29,797		
Annual Number of Large C&I AMI Meters Deployed (#)	811		
Contractor Labor Cost per Residential AMI Meter Install ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	The Company had this price secured with the vendor through 2027. Since price guarantees have expired, AMI meter prices are expected to increase at a minimum of 2% inflation between 2026 and the start of AMI deployment.
Contractor Labor Cost per Small C&I AMI Meter Install ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	
Contractor Labor Cost per Large C&I AMI Meter Install ($)	Confidential	Current pricing with vendor for Massachusetts AMI Program and repurposed as estimates for Connecticut	
Cost per Residential AMI Meter	$55.74	Company labor data	

Meters List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Install/Exchange Internal Labor ($)			Internal labor rates may increase faster than 2% inflation
Cost per Small C&I AMI Meter Install/Exchange Internal Labor ($)	$55.74	Company labor data	
Cost per AMI Large C&I AMI Meter Install/Exchange Internal Labor ($)	$55.74	Company labor data	
Number of Meter Exchanges	1,356,026	Company Estimate	The number of meter exchanges can vary by year
% of Exchanges Needing Electrician Follow-Up	0.2%	Company Estimate	The amount of meters requiring repairs may be more or less than this estimate
Average Electrician Job Cost ($)	Confidential	Company cost data	The cost for repair may increase faster than 2% inflation
Residential AMI Meters Deployed Returned to Utility (%)	4.7%	Company Estimate based on MA deployment	The actual return to utility rate may be higher or lower than this estimate.
Residential, Small C&I, and Large C&I Meter AMI Replacement Rate (%/yr)	0.5%	Company estimate	The amount of meters requiring replacement may be more or less than this estimate
Number of Residential AMI Meters in System (#)	440,000-1,625,000	Begins in Year 2 of AMI deployment meter count is through Year 18 assuming 1.5% annual meter growth	1.5% meter growth may overstate or understate the number of total AMI meters in the system
Number of Small C&I AMI Meters in System (#)	42,000-156,000		
Number of Large C&I AMI Meters in System (#)	1,000-4,000		
Contingency (%)	10%	Company estimate	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years,

Meters List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
			inflation has risen higher than 2% annually

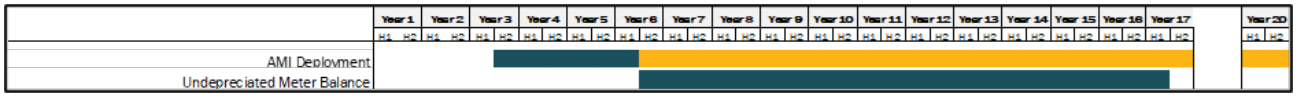
c. Annual Cost Calculation and Cost Granularity

	Capital						O&M	Total
	Internal Labor	External Labor	Materials	Corporate Overhead	Contingency	Total Capital	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**	**$0.00**
Year 3	$1.12	$8.38	$34.80	$0.54	$4.43	**$49.27**	**$0.00**	**$49.27**
Year 4	$2.50	$17.10	$70.18	$1.20	$8.98	**$99.96**	**$0.00**	**$99.96**
Year 5	$2.70	$17.45	$70.60	$1.30	$9.07	**$101.12**	**$0.00**	**$101.12**
Year 6	$1.65	$8.90	$36.00	$0.79	$4.65	**$52.00**	**$0.00**	**$52.00**
Year 7	$0.48	$0.00	$1.24	$0.23	$0.17	**$2.13**	**$0.00**	**$2.13**
Year 8	$0.50	$0.00	$1.29	$0.24	$0.18	**$2.20**	**$0.00**	**$2.20**
Year 9	$0.52	$0.00	$1.33	$0.25	$0.18	**$2.28**	**$0.00**	**$2.28**
Year 10	$0.53	$0.00	$1.38	$0.26	$0.19	**$2.36**	**$0.00**	**$2.36**
Year 11	$0.55	$0.00	$1.43	$0.27	$0.20	**$2.44**	**$0.00**	**$2.44**
Year 12	$0.57	$0.00	$1.48	$0.28	$0.21	**$2.53**	**$0.00**	**$2.53**
Year 13	$0.59	$0.00	$1.53	$0.29	$0.21	**$2.62**	**$0.00**	**$2.62**
Year 14	$0.61	$0.00	$1.58	$0.30	$0.22	**$2.71**	**$0.00**	**$2.71**
Year 15	$0.64	$0.00	$1.64	$0.31	$0.23	**$2.81**	**$0.00**	**$2.81**
Year 16	$0.66	$0.00	$1.70	$0.32	$0.24	**$2.91**	**$0.00**	**$2.91**
Year 17	$0.68	$0.00	$1.76	$0.33	$0.24	**$3.01**	**$0.00**	**$3.01**
Year 18	$0.71	$0.00	$1.82	$0.34	$0.25	**$3.12**	**$0.00**	**$3.12**
Year 19	$0.73	$0.00	$1.88	$0.35	$0.26	**$3.23**	**$0.00**	**$3.23**
Year 20	$0.76	$0.00	$1.95	$0.36	$0.27	**$3.34**	**$0.00**	**$3.34**
20-Year Total	**$16.50**	**$51.83**	**$233.59**	**$7.94**	**$30.19**	**$340.04**	**$0.00**	**$340.04**
20-Year NPV	**$9.26**	**$38.26**	**$165.10**	**$4.46**	**$21.26**	**$238.33**	**$0.00**	**$238.33**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

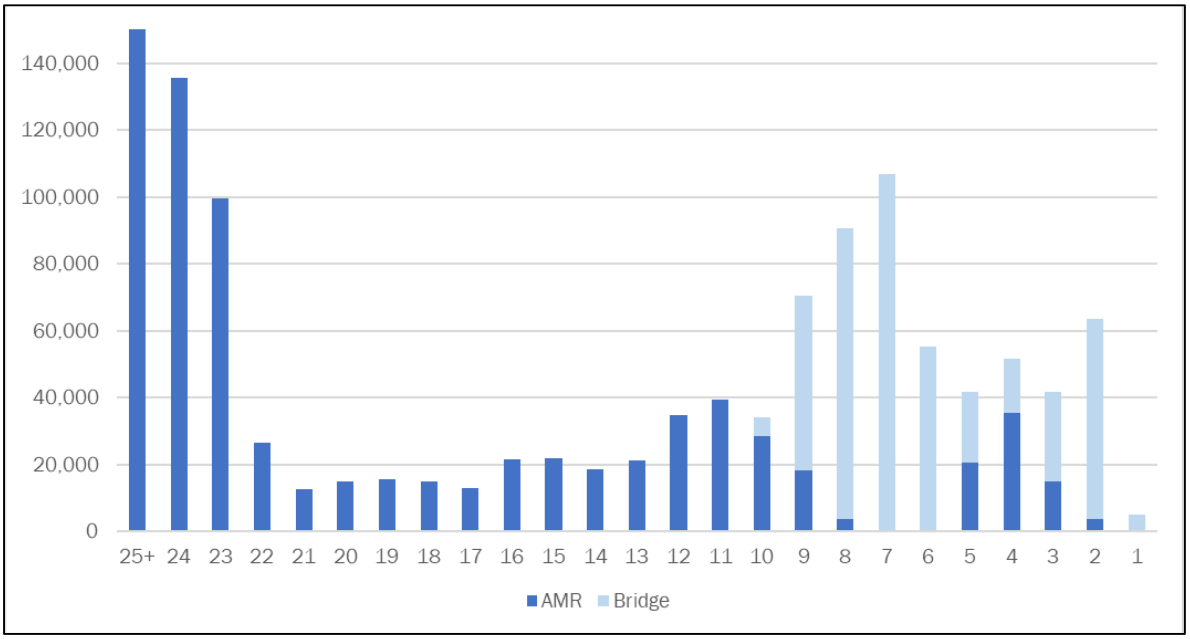
(ii) Undepreciated Meter Balance



a. Description

The majority of the existing Eversource AMR and bridge meter population is nearing the end of its useful life. The Company transitioned from manual meter reading to its current AMR drive-by system in the early 2000s, installing over 600,000 meters between 2000 and 2003. As a result, as shown in Figure 10, by 2029, approximately 600,000 meters, nearly 50% of the Company's meter population, will be over their estimated useful life of 20-years.

Figure 10 – Electric Meter Age Profile



The remaining AMR and bridge meters that have not reached the end of their useful life will also be replaced as part of the AMI implementation to ensure that the benefits of the AMI deployment are realized for the entire meter population of 1.4 million meters. As a result, the undepreciated meter costs for the AMR and bridge meters are considered additional costs from the business-as-usual case where meters are replaced at the end of their useful life.

Undepreciated meter balance does not materially support any benefits.

b. Cost Calculation Methodology

The Company's net asset value after accumulated depreciation of all meter assets at the end of 2025, represented as Year -1 in the figures below, is $179,884,927 and meter assets depreciate at 4.92% per year. By the time AMI meter deployment is proposed to begin, current meters will have a book value of $133.8 million and by the end of deployment will have a book value of $99.2 million. However, between now and AMI meter deployment proposed to begin in mid-Year 3 and end in mid-Year 6, new meter assets are installed annually due to meters reaching end of life or suffering damage.

On average over the past 10 years from 2016 to 2025, the Company installed $9.9 million in meter assets annually. It is assumed this amount of annual activity will continue until the first year of AMI meter deployment is proposed to begin in mid-Year 3. Each annual $9.9 million meter asset addition is depreciated at 4.92%. However, during deployment from mid-Year 3 to mid-Year 6, the amount of AMR meter activity will be reduced each year as AMI meters are deployed. 17% of all meters will be replaced with AMI in Year 3, 33% in Year 4 and in Year 5, and 17% in Year 6. The $179.9 million in net asset value of all meter assets on December 31, 2025 plus the annual additions from Year 0 to Year 6, each inflated at 2% and depreciated at 4.92%, will sum to a net asset value of meter assets of $136.7 million in Year 6 as shown in Figure 11. The $136.7 million is the amount of AMR meter balance that will be amortized over the next 10 years.

Figure 11 – Annual Net Asset Meter Values

AMR Meter Replacements												
Year	Average Annual AMR Activity	Remaining AMR Meters	Average Annual AMR Activity	Annual Depre-ciation	Net Asset Value							
					Year -1	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
									AMI Meter Deployment			
Year -1	N/A	100%	N/A	$11.5M	$179.9	$168.4	$156.8	$145.3	$133.8	$122.3	$110.7	$99.2
Year 0	$10.1	100%	$10.1	$0.5M		$10.1	$9.6	$9.1	$8.6	$8.1	$7.6	$7.1
Year 3	$10.3	100%	$10.3	$0.5M			$10.3	$9.8	$9.3	$8.8	$8.3	$7.7
Year 4	$10.5	100%	$10.5	$0.5M				$10.5	$10.0	$9.5	$8.9	$8.4
Year 5	$10.7	83%	$8.9	$0.4M					$8.9	$8.5	$8.0	$7.6
Year 6	$10.9	50%	$5.5	$0.3M						$5.5	$5.2	$4.9
Year 7	$11.1	17%	$1.9	$0.1M							$1.9	$1.8
Year 8	$11.3	0%	$0.0	$0.0M								$0.0
Total Net Asset Meter Value					$179.9	$178.4	$176.7	$174.6	**$170.5**	**$162.5**	**$150.6**	**$136.7**

Capital Cost Calculation:

Undepreciated Meter Balance - Annual Depreciation of Year -1 Meter Net Asset Value		
Net Asset Value of All Meter Assets on Year -1	-	Annual Depreciation Amount ($)
$179,884,927		$11,525,939

Undepreciated Meter Balance - Annual Depreciation of New Meter Assets New Meter Assets Added in				
Average Annual New Meter Assets Added from Year 0 to Year 4	X	Inflation (%)	X	Annual Depreciation Rate (%)
$9,878,575		2%		4.92%

Undepreciated Meter Balance - Annual Depreciation of New Meter Assets Added in 2029-2032 During AMI Deployment						
Average Annual New Meter Assets Added from Year 0 to 2030	X	Remaining AMR Meters From During AMI Deployment From Year 3 to Year 6 (%)	X	Inflation (%)	X	Annual Depreciation Rate (%)
$9,878,575		0% to 83%		2%		4.92%

Undepreciated Meter Balance - Annual Amortization of Undepreciated Meter Balance at Time of AMI Deployment Completion in 2032		
Total Amount of Undepreciated Meter Balance at End of AMI Deployment in Year 6 ($)	/	Amortization (years)
$136,749,712		10

Undepreciated Meter Balance List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Net Asset Value of All Meter Assets at the end of Year -1	$179,884,927	Company cost data	Estimate based on accumulated depreciation expense
Annual Depreciation Rate (%)	4.92%	Recent Rate Case per Docket #17-10-46	N/A
Annual Depreciation Amount ($)	$11,525,939	Gross asset value of all meter assets * annual depreciation rate	N/A
Average Annual New Meter Assets Added from 2024 to 2030	$9,878,575	2014-2025 10-year average of new meter assets added	The amount of new meter activity from Year 0 to Year 6 may vary depending on the amount of damaged meters and meters reaching end of life as well as other factors such as meter and prices increasing faster or slower than 2% inflation

Remaining AMR Meters From During AMI Deployment From Year 3 to Year 6 (%)	0% to 83%	Starting in mid-Year 3, 17% of all AMI meters are expected to be deployed (leaving 83% AMR meters in the system), 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections
Total Amount of Undepreciated Meter Balance at End of AMI Deployment in Year 6 ($)	$136,749,712	Company estimate based on calculation	The expected undepreciated meter balance at the first year of AMI deployment in mid-Year 3 is $176.7 million which is then allocated over 9 years. The amount of undepreciated meter balance depends on the amount of meters replaced between Year 0 -Year 3 when AMI deployment begins
Amortization (years)	10	Company estimate	
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

	Capital		O&M	Total
	Materials	Total Capital	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00
Year 2	$0.00	$0.00	$0.00	$0.00
Year 3	$0.00	$0.00	$0.00	$0.00
Year 4	$0.00	$0.00	$0.00	$0.00
Year 5	$0.00	$0.00	$0.00	$0.00
Year 6	$6.84	$6.84	$0.00	$6.84
Year 7	$13.67	$13.67	$0.00	$13.67
Year 8	$13.67	$13.67	$0.00	$13.67
Year 9	$13.67	$13.67	$0.00	$13.67
Year 10	$13.67	$13.67	$0.00	$13.67
Year 11	$13.67	$13.67	$0.00	$13.67
Year 12	$13.67	$13.67	$0.00	$13.67
Year 13	$13.67	$13.67	$0.00	$13.67
Year 14	$13.67	$13.67	$0.00	$13.67

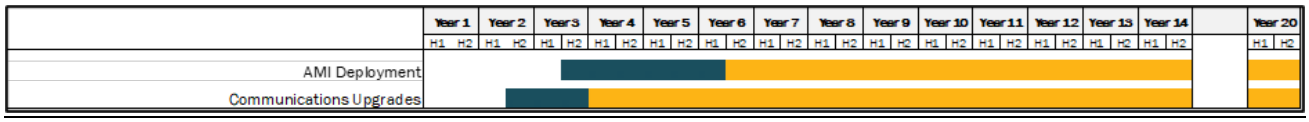
	Capital		O&M	Total
	Materials	Total Capital	O&M Total	
Year 15	$13.67	$13.67	$0.00	$13.67
Year 16	$6.84	$6.84	$0.00	$6.84
Year 17	$0.00	$0.00	$0.00	$0.00
Year 18	$0.00	$0.00	$0.00	$0.00
Year 19	$0.00	$0.00	$0.00	$0.00
Year 20	$0.00	$0.00	$0.00	$0.00
20-Year Total	$136.75	$136.75	$0.00	$136.75
20-Year NPV	$66.24	$66.24	$0.00	$66.24

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.2 COMMUNICATIONS

(i) Communications Upgrades



a. Description

The communications network is the backbone that enables the remote two-way communication between the meters and the back-office applications. For that purpose, in 2019 the Company performed a strategic assessment of available telecommunication for various use cases (e.g., AMI, distribution automation, mobile voice/data, etc.). The technologies assessed included public carrier cellular, private mesh, and point-to-multi-point wireless networks. Through this effort, the Company determined that a hybrid approach, utilizing a private wireless 'mesh' network coupled with public carrier cellular networks was the most effective technology suite that would satisfy the requirements of the AMI use cases. This flexible technology architecture can also be scaled to meet the Company's future gas and water AMI needs, when appropriate.

The Company assumes a mesh network solution leveraging the suite of systems currently under implementation in the Massachusetts AMI Program. This includes leveraging the latest advancement in 4G LTE and 5G network technology, which enables near real-time communications which were not economically feasible just five years ago.

The infrastructure for a wireless mesh network consists of meters with imbedded communications modules supporting mesh and/or cellular radios, wireless mesh collectors that collect meter data and transmit them to the back-office via fiber or wireless carrier, and repeaters for extending the mesh

network for hard-to-reach meters. In this architecture, each meter also acts as a repeater, enabling the 'mesh' that provides network resiliency through multiple communication paths.

The latest generation AMI mesh networks (1) enable powerful smart meters to run applications and securely share data among peer meters on the same transformer; (2) provide improved insights on the scope of outages; (3) rapidly sample and interrogate voltage quality; and (4) continuously provide awareness into the general health of the distribution system. The communication network that accompanies modern AMI deployments enables multiple new use cases and enhances existing use cases. In addition to the equipment, the costs associated with the mesh network include the head-end system necessary to securely encrypt/decrypt the meter data and make it ready for consumption by the other systems. Next generation AMI mesh networks also transmit non-mission critical sensor data, reducing the need to construct multiple communication networks.

As part of the communication infrastructure, the Company collaborated with its vendor partner to implement a novel multi-carrier subscriber identity module (SIM) technology that maximizes the strength and reliability of the AMI network. The multicarrier SIM solution mutually developed between the Company and the vendor offers a multi-carrier support system with dual-profile SIM cards capable of auto-switching between multiple cellular networks. This solution provides maximum carrier diversity and reliability for connectivity, while featuring a common vendor for AMI hardware, software, connectivity, and support. Key benefits include enhanced failover scenarios, priority access, and comprehensive device and connectivity management – all designed to support Eversource's deployment schedule efficiently.

To ensure communications accessibility across the full service territory, satellite and ethernet costs were included for locations where cellular service may be unreliable for AMI communications.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

As noted in Section D.1.i. - Meters, in 2023, the Company issued an RFP to the six leading AMI vendors in the United States. The costs detailed below apply actual contract data from the selected vendors supporting the on-going Massachusetts AMI Program. Conversely, the 2021 AMI Straw Proposal submitted to PURA was prepared utilizing pre-pandemic industry standards with information and costs based on the now out-of-date RFI responses. The contract with the selected vendors from the Massachusetts AMI Program informed the network costs for Connecticut by directly applying any per meter costs or proportioned lump sum costs by meter. The key cost components include cellular and mesh network materials and labor, IT expenses, headend, cellular connectivity fees, as well as upfront and ongoing technical labor, AMI operations labor, and network deployment professional services.

Communication upgrades are required prior to starting meter deployment to ensure that field communications are in place to bring meter data back to the operational centers. These costs start in mid-Year 2, one year prior to meter deployment, and implementation overlaps with meter deployment

in the second half of Year 3. This overlap does not affect meter benefit realization, as communications upgrades will be completed in areas where the first wave of meters is being deployed.

Capital Cost Calculations:

Communications Upgrades - Upfront Access Point Material Cost Calculations:						
Average Material Cost per Access Point ($)	X	Number of Access Points (#)	X	Inflation (%)	X	Contingency (%)
Confidential		2,050		2%		10%

Communications Upgrades – Upfront Access Point Installation External Labor Cost Calculations:						
Average Installation Cost per Access Point ($)	X	Number of Access Points (#)	X	Inflation (%)	X	Contingency (%)
Confidential		2,050		2%		10%

Communications Upgrades - Upfront Repeaters Materials Cost Calculations:						
Average Material Cost per Repeater ($)	X	Number of Repeaters (#)	X	Inflation (%)	X	Contingency (%)
Confidential		4,822		2%		10%

Communications Upgrades – Upfront Repeaters Installation External Labor Cost Calculations:						
Average Installation Cost per Repeater ($)	X	Number of Repeaters (#)	X	Inflation (%)	X	Contingency (%)
Confidential		4,822		2%		10%

Communications Upgrades - Upfront Socket AP Material Cost Calculations:						
Average Material Cost per Socket AP ($)	X	Number of Socket AP (#)	X	Inflation (%)	X	Contingency (%)
Confidential		2,900		2%		10%

Communications Upgrades - Network Deployment External Headend Professional Service Cost Calculations:				
Network Deployment Headend Professional Service ($)	X	Inflation (%)	X	Contingency (%)
Confidential		2%		10%

Communications Upgrades - Upfront Headend System Integration Testing Cost Calculations:				
Headend - System Integration and Acceptance Testing (Managed SaaS Fee) ($)	X	Inflation (%)	X	Contingency (%)
Confidential		2%		10%

Communications Upgrades - Upfront Headend Environment Refresh Cost Calculations:				
Headend Environment Refresh Fee ($)	X	Inflation (%)	X	Contingency (%)
Confidential		2%		10%

Communications Upgrades - Headend Business and IT Cost Calculations:						
Headend Business and IT Labor Cost ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$1,040,000		2%		10%		94%

Communications Upgrades - Upfront Mesh Network Material Capital Cost Calculations:									
Communication Tester Cost ($)	X	Communication Tester Quantity (#)	+	Meter Comms Module Tester Cost ($/unit)	X	Meter Comms Module Tester Quantity (#)	X	Inflation (%)	X	Contingency (%)
Confidential		5		Confidential		10		2%		10%

Communications Upgrades - Upfront IOT Test Environment Cost Calculations:				
IOT Test Environment ($)	X	Inflation (%)	X	Contingency (%)
Confidential		2%		10%

Communications Upgrades - Upfront Mesh Network Software Cost Calculations:						
Handheld Configurator & Tester Software ($/unit)	X	Handheld Configurator & Tester Software Quantity (#)	X	Inflation (%)	X	Contingency (%)
Confidential		130		2%		10%

Communications Upgrades - AMI Program Internal Labor Cost Calculations:											
AMI Ops Labor (Program) ($)	X	AMI Ops Labor (Program) (#)	+	AMI Technical Support Labor (Program) ($)	X	AMI Technical Support Labor (Program) (#)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)
$156,000		4		$208,000		2.5		2%		36%		10%

O&M Cost Calculations:

Communications Upgrades - Ongoing Headend Network SaaS Cost Calculations:									
Headend Annual Network SaaS Fee ($ per meter)	X	Total AMI Meters (#)	X	Meter Growth Rate (%)	X	Inflation (%)	X	Contingency (%)	
Confidential		1,356,026		1.5%		2%		10%	

Communications Upgrades - Cellular Connectivity Cost Calculations:											
Cellular Connectivity Fee ($ per meter per yr)	X	Total AMI Meters (#)	X	Percent of Meters Cellular Connected (%)	X	Meter Growth (%)	X	Inflation (%)	X	Contingency (%)	
Confidential		1,356,026		5%		1.5%		2%		10%	

Communications Upgrades - Ongoing Backhaul Cost Calculations:						
Total Annual Cellular Backhaul Costs ($ per AP)	X	Number of Access Points (#)	X	Inflation (%)	X	Contingency (%)
Confidential		2,050		2%		10%

Communications Upgrades - Ongoing Communication Tester Cost Calculations:						
Communication Tester Quantity (#)	X	Communications Tester - Software Maintenance and Support Cost ($)	X	Inflation (%)	X	Contingency (%)
5		Confidential		2%		10%

Communications Upgrades - Ongoing Regulator and Capacitor Cellular Cost Calculations:								
Number of Capacitors (#)	+	Number of Regulators (#)	X	VVO Cellular Fees (Ongoing Cost per Capacitor and Regulator) ($)	X	Inflation (%)	X	Contingency (%)
1,078		1,078		Confidential		2%		10%

Communications Upgrades – Access Point Replacement Internal Labor Cost Calculations:											
Access Point Replacements Installation Cost ($)	X	Number of Access Points (#)	X	Network Equipment Failure Rate (%)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
Confidential		2,050		0.25%-2%		2%		10%		94%

Communications Upgrades - Repeater Replacement Capital Cost Calculations:								
Number of Repeaters (#)	X	Network Equipment Failure Rate (%)	X	Repeater Replacements ($)	X	Inflation (%)	X	Contingency (%)
4,822		0.25% - 2%		Confidential		2%		10%

Communications Upgrades – Access Point Replacement Capital Cost Calculations:								
Number of Access Points (#)	X	Network Equipment Failure Rate (%)	X	Access Point Replacements ($)	X	Inflation (%)	X	Contingency (%)
2,050		0.25% - 2%		Confidential		2%		10%

Communications Upgrades - Battery and Other Equipment Replacement Capital Cost Calculations:										
Number of Access Points (#)	+	Number of Repeaters (#)	X	Network Equipment Failure Rate (%)	X	Battery Back-Up and Other Equipment ($)	X	Inflation (%)	X	Contingency (%)
2,050		4,822		2%		Confidential		2%		10%

Communications Upgrades - AMI Operations Internal Labor Cost Calculations:												
AMI Ops Labor (Operations) ($)	X	AMI Ops Labor (Operations) (#)	+	AMI Technical Support Labor (Operations) ($)	X	AMI Technical Support Labor (Operations) (#)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)
$156,000		2		$208,000		1		2%		36%		10%

Communications Upgrades – Ongoing Ethernet and Satellite Costs:										
Ongoing Monthly Ethernet Costs per AP	+	Ongoing Monthly Satellite Costs per AP	X	Month to Year Conversion	X	Number of APs Needing Satellite Connectivity	X	Inflation (%)	X	Contingency (%)
Confidential		Confidential		12		25		2%		10%

Communications Upgrades – Repeater Replacement Internal Labor Cost Calculations:											
Repeater Replacements Installation Cost ($)	X	Number of Repeater (#)	X	Network Equipment Failure Rate (%)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
Confidential		4,822		0.25%-2%		2%		10%		94%

Communications Upgrades – Satellite Upfront Cost Calculations:							
Upfront Satellite Costs per AP	X	Number of APs Needing Satellite Connectivity	X	Inflation (%)	X	Contingency (%)	
Confidential		25		2%		10%	

Communications Upgrades – Socket AP EOL Replacement Cost Calculations:								
Socket AP Unit Cost ($)	+	Socket AP Labor Cost ($)	X	Inflation (%)	^	Estimated Socket AP Lifespan (Years)	X	Contingency (%)
Confidential		Confidential		2		10		10%

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Average Material Cost per Access Point ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation
Average Installation Cost per Access Point ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	
Number of Access Points (#)	2,050	Company and vendor estimate	The number of access points required may be higher than this estimate
Average Material Cost per Socket AP ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation
Number of Socket AP (#)	2,900	Company and vendor estimate	The number of socket access points needed may be higher than this estimate
Average Material Cost per Repeater ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Average Installation Cost per Repeater ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	
Number of Repeaters (#)	4,822	Company and vendor estimate	The number of repeaters needed may be higher than this estimate
Network Equipment Failure Rate (%)	2%	Company estimate	The equipment failure rate might be higher than 2%
Access Point Replacement Cost ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	Costs may increase faster than 2% inflation
Access Point Replacements Installation Internal Labor Cost ($)	$885	Massachusetts contract with vendor and repurposed as estimates for CT	Costs may increase faster than 2% inflation
Repeater Replacement Cost ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	Costs may increase faster than 2% inflation
Relay Replacements Installation Internal Labor Cost ($)	$576	Massachusetts contract with vendor and repurposed as estimates for CT	Costs may increase faster than 2% inflation
Network Deployment Headend Professional Service ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation
AMI Ops Labor (Program) ($)	$156,000	Company cost estimate	Labor costs may increase a rate faster than 2% inflation
AMI Technical Support Labor (Program) ($)	$208,000	Company cost estimate	
AMI Ops Labor (Operations) ($)	$156,000	Company cost estimate	
AMI Technical Support Labor (Operations) ($)	$208,000	Company cost estimate	

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
AMI Ops Labor (Program) (#)	4	Company estimate	The amount of technical and AMI operations labor required in the future labor may be higher or lower
AMI Technical Support Labor (Program) (#)	2.5	Company estimate	
AMI Ops Labor (Operations) (#)	2	Company estimate	
AMI Technical Support Labor (Operations) (#)	1	Company estimate	
Headend - System Integration and Acceptance Testing (Managed SaaS Fee) ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation
Headend Environment Refresh Fee ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	
Headend Annual Network SaaS Fee ($ per meter)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	
IOT Test Environment ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	
Communication Tester Cost ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	
Communication Tester Quantity (#)	5	Company and vendor estimate	The number of communications testers may be higher than this estimate
Communications Tester - Software Maintenance and Support Cost ($)	Confidential	Company estimate	Costs may increase faster than 2% inflation
Headend Business and IT Labor Cost ($)	$1,040,000	Company estimate	The amount of internal labor to support headend could be more than this estimate

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Meter Comms Module Tester Cost ($/unit)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	Costs may increase faster than 2% inflation
Meter Comms Module Tester Quantity (#)	10	Company estimate	The amount of equipment may be more than this estimate
Handheld Configurator & Tester Software ($/unit)	Confidential	Massachusetts contract with vendor and repurposed as estimates for CT	Costs may increase faster than 2% inflation
Handheld Configurator & Tester Software Quantity (#)	130	Massachusetts contract with vendor and repurposed as estimates for CT	Costs may increase faster than 2% inflation
Battery Back-Up and Other Equipment (#)	57	Company estimate	The amount of equipment may be more than this estimate
Battery Back-Up and Other Equipment ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	If the communications network build-out begins after mid-Year 2, prices will increase and could be at a rate faster than 2% inflation
Cellular Connectivity Fee ($ per meter per yr)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	
Total Annual Cellular Backhaul Costs ($ per AP)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	
VVO Cellular Fees (Ongoing Cost per Capacitor and Regulator) ($)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	
Percent of Meters Cellular Connected (%)	5%	Company estimate	The percentage of cellular connected meter may be higher or lower than 5%.
Number of Capacitors (#)	1,078	Company estimate; Assumes 65% of all feeders will be enabled with VVO	The number of capacitors that must be enabled for VVO may be higher or lower than this estimate
Number of Regulators (#)	1,078	Company estimate; Assumes 65% of all	The number of regulators that must be enabled for VVO may be

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
		feeders will be enabled with VVO	higher or lower than this estimate
Upfront Satellite Cost per AP ($)	Confidential	Company estimate	Actual costs may be higher or lower
Ongoing Monthly Satellite Costs per AP ($)	Confidential	Company estimate	Actual costs may be higher or lower
Ongoing Monthly Ethernet Costs per AP ($)	Confidential	Company estimate	Actual costs may be higher or lower
Number of APs needing Satellite or Ethernet Connectivity (#)	25	Company estimate	Actual number of APs may be higher or lower
Socket AP Replacement Labor Cost	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	Costs may increase faster than 2% inflation
Expected Lifespan of Socket AP (Years)	10	Company Estimate	Actual EOL replacement rates may be higher or lower than estimates
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Total AMI Meters (#)	1,356,026	Company data	The number of meters may increase faster than 1.5% annual growth and could impact the number of repeaters, access points, and other equipment
Meter Growth (%)	1.5%	Company estimate based on historical and projections	Meters could grow greater or less than 1.5%

Communications Upgrades List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

c. Annual Cost Calculation and Cost Granularity

	Capital (1 of 2)					
	Internal Labor	External Labor	Materials	Hardware	Software	Software / Licensing Fees
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Year 2	$0.76	$12.18	$14.82	$0.20	$0.63	$0.00
Year 3	$1.55	$5.97	$29.64	$0.40	$1.26	$1.33
Year 4	$0.01	$2.00	$0.08	$0.00	$0.00	$1.33
Year 5	$0.01	$1.98	$0.08	$0.00	$0.00	$1.43
Year 6	$0.01	$1.03	$0.08	$0.00	$0.00	$1.54
Year 7	$0.11	$0.00	$0.66	$0.00	$0.00	$1.64
Year 8	$0.11	$0.00	$0.66	$0.00	$0.00	$1.76
Year 9	$0.11	$0.00	$0.66	$0.00	$0.00	$1.87
Year 10	$0.11	$0.00	$0.66	$0.00	$0.00	$2.26
Year 11	$0.11	$0.00	$0.66	$0.00	$0.00	$2.27
Year 12	$0.12	$0.00	$0.66	$0.00	$0.00	$2.29
Year 13	$0.12	$1.30	$3.30	$0.00	$0.00	$2.30
Year 14	$0.12	$2.59	$5.95	$0.00	$0.00	$2.32
Year 15	$0.12	$0.00	$0.66	$0.00	$0.00	$2.33
Year 16	$0.13	$0.00	$0.66	$0.00	$0.00	$2.35
Year 17	$0.13	$0.00	$0.66	$0.00	$0.00	$2.37
Year 18	$0.13	$0.00	$0.66	$0.00	$0.00	$2.38
Year 19	$0.13	$0.00	$0.66	$0.00	$0.00	$2.40
Year 20	$0.14	$0.00	$0.66	$0.00	$0.00	$2.42
20-Year Total	**$4.03**	**$27.05**	**$61.91**	**$0.61**	**$1.88**	**$36.59**
20-Year NPV	**$2.64**	**$20.68**	**$44.32**	**$0.51**	**$1.57**	**$16.69**

	Capital (2 of 2)			
	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.71	$2.86	$0.67	**$32.82**
Year 3	$1.45	$4.01	$1.83	**$47.44**
Year 4	$0.09	$0.34	$0.00	**$3.86**
Year 5	$0.09	$0.35	$0.00	**$3.95**
Year 6	$0.09	$0.27	$0.00	**$3.01**
Year 7	$0.72	$0.24	$0.00	**$3.38**
Year 8	$0.72	$0.25	$0.00	**$3.50**
Year 9	$0.73	$0.26	$0.00	**$3.64**
Year 10	$0.73	$0.30	$0.00	**$4.06**
Year 11	$0.73	$0.30	$0.00	**$4.08**
Year 12	$0.73	$0.31	$0.00	**$4.10**
Year 13	$0.73	$0.70	$0.00	**$8.46**

	Capital (2 of 2)			
	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 14	$0.74	$1.10	$0.00	**$12.81**
Year 15	$0.74	$0.31	$0.00	**$4.17**
Year 16	$0.74	$0.31	$0.00	**$4.19**
Year 17	$0.74	$0.32	$0.00	**$4.22**
Year 18	$0.75	$0.32	$0.00	**$4.24**
Year 19	$0.75	$0.32	$0.00	**$4.26**
Year 20	$0.75	$0.32	$0.00	**$4.29**
20-Year Total	**$12.72**	**$13.21**	**$2.50**	**$160.49**
20-Year NPV	**$6.27**	**$8.64**	**$2.08**	**$103.40**

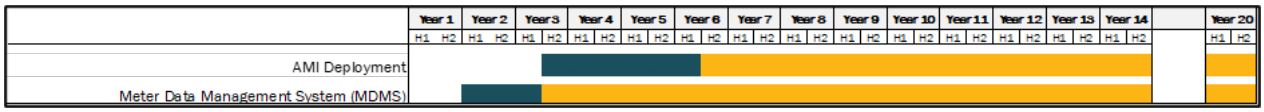
	O&M					Total
	Internal Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$32.82**
Year 3	$0.00	$1.01	$0.00	$0.10	**$1.11**	**$48.55**
Year 4	$0.56	$2.98	$0.53	$0.35	**$4.43**	**$8.29**
Year 5	$0.57	$4.92	$0.54	$0.55	**$6.58**	**$10.53**
Year 6	$0.59	$5.93	$0.55	$0.65	**$7.72**	**$10.73**
Year 7	$0.60	$6.02	$0.56	$0.66	**$7.84**	**$11.22**
Year 8	$0.61	$6.11	$0.57	$0.67	**$7.97**	**$11.47**
Year 9	$0.62	$6.21	$0.58	$0.68	**$8.09**	**$11.73**
Year 10	$0.63	$6.30	$0.59	$0.69	**$8.22**	**$12.28**
Year 11	$0.65	$6.39	$0.61	$0.70	**$8.35**	**$12.43**
Year 12	$0.66	$6.49	$0.62	$0.71	**$8.48**	**$12.59**
Year 13	$0.67	$6.59	$0.63	$0.73	**$8.62**	**$17.07**
Year 14	$0.69	$6.69	$0.64	$0.74	**$8.75**	**$21.56**
Year 15	$0.70	$6.79	$0.66	$0.75	**$8.89**	**$13.06**
Year 16	$0.71	$6.89	$0.67	$0.76	**$9.03**	**$13.23**
Year 17	$0.73	$6.99	$0.68	$0.77	**$9.18**	**$13.39**
Year 18	$0.74	$7.10	$0.70	$0.78	**$9.32**	**$13.56**
Year 19	$0.76	$7.20	$0.71	$0.80	**$9.47**	**$13.73**
Year 20	$0.77	$7.31	$0.72	$0.81	**$9.62**	**$13.91**
20-Year Total	**$11.26**	**$107.93**	**$10.57**	**$11.92**	**$141.68**	**$302.17**
20-Year NPV	**$5.12**	**$48.68**	**$4.80**	**$5.38**	**$63.98**	**$167.37**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.3 BACK-OFFICE SYSTEMS

(i) Meter Data Management System (MDMS)



a. Description

The MDMS is a key element for managing the large quantities of meter data generated by AMI meters. The MDMS collects and stores meter data from a head-end system and processes meter data into information that can be used by other utility systems such as the CIS. The core MDMS functionality includes validating, estimating, and editing ("VEE") meter reads before the reads are passed on to the CIS. The MDMS can also perform some basic analytics and will be able to provide reports around theft and tamper detection. Data points such as customer usage data are fed from the MDMS to other systems including the new CIS to enable TOU/TVR and the customer portal to provide usage insights and alerts to customers. To ensure the Company is fully realizing the benefits enabled by AMI investments, the selected MDMS will be fully capable of supporting the advanced functionalities enabled by the new generation of AMI meters.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The costs for the MDMS were calculated using actual upfront and ongoing costs to implement and maintain the new MDMS system for the Massachusetts AMI Program. The key cost components include application software, interfaces, procurement and contracting services, system implementation services, consulting services, internal labor, hardware, program management, data conversion, training, and ongoing service and maintenance fees. Additionally, exceptions will arise during AMI deployment as well as ongoing VEE of interval reads for TOU customers. Billing group overtime is required to handle the exceptions during deployment and additional Billing group labor is required for ongoing VEE for TOU/TVR meters.

Capital Cost Calculations:

MDMS - Internal Labor Calculation:								
MDM Internal Labor ($)	+	MDM Training ($)	X	Inflation (%)	X	Contingency (%)	X	IT Labor Overhead (%)
$2,700,000		$1,190,000		2%		20%		94%

MDMS - External Labor Calculation:						
MDM Professional Systems	+	MDM Contractor Labor ($)	X	Inflation (%)	X	Contingency (%)
$37,769,645		$1,485,102		2%		20%

MDMS – Upfront Software Costs Calculation:				
MDM Application Software ($)	X	Inflation (%)	X	Contingency (%)
$2,452,100		2%		20%

O&M Cost Calculations:

MDMS – Ongoing Annual Software and Storage Licensing Costs Calculation:						
MDM Annual Data Storage Fees ($)	+	MDM Annual Software Licensing Fees ($)	X	Inflation (%)	X	Contingency (%)
$2,734,000		$362,800		2%		20%

MDMS - Ongoing Labor Calculation:						
MDMS Annual MDMS Internal Labor ($/year)	X	Inflation (%)	X	Contingency (%)	X	IT Labor Overhead (%)
$340,000		2%		20%		94%

MDMS - Billing Annual Budget Increase During Deployment for Exceptions Calculation: *Will result in overtime for current staff*												
Average Annual Number of Residential, Small C&I, and Large C&I AMI Meters Deployed (#)	X	% of Deployed AMI Meters Resulting in an Exception	X	Average Handle Time per Exception (min.)	/	Minutes in Hour	/	Working Hours Per Year	X	Billing CSR Labor Rate ($)	X	Contingency (%)	X	Billing Labor Overhead (%)
339,007		3%		12		60		2,080		$78,000		20%		67%

MDMS – Annual MDMS Team Budget Increase During Deployment for Exceptions Calculation: *Will result in overtime for current staff*										
Average Annual Number of Residential, Small C&I, and Large C&I AMI Meters Deployed (#)	X	% of Deployed AMI Meters Resulting in an Exception	X	Average Handle Time per Exception (min.)	/ Minutes in Hour	/ Working Hours Per Year	X Billing MDM Team Labor Rate ($)	X Contingency (%)	X Billing Labor Overhead (%)
339,007		3%		15	60	2,080	$93,500	20%	94%

MDMS - Billing Annual Budget Increase Post-Deployment for VEE Exceptions From TOU Customers Calculation:									
Number of FTEs for TOU VEE Steady State after AMI Deployment (#)	X	Billing CSR Labor Rate ($)	X	Inflation (%)	X	Contingency (%)	X	Billing Labor Overhead (%)	
4		$78,000		2%		20%		67%	

Meter Data Management System (MDMS) List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
MDMS Professional Systems ($)	$37,769,645	Cost data from Massachusetts MDMS implementation and repurposed as estimates for Connecticut, including allocation amount for Massachusetts	Assumes 1.5 year implementation starting in Year 2, but if duration extends, costs could increase. Current pricing may increase faster than 2% inflation
MDMS Contactor Labor ($)	$1,485,102		
MDMS Training ($)	$1,190,000		
MDMS Software ($)	$2,452,100		
MDMS Internal Labor ($)	$2,700,000		
MDMS Annual MDMS Data Storage Fees ($/year)	$2,734,000		
MDMS Annual MDMS Internal Labor ($/year)	$340,000		

MDMS Annual Software License Maintenance ($/year)	$362,800		
Billing CSR Labor Rate ($)	$78,000	Company cost estimate	Labor costs may increase a rate faster than 2% inflation
Average Annual Number of Residential, Small C&I, and Large C&I AMI Meters Deployed (#)	339,007	Company estimate based on current meter population growing at 1.5% per year	1.5% growth rate may overstate or understate meter growth
Percentage of Deployed AMI Meters Resulting in an Exception and Handled by CSRs (%)	3%	Industry benchmark and Company estimate	The number of exceptions handled by the Billing team may be more than 2%, which could require additional FTEs
Billing Average Handle Time per Exception (minutes)	12	Company data	Average handle time per exception may increase, especially with adjusting to the new systems and processes
MDMS Labor Rates ($)	$93,500	Company cost estimate	Labor costs may increase a rate faster than 2% inflation
MDMS Average Exception Time (minutes)	15	Company data	Average handle time per exception may increase, especially with adjusting to the new systems and processes
Working Hours Per Year	2,080	40 hours per week * 52 weeks per year	
Number of FTEs for VEE Steady State after AMI Deployment (#)	4	Company cost estimate	The number of FTEs required may be greater or less than this estimate
Billing Labor Overhead (%)	67%	Company cost estimate	Actual future company overheads may be higher or lower than this value
IT Labor Overhead (%)	94%	Company cost estimate	Actual future company overheads may be higher or lower than this value

Contingency (%)	20%	Company cost estimate	Actual upfront and ongoing contingency may be higher or lower than 20%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

	Capital (1 of 2)			
	Internal Labor	External Labor	Software	Software Licensing/Fees
Year 1	$0.00	$0.00	$0.00	$0.00
Year 2	$0.94	$13.61	$0.82	$0.00
Year 3	$1.91	$27.77	$1.63	$0.14
Year 4	$0.00	$0.00	$0.00	$0.28
Year 5	$0.00	$0.00	$0.00	$0.28
Year 6	$0.00	$0.00	$0.00	$0.28
Year 7	$0.00	$0.00	$0.00	$0.31
Year 8	$0.00	$0.00	$0.00	$0.31
Year 9	$0.00	$0.00	$0.00	$0.31
Year 10	$0.00	$0.00	$0.00	$0.31
Year 11	$0.00	$0.00	$0.00	$0.31
Year 12	$0.00	$0.00	$0.00	$0.35
Year 13	$0.00	$0.00	$0.00	$0.35
Year 14	$0.00	$0.00	$0.00	$0.35
Year 15	$0.00	$0.00	$0.00	$0.35
Year 16	$0.00	$0.00	$0.00	$0.35
Year 17	$0.00	$0.00	$0.00	$0.38
Year 18	$0.00	$0.00	$0.00	$0.38
Year 19	$0.00	$0.00	$0.00	$0.38
Year 20	$0.00	$0.00	$0.00	$0.38
20-Year Total	**$2.85**	**$41.39**	**$2.45**	**$5.83**
20-Year NPV	**$2.38**	**$34.56**	**$2.05**	**$2.70**

	Capital (2 of 2)			
	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.88	$3.07	$0.61	**$19.93**
Year 3	$1.80	$6.29	$2.50	**$42.05**
Year 4	$0.00	$0.06	$0.00	**$0.34**
Year 5	$0.00	$0.06	$0.00	**$0.34**
Year 6	$0.00	$0.06	$0.00	**$0.34**
Year 7	$0.00	$0.06	$0.00	**$0.38**
Year 8	$0.00	$0.06	$0.00	**$0.38**
Year 9	$0.00	$0.06	$0.00	**$0.38**

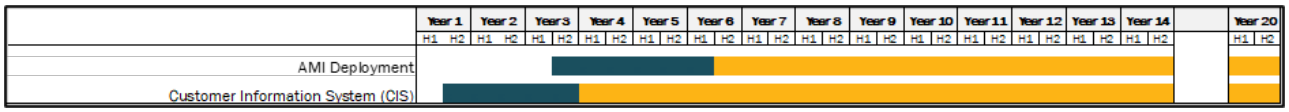
	Capital (2 of 2)			
	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 10	$0.00	$0.06	$0.00	**$0.38**
Year 11	$0.00	$0.06	$0.00	**$0.38**
Year 12	$0.00	$0.07	$0.00	**$0.42**
Year 13	$0.00	$0.07	$0.00	**$0.42**
Year 14	$0.00	$0.07	$0.00	**$0.42**
Year 15	$0.00	$0.07	$0.00	**$0.42**
Year 16	$0.00	$0.07	$0.00	**$0.42**
Year 17	$0.00	$0.08	$0.00	**$0.46**
Year 18	$0.00	$0.08	$0.00	**$0.46**
Year 19	$0.00	$0.08	$0.00	**$0.46**
Year 20	$0.00	$0.08	$0.00	**$0.46**
20-Year Total	**$2.68**	**$10.50**	**$3.11**	**$68.81**
20-Year NPV	**$2.23**	**$8.34**	**$2.58**	**$54.83**

	O&M					Total
	Internal Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.41	$0.00	$0.39	$0.08	**$0.88**	**$20.82**
Year 3	$1.16	$1.47	$1.09	$0.53	**$4.24**	**$46.29**
Year 4	$0.64	$2.94	$0.60	$0.71	**$4.89**	**$5.23**
Year 5	$0.99	$2.94	$0.93	$0.78	**$5.64**	**$5.98**
Year 6	$0.85	$2.94	$0.80	$0.76	**$5.35**	**$5.69**
Year 7	$0.75	$3.24	$0.70	$0.80	**$5.49**	**$5.87**
Year 8	$0.76	$3.24	$0.71	$0.80	**$5.51**	**$5.89**
Year 9	$0.76	$3.24	$0.72	$0.80	**$5.53**	**$5.90**
Year 10	$0.77	$3.24	$0.72	$0.80	**$5.54**	**$5.92**
Year 11	$0.78	$3.24	$0.73	$0.80	**$5.56**	**$5.93**
Year 12	$0.83	$3.58	$0.78	$0.88	**$6.07**	**$6.48**
Year 13	$0.83	$3.58	$0.78	$0.88	**$6.08**	**$6.50**
Year 14	$0.84	$3.58	$0.79	$0.88	**$6.10**	**$6.52**
Year 15	$0.85	$3.58	$0.80	$0.89	**$6.12**	**$6.53**
Year 16	$0.86	$3.58	$0.81	$0.89	**$6.14**	**$6.55**
Year 17	$0.91	$3.95	$0.86	$0.97	**$6.70**	**$7.16**
Year 18	$0.92	$3.95	$0.87	$0.98	**$6.72**	**$7.18**
Year 19	$0.93	$3.95	$0.87	$0.98	**$6.74**	**$7.20**
Year 20	$0.94	$3.95	$0.88	$0.98	**$6.76**	**$7.21**
20-Year Total	**$15.79**	**$60.21**	**$14.84**	**$15.20**	**$106.04**	**$174.84**
20-Year NPV	**$7.85**	**$27.86**	**$7.38**	**$7.14**	**$50.23**	**$105.06**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(ii) Customer Information System (CIS)



a. Description

A CIS is one of the most strategic and mission-critical information technology ("IT") systems within a utility. The CIS underpins a utility's ability to provide high-quality customer service as the platform for most interactions between a utility and its customers. The CIS also serves as a central repository of customer, billing, and account history data that is utilized by numerous other internal IT systems such as the load planning, outage management and general ledger systems.

A modern CIS is a prerequisite to support the full range of AMI benefits. The Company's current CIS is not capable of supporting AMI features at scale such as TOU/TVR rates, interval usage-based high bill alerts, and many of the other customer experience enhancements that will affect account actions and records. If the CIS is not replaced as part of the proposed AMI implementation, the Company would have to make substantial upgrades to the existing system to accommodate even basic AMI functionality and data requirements. Pursuing such upgrades would be short-sighted and inefficient as this path would be costly, time-consuming, and result in a short-lived solution with less functionality than a modern CIS. Transitioning to a modern CIS as part of the AMI implementation is the most cost-effective path, providing long-term standardization across the Company's jurisdictions, allowing customers to benefit from modern functionality and future enhancements, and incorporating advanced cyber security.

Capabilities within a CIS are typically organized around the major business processes it supports including:

- Billing – the ingestion of meter reads from a metering system and the calculation and generation of customers' bills based upon the stored tariffs in the CIS;
- Customer care – the handling of customer calls and inquiries (both live and automated) by providing information to the Company's agents and the customers directly including usage history, amounts owed, payments made, and available programs and services that may provide benefit to a customer or group of customers;
- Credit and collections – the calculation and tracking of past due amounts and payment arrangements including the interaction with third-party agencies that provide low-income assistance as well as parties which help collect overdue amounts;
- Start/stop service – the initiation of service for new customers with the utility and the suspension and/or termination of accounts no longer serviced by the utility.
- Field services – the coordination with downstream utility systems that help manage the field workers to initiate connect, disconnect, on-demand reads, RA investigations, and other services that involve visits to a customer's premise.

Primary users of the CIS include contact center agents who spend much of their day logged into the CIS and communicating directly with customers. Customer inquiries and commitments, along with agents' notes related to the call or chat, are recorded in the CIS. Meanwhile, more complex interactions that require additional investigation are handled by billing technicians who work directly with information stored within the CIS and other systems to help resolve customer inquiries. Additionally, numerous other departments and employees rely upon the CIS to perform their duties, including:

- Distribution engineers – utilize usage information in the CIS to plan system extensions and upgrades;
- Customer communications and program management – utilize usage and payment information in the CIS to research customer needs, preferences and behaviors, and design new services and programs for customers;
- Rates department – utilize usage information to perform rate planning and analysis;
- Field technicians – utilize account information to verify service addresses and schedule appointments.

The benefits of a modern CIS typically fall within three broad and overlapping categories: (1) risk mitigation; (2) enhanced customer capabilities; and (3) greater cost-effectiveness.

Risk mitigation

Most "legacy" CIS platforms (i.e., based on software engineered around year 2000, or earlier) were built using languages and technologies that are becoming obsolete, harder to sustain, and extend. While many legacy CIS systems have been optimized over time to produce accurate bills in a cost-efficient fashion, the ability to modify these systems to support new customer demands and programs is costly and carries significant technical risk. For example, modern CIS platforms support more flexible rate structures such as TOU/TVR and distributed generation natively through configuration. Modifying a legacy CIS to support TOU/TVR would require a substantial architectural overhaul, and in some cases may not be feasible. As the pace of change in customer expectations has increased, the cost and complexity of building and sustaining those capabilities within a legacy CIS has also increased.

Enhanced customer capabilities

Customers have come to expect convenience, speed, and personalization when interacting with their utility providers. Although utilities continue to handle a large volume of inbound calls, customers show increasing interest in conducting business via digital channels such as the utility website, chat and mobile applications. Modern CIS platforms enable this broader set of customer capabilities in a variety of ways including:

- Providing real-time access for a utility's website, interactive voice response ("IVR") system, and mobile apps to interact with the CIS, enhancing self-service capabilities

- Providing customers greater insight into their consumption patterns, projected bill amount, and tips for greater conservation through robust data models. These data models also benefit the Company through access to a richer set of customer data.
- Utilizing a more flexible architecture, including use of the cloud, which allows new capabilities to be deployed more rapidly and cost effectively.

Greater Cost-effectiveness

As legacy CIS platforms become antiquated and complex, costs generally increase due to three primary factors.

First, the complexity and use of outdated technology of the legacy CIS often means meeting changing customer and regulatory requirements is a time-consuming and expensive endeavor. Since legacy CISs are generally utility-specific, the cost for any enhancement must be borne by that utility. In contrast, modern CIS platforms, such as those marketed by Oracle and SAP, are deployed at hundreds of utilities globally and are designed in accordance with product roadmaps that seek to address the customer and regulatory demands and cybersecurity risks that its clients are facing. This translates to reduced customization requirements and associated enhancement costs for modern CIS.

The second primary factor is labor costs. Utilities running a legacy CIS experience a year-over-year loss of available people who are skilled in supporting a utility's legacy CIS. This not only presents operational risk, it also often translates into higher costs as utilities seek to supplant that loss of knowledge with outside expertise. By contrast, modern CIS platforms are implemented and supported by numerous organizations, large and small, creating a robust marketplace for skilled labor on these software platforms.

The third factor contributing to the greater cost-effectiveness of modern systems is their ability to automate activities handled manually or inefficiently by the legacy CIS. Many legacy CIS users are forced to build manual workarounds to address the inability of the system. Common examples include billing for complex rate structures, tracking net energy metering pricing plans, generating consolidated bills for multi-account customers, and providing call center agents and customers the ability to quickly compare utility rates. In contrast, modern CIS platforms support most utility requirements natively, reducing the need for manual support or integration with secondary systems. In addition, modern CIS platforms include robust workflow and reporting tools that drive greater efficiency and better decision making.

To fully enable the proposed features of the AMI deployment, the Company proposes to replace its existing, legacy CIS with a modern CIS that brings with it the benefits described above.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The costs for the CIS are estimated using indicative estimates based on the Company's CIS replacement and integration costs for the Massachusetts AMI Program and modeling for population

base in Connecticut. The costs include labor, hardware, software, procurement/contracting costs, integration of the CIS into existing systems, and the required data conversions. Also included are annual maintenance labor and license fees, along with annual increases in the billing budget. The costs for CIS detailed in the BCR Report are for electric customers only and adding gas customers would add incremental cost.

Meter-related billing cost estimates assume a temporary, contractor-based surge in billing resources during the AMI deployment, modeled from MA actuals with a 133% one-time increase applied to the $4.7M billing actuals over a 4-year surge window during and 1 year after AMI meter deployment. Costs transition to a 15% steady-state increase to the pre-AMI/post-OMNI billing budget using internal labor. For MDM/MV90, the model assumes a 50% one-time contractor resource surge starting at the beginning of CIS through a full year following OMNI deployment for MV90 meter accounts.

Implementing TOU/TVR rates is expected to drive a 100% increase in billing exceptions for TVR customers. Based on assumed customer participation levels, the billing impact is estimated as a 12% steady-state increase in effort following TVR implementation.

Capital Cost Calculations:

CIS – Internal Labor Cost Calculation:						
CIS Internal Labor ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$6,775,511		2%		20%		94%

CIS - External Labor Cost Calculation:								
CIS Solution Integration Services ($)	+	CIS Third Party Services & System Integration ($)	+	CIS Cybersecurity & Compliance ($)	+	CIS Other Costs ($)	X Inflation (%)	X Contingency (%)
$51,980,488		$40,628,428		$3,584,861		$7,169,723	2%	20%

CIS - Hardware Calculation:				
CIS Infrastructure and Platform ($)	X	Inflation (%)	X	Contingency (%)
$2,389,908		2%		20%

CIS - Software Calculation:						
CIS Upfront Software & Licensing ($)	+	CIS Data and Data Conversion ($)	X	Inflation (%)	X	Contingency (%)
$35,848,613		$8,962,153		2%		20%

O&M Cost Calculations

CIS - Ongoing Software Licensing / Fees Calculation:				
CIS Annual Licensing, Hosting, Support, and Admin Fees ($)	X	Inflation (%)	X	Contingency (%)
$9,375,968		2%		20%

CIS - One-Time Billing Budget Increase (External Labor) Post-CIS Completion Calculation:									
Billing Labor Budget (electric only) with Overheads ($)	X	Billing System Labor Budget Increase For One Year Post-CIS (%)	X	Post-OMNI Surge Staffing Duration (Years)	X	Inflation (%)	X	Contingency (%)	
$4,744,822		105%		1.5		2%		20%	

CIS - One-Time Billing Budget Increase (External Labor) Overtime Pay Post-CIS Completion Calculation:											
Average Hours per Week of Overtime (Hours)	X	Number of Employees Receiving Overtime	X	Overtime Rate / Hour ($)	X	Surge Staffing Duration (Months)	X	Inflation (%)	X	Contingency (%)	
4		50		$45		20		2%		20%	

CIS - Steady-State Billing Budget Increase (Internal Labor) Post-CIS Completion Calculation:						
Billing Labor Budget (CT Electric) with Overheads ($)	X	Billing Labor Budget Steady-State Increase (%)	X	Inflation (%)	X	Contingency (%)
$4,744,822		15%		2%		20%

Billing – One-Time Billing Budget Increase (External Labor) During AMI Meter Deployment Cost Calculation:									
Billing Labor Budget (CT Electric) ($)	X	AMI Meter Deployment Billing Labor Budget Increase During Meter Deployment (%)	X	AMI Meter Deployment Surge Staffing Duration (Years)	X	Inflation (%)	X	Contingency (%)	
$4,744,822		133%		4		2%		20%	

Billing - Steady State Billing Budget Increase (Internal Labor) Post-AMI Deployment Completion Cost Calculation:									
Billing Labor Budget (CT Electric) ($)	X	OMNI Billing Labor Budget Increase Steady State After the 1-Year (%)	X	AMI Meter Deployment Steady State Duration (Years)	X	Inflation (%)	X	Contingency (%)	X	Billing Labor Overhead (%)
$4,744,822		15%		14		2%		20%		67%

Billing – One-Time MDM/MV90 Resources Increase (Internal Labor) for Post-OMNI Surge Period Cost Calculation:								
MV90 Team Resource Costs (CT Electric)	X	MDM/MV90 Billing Labor Budget Increase (%)	X	Post-OMNI Surge Staffing Duration (Years)	X	Inflation (%)	X	Contingency (%)
$837,809		50%		1.5		2%		20%

Billing – One-Time MDM/MV90 Resources Increase (Internal Labor) for Post-AMI Deployment Surge Period Cost Calculation:									
MV90 Team Resource Costs (CT Electric)	X	MDM/MV90 Billing Labor Budget Increase (%)	X	Post-AMI Surge Staffing Duration (Years)	X	Inflation (%)	X	Contingency (%)
$837,809		50%		1.0		2%		20%

Billing - Billing Increase Steady State (Internal Labor) Post-TVR Deployment Cost Calculation:									
CT Electric Billing Labor Annual Budget ($)	X	TOU/TVR Billing Labor Budget Increase Steady State Post TVR Implementation (%)	X	Inflation (%)	X	Contingency (%)	X	Billing Labor Overhead (%)
$4,744,822		12%		2%		20%		67%

Customer Information System (CIS) List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
CIS Annual Licensing, Hosting, Support, and Admin Fees ($)	$9,375,968	Cost data from Massachusetts CIS implementation and repurposed as estimates for Connecticut, including allocation amount for Massachusetts	Assumes 2-year implementation beginning in mid-Year 1, but if duration extends, costs could increase. Current pricing may increase faster than 2% inflation
CIS Upfront Software & Licensing ($)	$35,848,613		
CIS Platform - Infrastructure ($)	$2,389,908		
CIS Services - Solution Integration Services ($)	$51,980,488		
CIS Internal Labor ($)	$6,775,511		
CIS Third Party Services ($)	$40,628,428		
CIS Data and Data Conversion ($)	$8,962,153		
CIS Other Costs (OCM & Training, Testing and Quality Assurance, Decommissioning) (%)	$7,169,723		
CIS Cybersecurity & Compliance ($)	$3,584,861		
Billing System Labor Budget Increase (electric only) For One Year Post-CIS External Surge Staffing) (%)	105%	Company cost data from Massachusetts CIS implementation	Cost only expected to occur for 14 months the year after CIS is completed. Assumes external contractors are utilized for 14 months after CIS is completed. The amount of contractor support could vary

Customer Information System (CIS) List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Billing Labor Budget (electric only) with Overheads ($)	$4,744,822	Company cost data	Inflation could increase faster or slower than 2% annually which will impact the Billing labor budget after CIS implementation is complete in mid-Year 3
OMNI Billing Labor Budget (electric-only) Steady-State Internal Labor Increase (%)	15%	Company cost data from Massachusetts CIS implementation	15% increase from pre-CIS Billing budget inflated to mid-Year 3 when CIS implementation is scheduled to complete. Increases annually at 2% inflation steady state. The amount of ongoing internal labor could be higher or lower than this assumption
AMI Meter Deployment Billing Labor Budget Increase During Meter Deployment (%)	133%	Company estimate	Assumes surge staffing period during AMI meter deployment and 1 year after deployment ends. Contractor labor will support surge staffing.
AMI Meter Deployment Surge Staffing Duration (Years)	4	Company estimate	Estimated based on current projected meter deployment timeline
AMI Meter Deployment Steady State Duration (Years)	14	Company estimate	Estimated based on current projected meter deployment timeline
MV90 Annual Team Resource Costs (CT Electric) ($)	$837,809	Company cost data	Team resource may increase faster than 2% inflation.
MDM/MV90 Billing Labor Budget Increase 1-Year Only Post-Implementation (%)	50%	Company estimate	Assumes one-time surge staffing post-OMNI period for 1.5 years after OMNI go-live. Contractor labor will support surge staffing.
MDM/MV90 post-OMNI Surge Duration (Years)	1.5	Company estimate	Estimated based on current projected OMNI deployment timeline. Assumes surge staffing for 1.5 years after OMNI go-live
MDM/MV90 Post-AMI Surge Duration (Years)	1.0	Company estimate	Estimated based on current projected AMI meter deployment. Assumes surge staffing for the last full year of AMI meter deployment
TOU/TVR Billing Labor Budget Increase Steady	12%	Company estimate	Costs are expected to incur steady state post-TVR implementation. Assumes

Customer Information System (CIS) List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
State Post TVR Implementation (%)			internal labor to support 100% increase in exceptions.
Billing Labor Overhead (%)	67%	Company estimate	Actual future company overheads may be higher or lower than this value
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 20%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

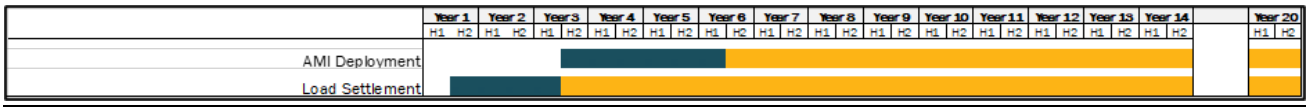
	Capital							
	Internal Labor	External Labor	Hardware	Software	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$3.25	$24.83	$2.29	$9.75	$1.62	$8.02	$1.55	**$51.32**
Year 2	$6.63	$50.66	$4.66	$19.89	$3.31	$16.37	$6.31	**$107.84**
Year 3	$3.38	$25.84	$2.38	$10.14	$1.69	$8.35	$1.61	**$53.39**
Year 4	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 7	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 8	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$13.27**	**$101.33**	**$9.33**	**$39.79**	**$6.63**	**$32.74**	**$9.46**	**$212.54**
20-Year NPV	**$11.59**	**$88.55**	**$8.15**	**$34.77**	**$5.79**	**$28.61**	**$8.26**	**$185.73**

	O&M						Total
	Internal Labor	External Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$5.56	$0.00	$1.11	**$6.67**	**$57.99**
Year 2	$0.00	$0.00	$8.27	$0.00	$1.65	**$9.93**	**$117.76**
Year 3	$0.00	$9.44	$7.91	$0.00	$3.47	**$20.81**	**$74.20**
Year 4	$0.00	$12.42	$7.79	$0.00	$4.04	**$24.26**	**$24.26**
Year 5	$0.79	$6.97	$8.23	$0.53	$3.20	**$19.70**	**$19.70**
Year 6	$0.80	$7.58	$8.66	$0.54	$3.41	**$20.99**	**$20.99**
Year 7	$1.76	$0.00	$8.83	$0.55	$2.12	**$13.26**	**$13.26**
Year 8	$1.79	$0.00	$9.01	$0.56	$2.16	**$13.52**	**$13.52**
Year 9	$1.83	$0.00	$9.19	$0.57	$2.20	**$13.79**	**$13.79**
Year 10	$2.56	$0.00	$9.37	$0.58	$2.39	**$14.90**	**$14.90**
Year 11	$2.61	$0.00	$9.56	$0.59	$2.43	**$15.20**	**$15.20**
Year 12	$2.66	$0.00	$9.75	$0.60	$2.48	**$15.50**	**$15.50**
Year 13	$2.72	$0.00	$9.95	$0.62	$2.53	**$15.81**	**$15.81**
Year 14	$2.77	$0.00	$10.15	$0.63	$2.58	**$16.13**	**$16.13**
Year 15	$2.83	$0.00	$10.35	$0.64	$2.64	**$16.45**	**$16.45**
Year 16	$2.88	$0.00	$10.56	$0.65	$2.69	**$16.78**	**$16.78**
Year 17	$2.94	$0.00	$10.77	$0.67	$2.74	**$17.12**	**$17.12**
Year 18	$3.00	$0.00	$10.98	$0.68	$2.80	**$17.46**	**$17.46**
Year 19	$3.06	$0.00	$11.20	$0.69	$2.85	**$17.81**	**$17.81**
Year 20	$3.12	$0.00	$11.43	$0.71	$2.91	**$18.16**	**$18.16**
20-Year Total	**$38.11**	**$36.40**	**$187.52**	**$9.81**	**$52.41**	**$324.25**	$536.79
20-Year NPV	**$15.62**	**$27.20**	**$93.94**	**$4.30**	**$27.35**	**$168.40**	$354.13

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(iii) Load Settlement



a. Description

Load Settlement refers to the process by which electric energy consumption is measured, reconciled, and allocated for purposes of wholesale market settlement and cost recovery. Within ISO New England (ISO-NE), settlement is performed on an hour basis and requires accurate attribution of load to applicable settlement intervals. Under the current metering framework, a significant portion of customer usage is represented using load profiles, which estimate hourly consumption based on class

averages rather than hourly measured data. As a result, settlement outcomes may differ from actual customer usage patterns.

AMI can provide the data for individual customer interval-based load settlement, where customer consumption is measured and recorded at hourly (or sub-hourly) intervals. This allows the Company to align retail load with ISO-NE settlement requirements using actual metered data rather than statistical estimates. Implementation of AMI facilitates a transition from profile-based settlement to measurement-based settlement, consistent with ISO-NE market constructs. This transition is relevant for several reasons:

- Interval data enables more precise assignment of energy and capacity costs to the customers who drive those costs, supporting principles of equity and reducing cross-subsidization among customer classes.
- AMI provides the data granularity necessary to reflect individual hourly usage for specific customers when reporting load information to ISO-NE for settlement purposes
- TVR, demand response programs, and distributed energy resource (DER) compensation mechanisms may benefit from interval usage data for both billing and settlement.
- Moving away from load profiles improves transparency in how costs are calculated and allocated.

The Company's current load settlement system cannot process the volume of data required for interval-based load settlement, therefore, a modern load settlement system is needed.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The costs for the Load Settlement system integrations are estimated using indicative estimates based on similar estimates performed for the Company's Massachusetts AMI program. The costs include labor, hardware, software, procurement/contracting costs, integration of the new system into existing systems, and the required data conversions. Also included are annual maintenance labor and license fees, along with annual increases in the billing budget. The costs for Load Settlement are for electric customers only and adding gas customers would add incremental cost.

Capital Cost Calculations (External Only):

Load Settlement - Pre-Project Activities Cost Calculation:								
Pre-Project Activities	X	Pre-Project Activities Duration (Months)	/	Months per Year	X	Inflation (%)	X	Contingency (%)
$463,658		6.0		12.0		2%		20%

Load Settlement – Capital Project Cost Calculation:								
Deployment Activities	X	Implementation Duration (Months)	/	Months per Year	X	Inflation (%)	X	Contingency (%)
$21,495,894		24.0		12.0		2%		20%

Capital and O&M Cost Calculations (Internal Only):

Load Settlement - Deployment Activities Cost Calculation:				
Annual O&M Costs	X	Inflation (%)	X	Contingency (%)
$1,500,000		2%		20%

Load Settlement List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Deployment Activities	$21,495,894	Company cost data	Assumes 3-year implementation beginning in mid-Year 1, but if duration extends, costs could increase. Current pricing may increase faster than 2% inflation. Implementation durations were estimated based on ranges provided by the Company. Actual implementation durations may be greater than estimates. Assumes that Massachusetts load settlement will be in place prior to implementation. If Massachusetts load settlement is not in place prior to implementation, costs can increase materially. Costs include an allocation amount for Massachusetts.
Pre-Project Activities	$463,658	Company cost data	
Pre-Project Activities Duration (Months)	6.0	Company estimate	
Implementation Duration (Months)	24.0	Company estimate	
Annual O&M Costs	$1,500,000	Company cost data	
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 25%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

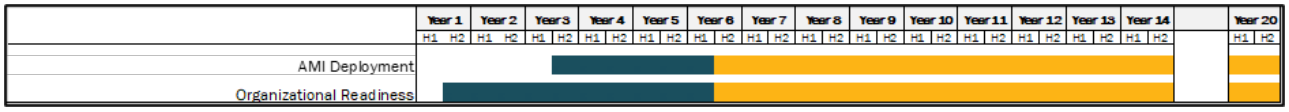
	Capital				O&M			Total
	External Labor	Contingency	AFUDC	Total Capital	Software Licensing / Fees	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$4.96	$0.99	$0.00	**$5.95**	$0.00	$0.00	**$0.00**	**$5.95**
Year 3	$9.12	$1.82	$0.00	**$10.95**	$0.00	$0.00	**$0.00**	**$10.95**
Year 4	$9.31	$1.86	$0.69	**$11.17**	$0.00	$0.00	**$0.00**	**$11.17**
Year 5	$0.00	$0.00	$0.00	**$0.00**	$1.66	$0.33	**$1.99**	**$1.99**
Year 6	$0.00	$0.00	$0.00	**$0.00**	$1.69	$0.34	**$2.03**	**$2.03**
Year 7	$0.00	$0.00	$0.00	**$0.00**	$1.72	$0.34	**$2.07**	**$2.07**
Year 8	$0.00	$0.00	$0.00	**$0.00**	$1.76	$0.35	**$2.11**	**$2.11**
Year 9	$0.00	$0.00	$0.00	**$0.00**	$1.79	$0.36	**$2.15**	**$2.15**
Year 10	$0.00	$0.00	$0.00	**$0.00**	$1.83	$0.37	**$2.19**	**$2.19**
Year 11	$0.00	$0.00	$0.00	**$0.00**	$1.87	$0.37	**$2.24**	**$2.24**
Year 12	$0.00	$0.00	$0.00	**$0.00**	$1.90	$0.38	**$2.28**	**$2.28**
Year 13	$0.00	$0.00	$0.00	**$0.00**	$1.94	$0.39	**$2.33**	**$2.33**
Year 14	$0.00	$0.00	$0.00	**$0.00**	$1.98	$0.40	**$2.38**	**$2.38**
Year 15	$0.00	$0.00	$0.00	**$0.00**	$2.02	$0.40	**$2.42**	**$2.42**
Year 16	$0.00	$0.00	$0.00	**$0.00**	$2.06	$0.41	**$2.47**	**$2.47**
Year 17	$0.00	$0.00	$0.00	**$0.00**	$2.10	$0.42	**$2.52**	**$2.52**
Year 18	$0.00	$0.00	$0.00	**$0.00**	$2.14	$0.43	**$2.57**	**$2.57**
Year 19	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.44	**$0.44**	**$0.44**
Year 20	$0.00	$0.00	$0.00	**$0.00**	$2.23	$0.45	**$2.67**	**$2.67**
20-Year Total	**$23.39**	**$4.68**	**$0.69**	**$28.76**	**$30.87**	**$6.17**	**$37.04**	**$65.80**
20-Year NPV	**$18.88**	**$3.78**	**$0.53**	**$23.18**	**$13.52**	**$2.70**	**$16.22**	**$39.40**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.4 LABOR AND STANDARD OPERATING PLAN

(i) Organizational Readiness



a. Description

Organizational Readiness includes labor resources dedicated to a program management office ("PMO") and a change management office ("CMO"). The PMO is responsible for ensuring that the project stays on time, remains on budget, and manages scope appropriately. Programmatic reporting, vendor management, business process management, quality control, risk management, procurement oversight, and resource allocation will also be performed by the PMO. The CMO will be responsible for ensuring communications to internal stakeholders are relevant and timely, sponsorship is active and visible, coaching needs are adequately met, resistance to activities and tasks is addressed, and all training is developed and executed in a timely manner. The PMO and CMO will be staffed by a mix of internal and external resources. This blended team approach combines internal stakeholders' knowledge of Company operations and processes with industry best practices and benchmarking data from external resources to result in superior outcomes.

Additionally, system integration required to ensure an end-to-end solution across the new systems and data and existing Company systems and processes. Each new vendor, such as those selected for the HES, CIS, and MDMS are responsible for integrations and data flows into and out of its own system but the system integrator is responsible for driving a holistic solution. Additionally, the system integrator is responsible for managing the design, build, and testing across all vendors as part of the overall solution delivery. The system integrator team is primarily driven by external labor resources.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The estimate of PMO, CMO, and system integrator costs is based on an estimate of the full time equivalent ("FTE") requirements for each resource type by year and an estimated labor rate. These costs accrue over the five-and-a-half-year (5.5) project term and reflect an assumption of labor rate inflation. Estimates for the type and extent of FTE requirements were supported by industry benchmarks and the Company's own experience implementing AMI in Massachusetts.

Capital Cost Calculations (External Only):

Organizational Readiness - External Cost Benefit Analysis Support Costs Calculation:		
Past CT Benefit-Cost Analysis External Costs ($)	X	Inflation (%)
$1,352,000		2%

Organizational Readiness - External PMO Support Costs Calculation:						
External PMO Cost per Year ($)	X	Years	X	Inflation (%)	X	Contingency (%)
$3,034,000		5.5		2%		10%

Organizational Readiness - External CMO Support Costs Calculation:						
External CMO Cost per Year ($)	X	Years	X	Inflation (%)	X	Contingency (%)
$2,530,000		3.5		2%		10%

Organizational Readiness - External SI Support Costs Calculation:							
External SI Cost per Year ($)	X	Years	X	Inflation (%)	X	Contingency (%)	
$9,100,000		3.5		2%		10%	

Organizational Readiness - Ongoing External Support Costs Calculation:				
Ongoing Consulting Support ($)	X	Years	X	Inflation (%)
$104,000		14		2%

Capital Cost Calculations (Internal Only):

Organizational Readiness - Internal PMO Capital Costs Calculation:								
Internal PMO Cost per Year (Capital) ($)	X	Years	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$2,576,364		5.5		2%		10%		94%

O&M Cost Calculations (Internal Only):

Organizational Readiness - Internal PMO O&M Costs Calculation:								
Internal PMO Cost per Year (O&M) ($)	X	Years	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$350,909		5.5		2%		10%		94%

Organizational Readiness List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
External PMO Cost per Year ($)	$3,034,000	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut	Assumes a 5.5 year implementation beginning in Year 1 and ending late Year 6, but if duration extends, costs could increase. Current pricing estimate may increase faster than 2% inflation
External PMO Services Duration (years)	5.5		
External CMO Cost per Year ($)	$2,530,000		Assumes a 3.5 implementation services beginning in mid-Year 1 and ending late Year 4, but if duration extends, costs could increase. Current pricing estimate may increase faster than 2% inflation
External CMO Services Duration (years)	3.5		
External SI Cost per Year ($)	$9,100,000	Cost data from Massachusetts AMI	Assumes a 3.5 implementation services beginning in mid-Year

Organizational Readiness List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
SI Services Duration (years)	3.5	Program and repurposed as estimates for Connecticut	1 and ending late Year 4, but if duration extends, costs could increase. Current pricing estimate may increase faster than 2% inflation
Past CT Benefit-Cost Analysis External Costs ($)	$1,352,000	Past costs for past AMI BCA consulting services, no calculation needed. Assume cost occurs in 2026	
Ongoing Consulting Support ($)	$104,000	Company estimate, no calculation needed	Estimate may overstate or understand the amount of ongoing consulting services.
Ongoing Consulting Support Duration (years)	14	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut	Current Massachusetts AMI Program data may overstate or understate FTEs for Connecticut
Internal PMO Cost per Year (Capital) with Overheads ($)	$2,576,364		
Internal PMO Cost per Year (O&M) with Overheads ($)	$350,909		
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value

c. Annual Cost Calculation and Cost Granularity

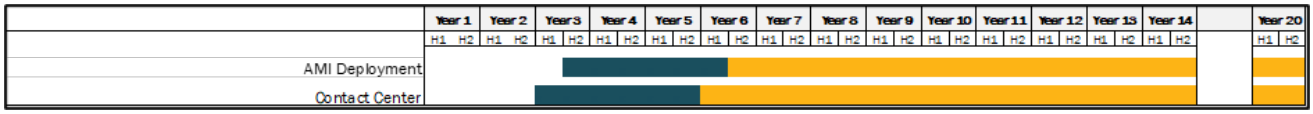
	Capital					O&M				Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	Total Capital	Internal Labor	Corporate Overhead	Contingency	O&M Total	
Year 1	$1.31	$8.83	$1.24	$0.88	**$12.26**	$0.18	$0.17	$0.02	**$0.37**	**$12.63**
Year 2	$2.68	$15.26	$2.52	$1.53	**$21.98**	$0.37	$0.34	$0.04	**$0.74**	**$22.73**
Year 3	$2.73	$15.56	$2.57	$1.56	**$22.42**	$0.37	$0.35	$0.04	**$0.76**	**$23.18**
Year 4	$2.79	$15.87	$2.62	$1.59	**$22.87**	$0.38	$0.36	$0.04	**$0.77**	**$23.65**
Year 5	$2.84	$3.35	$2.67	$0.33	**$9.20**	$0.39	$0.36	$0.04	**$0.79**	**$9.99**
Year 6	$2.90	$3.42	$2.73	$0.34	**$9.39**	$0.40	$0.37	$0.04	**$0.81**	**$10.19**
Year 7	$0.00	$0.12	$0.00	$0.01	**$0.13**	$0.00	$0.00	$0.00	**$0.00**	**$0.13**
Year 8	$0.00	$0.12	$0.00	$0.01	**$0.13**	$0.00	$0.00	$0.00	**$0.00**	**$0.13**
Year 9	$0.00	$0.12	$0.00	$0.01	**$0.14**	$0.00	$0.00	$0.00	**$0.00**	**$0.14**

	Capital					O&M				Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	Total Capital	Internal Labor	Corporate Overhead	Contingency	O&M Total	
Year 10	$0.00	$0.13	$0.00	$0.01	**$0.14**	$0.00	$0.00	$0.00	**$0.00**	**$0.14**
Year 11	$0.00	$0.13	$0.00	$0.01	**$0.14**	$0.00	$0.00	$0.00	**$0.00**	**$0.14**
Year 12	$0.00	$0.13	$0.00	$0.01	**$0.15**	$0.00	$0.00	$0.00	**$0.00**	**$0.15**
Year 13	$0.00	$0.13	$0.00	$0.01	**$0.15**	$0.00	$0.00	$0.00	**$0.00**	**$0.15**
Year 14	$0.00	$0.14	$0.00	$0.01	**$0.15**	$0.00	$0.00	$0.00	**$0.00**	**$0.15**
Year 15	$0.00	$0.14	$0.00	$0.01	**$0.15**	$0.00	$0.00	$0.00	**$0.00**	**$0.15**
Year 16	$0.00	$0.14	$0.00	$0.01	**$0.16**	$0.00	$0.00	$0.00	**$0.00**	**$0.16**
Year 17	$0.00	$0.15	$0.00	$0.01	**$0.16**	$0.00	$0.00	$0.00	**$0.00**	**$0.16**
Year 18	$0.00	$0.15	$0.00	$0.01	**$0.16**	$0.00	$0.00	$0.00	**$0.00**	**$0.16**
Year 19	$0.00	$0.15	$0.00	$0.02	**$0.17**	$0.00	$0.00	$0.00	**$0.00**	**$0.17**
Year 20	$0.00	$0.15	$0.00	$0.02	**$0.17**	$0.00	$0.00	$0.00	**$0.00**	**$0.17**
20-Year Total	**$15.26**	**$64.20**	**$14.35**	**$6.42**	**$100.23**	**$2.08**	**$1.95**	**$0.21**	**$4.24**	**$104.47**
20-Year NPV	**$11.89**	**$51.83**	**$11.18**	**$5.18**	**$80.08**	**$1.62**	**$1.52**	**$0.16**	**$3.30**	**$83.39**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(ii) Contact Center



a. Description

The costs associated with the contact center include the Company employees who are tasked with performing vital customer service activities with residential and commercial customers. This includes responding to credit-related inquiries, taking outage-related calls, and discussing billing questions, as well as the telephony system (hardware and software) utilized by these employees while performing their customer-facing duties. Our contact centers take calls from three states and resources are shared for increased efficiency. The contact center responds to ~1.5 million non-credit calls in Connecticut, on average, each year. ~160 customer service representatives ("CSR") handle credit calls for both Connecticut Electric and Yankee Gas and the electric share is approximately 90% of the total workload.

The Company anticipates a stabilization period for the new CIS that will impact the call handling efficiency for a time as the CSRs become familiar with the new systems and their functionality as it relates to responding to customer inquiries. The Company has forecast a reduction in CSR requirements over time as the new system is stabilized and customers become familiar with what is available, as well as other system improvements from the new technology.

There will be a need to add employees to handle an increase in customer calls related to meter change inquiries from customers during AMI deployment. In addition, the Company anticipates an initial, significant increase in average handle time ("AHT") associated with the new CIS, which will increase the number of resources required to respond to customer inquiries.

The combined CIS and AMI implementations will generate a significant amount of new information available to customers related to their energy use, bills and new rates that may be available. The Company thus expects a large increase in customer inquiries related to these new customer benefits.

In relation to the credit call center, the Company expects call volume to increase with the introduction of remote connect/disconnect ("RCD") technology, as RCD may enable a higher volume of delinquency-related disconnect activity. The Company's call volume and bad debt assumptions reflect current Connecticut policies and regulations; if those policies or enforcement practices change, the expected volumes (and related impacts) may change as well. Even under existing CT policies, because non-hardship customers represent a larger portion of the customer base than hardship customers, the Company anticipates an increase in delinquency disconnects—subject to delinquency policies—which could drive an increase in disconnect notices and the number of disconnects executed using AMI technology. See Section B.7.i. – Reduced Bad Debt for additional information.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

To determine the increase in the contact center costs related to AMI, the Company included specific costs of both new non-credit and credit surge staffing and ongoing resources based on the expected new call volumes and AHT.

For the residential and commercial call center to respond to non-credit call volumes, under the proposed timeline, the Company projects to add 90 FTEs one-time surge staffing to handle AHT increases related to the CIS implementation in following CIS go-live, which would drop down to 65 FTEs in two years following CIS go-live. A portion of these resources would support TOU/TVR program impact during those years as well. Three years after CIS implementation, no ongoing incremental resources as the number of CSRs would reduce back to pre-AMI levels.

For the call center to respond to credit call volumes, under the proposed timeline, in Year 3 the Company projects to add 80 one-time surge staffing contractor FTEs to handle AHT increases related to the CIS implementation. Starting after CIS implementation completes, the Company adds 60 FTE associated with sustained AHT increase and increased SONPs. Once real-time payments are implemented starting in Year 5, the steady state credit resources needed will decrease to 57 FTEs.

For the telephony costs, the Company increased the current budget by $50,000 annually starting the year after CIS go-live to account for the need to upgrade the system.

Capital Cost Calculations:

Contact Center - Upfront IVR Optimization Cost Calculation:						
One-Time IVR Optimization ($)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)
$300,000		2%		94%		10%

O&M Cost Calculations:

Contact Center - Ongoing Non-Credit Labor Cost Calculation:														
	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9+		Salary per FTE		Inflation (%)	X	Labor OH (%)	X	Contingency (%)
CIS Launch	90	-	-	-	-	-	-	X	$60,500	X		X		X	
AHT, TVR, TOU Impact	-	90	65	-	-	-	-	X	$60,500		2%		94%		10%

Contact Center - Ongoing Credit Labor Cost Calculation:													
	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9+		Salary per FTE	X	Inflation (%)	X	Contingency (%)
CIS Launch	80				-	-	-	X					
									$73,382		2%		10%
Steady State	-	60	57	57	57	57	57						

Contact Center - Ongoing Incremental Telephony Budget Calculation:				
Incremental Telephony Budget Increase ($)	X	Inflation (%)	X	Contingency (%)
$50,000		2%		10%

Contact Center List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Call Center Non-Credit - New CIS Completed FTE (#)	90	Company estimates 30% increase in call volume and 44% AHT increase	The increase in AHT and number of non-credit calls related to CIS and AMI deployment may be higher or lower depending on a number of factors which could require more or less call center FTEs

Contact Center List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Cost per Non-Credit FTE ($)	$60,500	Company data	Labor costs may increase a rate faster than 2% inflation
Call Center Credit – New CIS Completed FTE (#)	80	Company estimate	The increase in AHT related to CIS may be higher or lower depending on a number of factors which could require more or less call center FTEs
Call Center Credit FTE - Steady State (#)	57 to 60	Company estimate	60 FTE sustained incremental annual calls associated with increased SONPs, which is expected to reduce to 57 FTEs after the implementation of real-time payments. The number of SONPs and associated calls may change based on any changes to current policies and regulations pertaining to disconnections
Cost per Credit FTE ($)	$73,382	Company cost data	Labor costs may increase at a rate faster than 2% inflation
One-Time IVR Optimization ($)	$300,000	Company estimate	The cost to optimize IVR could be understated and increase faster than 2% inflation
Incremental Telephony Budget Increase ($)	$50,000	Company estimate	The budget increase could understate the need for enhanced data transmission capabilities, upgraded network infrastructure, and integration with existing systems.
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation Rate (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

	Capital			
	Internal Labor	Corporate Overhead	Contingency	Total Capital
Year 1	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.32	$0.30	$0.03	**$0.65**
Year 4	$0.00	$0.00	$0.00	**$0.00**
Year 5	$0.00	$0.00	$0.00	**$0.00**
Year 6	$0.00	$0.00	$0.00	**$0.00**
Year 7	$0.00	$0.00	$0.00	**$0.00**
Year 8	$0.00	$0.00	$0.00	**$0.00**
Year 9	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$0.32**	**$0.30**	**$0.03**	**$0.65**
20-Year NPV	**$0.26**	**$0.24**	**$0.03**	**$0.53**

	O&M					Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 3	$5.80	$6.23	$5.42	$1.20	**$18.66**	**$19.31**
Year 4	$5.95	$4.77	$5.53	$1.07	**$17.31**	**$17.31**
Year 5	$4.40	$4.62	$4.07	$0.90	**$13.99**	**$13.99**
Year 6	$0.06	$4.71	$0.00	$0.48	**$5.24**	**$5.24**
Year 7	$0.06	$4.80	$0.00	$0.49	**$5.35**	**$5.35**
Year 8	$0.06	$4.90	$0.00	$0.50	**$5.46**	**$5.46**
Year 9	$0.06	$5.00	$0.00	$0.51	**$5.56**	**$5.56**
Year 10	$0.06	$5.10	$0.00	$0.52	**$5.68**	**$5.68**
Year 11	$0.06	$5.20	$0.00	$0.53	**$5.79**	**$5.79**
Year 12	$0.06	$5.30	$0.00	$0.54	**$5.91**	**$5.91**
Year 13	$0.06	$5.41	$0.00	$0.55	**$6.02**	**$6.02**
Year 14	$0.07	$5.52	$0.00	$0.56	**$6.14**	**$6.14**
Year 15	$0.07	$5.63	$0.00	$0.57	**$6.27**	**$6.27**
Year 16	$0.07	$5.74	$0.00	$0.58	**$6.39**	**$6.39**
Year 17	$0.07	$5.86	$0.00	$0.59	**$6.52**	**$6.52**

	O&M					Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	O&M Total	
Year 18	$0.07	$5.97	$0.00	$0.60	**$6.65**	**$6.65**
Year 19	$0.07	$6.09	$0.00	$0.62	**$6.78**	**$6.78**
Year 20	$0.07	$6.22	$0.00	$0.63	**$6.92**	**$6.92**
20-Year Total	**$17.12**	**$97.07**	**$15.02**	**$11.42**	**$140.64**	**$141.29**
20-Year NPV	**$12.82**	**$46.42**	**$11.55**	**$5.92**	**$76.71**	**$77.24**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(iii) Incremental Labor

a. Description

Implementation of an AMI system will require significant and diverse incremental labor resources. Each of the cost categories quantified in the BCA Report will require incremental labor resources to support an effective and successful implementation of the AMI meters and the associated IT applications.

Figure 12 describes the labor requirements by category. The associated labor costs are included in their respective cost category.

Figure 12 – Incremental Labor By Cost Category

Cost	Average Pre-and During Deployment FTEs (Year 1 - Year 6)	Average Post Deployment FTEs (Year 7 - Year 19)
Meters	70	54
Communications Upgrades	7	5
Meter Data Management System (MDMS)	41	14
Customer Information System (CIS)	52	32
Organizational Readiness	44	0
Contact Center	85	57
OMS Integration	1	0
Customer Experience Portal	15	0
VVO Enablement	4	13
Engineering and Customer Usage Analytics	15	1
Customer Engagement	3	4

Cost	Average Pre-and During Deployment FTEs (Year 1 - Year 6)	Average Post Deployment FTEs (Year 7 - Year 19)
Cybersecurity	12	3
Revenue Assurance (Non-Technical Line Loss)	6	2
Green Button Connect	1	0
Data Storage and Processing	0	0
Load Settlement	11	1
Grand Total	**367**	**189**

Incremental Labor resources support all of the benefits described in this report based on the labor required in each investment category. These enabled benefits are listed in each individual investment category based on the specific benefits enabled.

b. Cost Calculation Methodology

Incremental Labor costs are calculated as labor costs within the applicable sections shown in Figure 12. These calculations are shown within each applicable cost section.

c. Annual Cost Calculation and Cost Granularity

Incremental Labor costs are calculated as labor costs within the applicable sections shown in Figure 12. These annual cost calculations are shown within each applicable cost section.

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(iv) Revenue Assurance (Non-Technical Line Loss)

a. Description

The Company anticipates additional costs to fully enable the revenue assurance benefits described in Section B.7.ii. - Reduced Theft and Non-Technical Line Loss. Specifically, additional resources will be needed to investigate the increase in identified unbilled usage. As described previously, the Company expects to use customer usage data and the tamper detection capabilities of AMI meters to better identify and address unbilled usage. With the increase in identified unbilled usage through revenue assurance analytics, the Company will need to hire additional revenue assurance investigators to fully realize the unbilled usage benefit from revenue recovered and 12-month avoided loss. The cost of the revenue assurance analytics is captured in Section D.5.iii. – Engineering and Customer Usage Analytics.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The Company anticipates hiring 8 incremental revenue assurance investigators and 2 supporting staff (including supervisors, instructor designers, and trainers) between Year 3 and Year 6, to support the initial influx of revenue assurance identification from deployment of AMI, reaching steady state after Year 6. Each incremental revenue assurance investigator requires one-time material and equipment costs upon hiring, and ongoing annual equipment costs.

Revenue Assurance O&M Cost Calculations:

Revenue Assurance Resources - Labor									
Number of Incremental Revenue Assurance Resources Hired	X	Revenue Assurance Resources Average Labor Rate ($/year)	X	Labor Overhead (%)	X	Contingency (%)	X	Inflation (%)
10		$113,000		96%		10%		2%

Revenue Assurance Investigators - Materials and Equipment - One-time						
One Time Revenue Assurance Investigator Materials and Equipment ($/investigator)	X	Incremental Revenue Assurance Investigators Hired per year	X	Contingency (%)	X	Inflation (%)
$16,400		2		10%		2%

Revenue Assurance Investigators - Ongoing Materials and Equipment						
Annual Revenue Assurance Investigator Materials and Equipment ($/year)	X	Number of Incremental Revenue Assurance Investigators Hired		Contingency (%)	X	Inflation (%)
$500		10		10%		2%

Revenue Assurance List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Revenue Assurance Resources Average Labor Rate ($/year)	$113,000	Company cost estimate	Labor may increase a rate faster than 2% inflation
Incremental Revenue Assurance Resources Hired	10	Ranges one incremental revenue assurance investigator in year 1 of AMI deployment to 10 incremental at end of deployment and 2	The number of revenue assurance investigators may scale up or down differently than projected. The number of peak revenue assurance investigators is from Year 3 to Year 5 but it could shift or have a faster or slower ramp down to steady
Incremental Revenue Assurance Investigators Hired per year	2		

		years post-AMI deployment.	state depending on the amount of revenue assurance identified by the revenue assurance analytics software
One Time Revenue Assurance Investigator Materials and Equipment ($/investigator)	$16,400	Company cost estimate	Material cost may increase a rate faster than 2% inflation
Annual Revenue Assurance Investigator Materials and Equipment ($/year)	$500		
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Annual AMI Meters Deployed (%)	17%-100%	Starting in mid-Year 3, 17% of all meters are expected to be deployed, 50% by end of Year 4, 83% by end of Year 5, and 100% by mid-Year 6	AMI meters deployed could be greater than or less than the annual projections

c. Annual Cost Calculation and Cost Granularity

	Capital			O&M					Total
	Materials	Contingency	Total Capital	Internal Labor	Materials	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	**$0.00**	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.02	$0.00	**$0.02**	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.02**
Year 3	$0.00	$0.00	**$0.00**	$0.11	$0.00	$0.10	$0.01	**$0.23**	**$0.23**
Year 4	$0.06	$0.01	**$0.06**	$0.58	$0.00	$0.54	$0.06	**$1.18**	**$1.24**
Year 5	$0.06	$0.01	**$0.06**	$0.99	$0.00	$0.93	$0.10	**$2.03**	**$2.09**
Year 6	$0.02	$0.00	**$0.03**	$1.19	$0.00	$1.12	$0.12	**$2.43**	**$2.45**
Year 7	$0.00	$0.00	**$0.01**	$1.21	$0.00	$1.14	$0.12	**$2.48**	**$2.48**
Year 8	$0.00	$0.00	**$0.01**	$1.24	$0.00	$1.16	$0.12	**$2.53**	**$2.53**
Year 9	$0.00	$0.00	**$0.01**	$1.26	$0.00	$1.19	$0.13	**$2.58**	**$2.58**
Year 10	$0.00	$0.00	**$0.01**	$1.29	$0.00	$1.21	$0.13	**$2.63**	**$2.64**
Year 11	$0.00	$0.00	**$0.01**	$1.31	$0.00	$1.24	$0.13	**$2.68**	**$2.69**

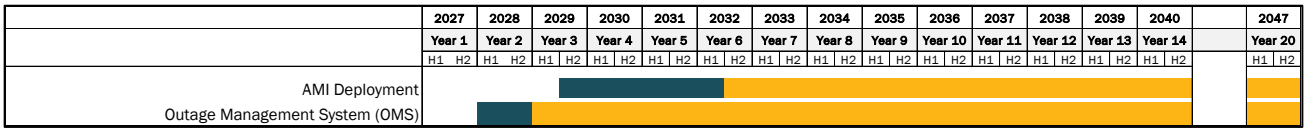
	Capital			O&M					Total
	Materials	Contingency	Total Capital	Internal Labor	Materials	Corporate Overhead	Contingency	O&M Total	
Year 12	$0.01	$0.00	**$0.01**	$1.34	$0.00	$1.26	$0.13	**$2.74**	**$2.74**
Year 13	$0.01	$0.00	**$0.01**	$1.37	$0.00	$1.29	$0.14	**$2.79**	**$2.80**
Year 14	$0.01	$0.00	**$0.01**	$1.40	$0.00	$1.31	$0.14	**$2.85**	**$2.85**
Year 15	$0.01	$0.00	**$0.01**	$1.42	$0.00	$1.34	$0.14	**$2.90**	**$2.91**
Year 16	$0.01	$0.00	**$0.01**	$1.45	$0.00	$1.36	$0.15	**$2.96**	**$2.97**
Year 17	$0.01	$0.00	**$0.01**	$1.48	$0.00	$1.39	$0.15	**$3.02**	**$3.03**
Year 18	$0.01	$0.00	**$0.01**	$1.51	$0.00	$1.42	$0.15	**$3.08**	**$3.09**
Year 19	$0.00	$0.00	**$0.00**	$1.54	$0.00	$1.45	$0.15	**$3.14**	**$3.14**
Year 20	$0.00	$0.00	**$0.00**	$1.57	$0.00	$1.48	$0.16	**$3.21**	**$3.21**
20-Year Total	**$0.22**	**$0.02**	**$0.25**	**$22.28**	**$0.00**	**$20.94**	**$2.23**	**$45.44**	**$45.69**
20-Year NPV	**$0.15**	**$0.01**	**$0.16**	**$9.94**	**$0.00**	**$9.34**	**$0.99**	**$20.27**	**$20.43**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.5 SUPPORTING SERVICES AND PLATFORMS

(i) Outage Management System (OMS) Integration



a. Description

First generation AMI systems required a system to process and filter AMI outage data to avoid overwhelming the utility OMS during large scale outage events with individual meter outage notifications, a function that was typically performed by the MDMS. Modern AMI systems utilize HES that have the capability to process and filter AMI outage data or DI analytics to perform automated outage analysis with meters at the grid edge. This pre-processed outage data has precise outage information that is transmitted back to the HES and fed to the OMS, improving the Company's ability to respond to outages.

The Company's existing OMS solution has the capability to interface with the AMI HES, facilitated by an enterprise data service bus. Enhancements and integration to the OMS are required to ingest data from the HES and support blue-sky and storm operations, all to improve system reliability and resiliency.

As part of the OMS integration for the program, the Company intends to upgrade the OMS to further enhance its ability to integrate and enable AMI use cases. This upgrade, which is expected to be available in Year 2, will provide advanced features and capabilities to better support the ingestion and

analysis of data from the HES. The upgraded OMS will offer improved analytics, more robust reporting tools, and enhanced operational efficiency, which will significantly boost the system's reliability and resiliency.

The OMS will receive data from the HES to perform additional analytics and internal analytical resources will develop operational reports to enhance outage prediction and restoration. The benefits of enabling remote interrogation of meters through integration with the Company's OMS is expected to be greatest in major, multi-day events with extensive numbers of trouble spots. In these events, power is restored first to the system backbone. Typically, this leaves smaller pockets of outages undetected for a period, limiting the efficiency of restoration at the tail end of the event. With an integrated OMS, AMI is expected to improve reliability for these nested outages at the tail end of major events, by providing visibility into where these outages are and allowing the Company to restore service more quickly.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

Outage response improvement is expected to be available following integration of the MDMS and the OMS, which will occur in mid-Year 2. The Company can remotely ping all installed AMI meters as a part of the restoration process. This integration will ensure that the Company is notified of the customer's outage status immediately on loss of supply regardless of whether the customer reports the outage to the Company. The cost drivers for this investment are the internal and external labor needed to integrate the AMI and OMS systems and ongoing annual software O&M.

<u>Capital Cost Calculations</u>:

OMS Integration - Internal Labor Calculation:						
AMI to OMS Labor - Internal ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$684,660		2%		20%		94%

OMS Integration - External Labor Calculation:				
AMI to OMS Labor - External ($)	X	Inflation (%)	X	Contingency (%)
$7,884,607		2%		20%

<u>O&M Cost Calculations</u>:

OMS Integration - Ongoing Software O&M Calculation:				
AMI to OMS – Annual Maintenance ($)	X	Inflation (%)	X	Contingency (%)
$170,000		2%		20%

Outage Management System (OMS) Integration List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
AMI to OMS Labor - External ($)	$7,884,607	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut	12-month implementation beginning in mid-Year 2 and completing before AMI deployment in mid-Year 3. Current cost estimates could increase at a rate faster than 2% inflation or additional internal or external labor could be required. Depending on final vendor selection and approach for OMS, costs and implementation duration may be higher than currently estimated.
AMI to OMS Labor - Internal ($)	$684,660	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut, including allocation amount for Massachusetts	
AMI to OMS – Annual Maintenance ($)	$170,000	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut	Ongoing costs may increase faster than 2%
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

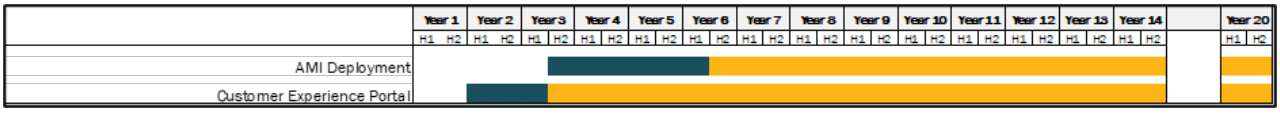
	Capital						O&M			Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	AFUDC	Total Capital	Software Licensing / Fees	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.71	$8.20	$0.67	$0.89	$0.65	**$11.13**	$0.18	$0.02	**$0.19**	**$11.32**
Year 3	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 4	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 5	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 6	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**

	Capital						O&M			Total
	Internal Labor	External Labor	Corporate Overhead	Contingency	AFUDC	Total Capital	Software Licensing / Fees	Contingency	O&M Total	
Year 7	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 8	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.18	$0.02	**$0.19**	**$0.19**
20-Year Total	**$0.71**	**$8.20**	**$0.67**	**$0.89**	**$0.65**	**$11.13**	**$3.36**	**$0.34**	**$3.70**	**$14.82**
20-Year NPV	**$0.62**	**$7.16**	**$0.58**	**$0.78**	**$0.57**	**$9.72**	**$1.71**	**$0.17**	**$1.88**	**$11.60**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(ii) Customer Experience Portal



a. Description

Eversource is committed to creating value for its customers by developing an enhanced web portal (with an accompanying mobile application) to provide access to granular energy usage data. The costs outlined here, related to that effort, will enable customers to leverage this information to gain insights about their energy use and turn those insights into action.

Portal functionality will be tailored to specific customer segments such as residential, small business, or large commercial and optimized for viewing on a range of devices (e.g. mobile phones, tablets). This program includes the implementation of advanced web technologies and will ensure that customers can easily find and access information in a simple, intuitive manner. To ensure a consistent omni-channel experience, customer call center employees will also have access to the portal, allowing them to better serve customers by seeing exactly what the customer is seeing.

The portal is expected to enable the following functionalities:

- Provide more transparent, real-time data for customers to act on, allowing the Company to seamlessly deliver the right value-added program/message to the right customer at the right time related to their energy account and usage.
- Provide insights related to usage behavior, patterns, and trends, as well as energy savings tips and personalized action plans to conserve and save.
- Provide the ability to overlay additional data in graphical format, including weather, price, and billing data.
- Provide the ability for customers to understand how and when their energy is being used and what appliances are using the most electricity.
- Provide tools that will demonstrate the impact that an adjustment to their energy usage made in one or more areas will have on their costs.
- Provide customers with proactive alerts associated with projected billing, home energy use, and customized thresholds set by customers.
- Provide the ability for customers to schedule the delivery of energy usage reports on an ongoing basis.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The Company estimated customer experience based on actual upfront and ongoing costs and vendor costs for the Massachusetts AMI Program and scaled and repurposed as estimates for Connecticut. Key costs include internal labor, upfront outside contracting services, ongoing outside services, and ongoing system SaaS fees.

<u>Capital Cost Calculations</u>:

Customer Experience Portal - External Cost Calculation:				
CX Portal – External Labor ($)	X	Inflation (%)	X	Contingency (%)
$19,290,834		2%		20%

Customer Experience Portal - Upfront Internal Labor Cost Calculation:								
CX Portal - Testing CoE ($)	+	CX Portal - Internal Labor ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$237,183		$1,258,776		2%		20%		94%

Customer Experience Portal - Upfront Software Cost Calculation (Capital):				
CX Portal – Upfront SaaS Development ($)	X	Inflation (%)	X	Contingency (%)
$4,432,027		2%		20%

O&M Cost Calculations:

Customer Experience Portal - Training Cost Calculation (O&M):						
CX Portal – Training ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$680,000		2%		20%		94%

Customer Experience Portal - License Cost Calculation (O&M):				
O&M Annual System SaaS Fee ($)	X	Inflation (%)	X	Contingency (%)
Confidential		2%		20%

Customer Experience Portal List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
CX Portal – External Labor ($)	$19,290,834	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut and spread over a 3-year implementation, including an allocation amount for Massachusetts	Current pricing estimates are subject to negotiation and may increase faster than 2% inflation
CX Portal - Testing Center of Excellence ($)	$237,183		
CX Portal - Upfront SaaS Development ($)	$4,432,027		
CX Portal - Internal Labor ($)	$1,258,776		
CX Portal – One-time Training ($)	$680,000	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut and spread over 6 years	
O&M Annual System SaaS Fee ($)	Confidential	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut and assumes	
System Contract Duration (# Year)	5		

Customer Experience Portal List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
		contract renews every 5 years and increases with inflation	
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

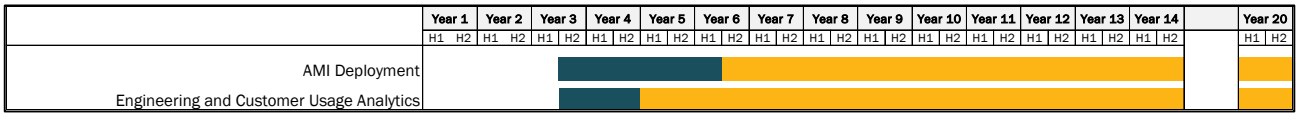
		Capital						
	Internal Labor	External Labor	Materials	Software	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.52	$0.46	$2.46	$3.77	$0.49	$1.44	$0.57	**$9.71**
Year 3	$1.06	$0.95	$5.02	$7.68	$0.99	$2.94	$1.16	**$19.80**
Year 4	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 7	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 8	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$1.58**	**$1.41**	**$7.48**	**$11.45**	**$1.48**	**$4.38**	**$1.73**	**$29.51**
20-Year NPV	**$1.32**	**$1.18**	**$6.24**	**$9.56**	**$1.24**	**$3.66**	**$1.44**	**$24.64**

	O&M					Total
	Internal Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.71	$0.00	$0.67	$0.14	**$1.51**	**$11.22**
Year 3	$0.00	$3.31	$0.00	$0.66	**$3.97**	**$23.77**
Year 4	$0.00	$3.37	$0.00	$0.67	**$4.05**	**$4.05**
Year 5	$0.00	$3.44	$0.00	$0.69	**$4.13**	**$4.13**
Year 6	$0.00	$3.51	$0.00	$0.70	**$4.21**	**$4.21**
Year 7	$0.00	$3.58	$0.00	$0.72	**$4.29**	**$4.29**
Year 8	$0.00	$3.65	$0.00	$0.73	**$4.38**	**$4.38**
Year 9	$0.00	$3.72	$0.00	$0.74	**$4.47**	**$4.47**
Year 10	$0.00	$3.80	$0.00	$0.76	**$4.56**	**$4.56**
Year 11	$0.00	$3.87	$0.00	$0.77	**$4.65**	**$4.65**
Year 12	$0.00	$3.95	$0.00	$0.79	**$4.74**	**$4.74**
Year 13	$0.00	$4.03	$0.00	$0.81	**$4.84**	**$4.84**
Year 14	$0.00	$4.11	$0.00	$0.82	**$4.93**	**$4.93**
Year 15	$0.00	$4.19	$0.00	$0.84	**$5.03**	**$5.03**
Year 16	$0.00	$4.28	$0.00	$0.86	**$5.13**	**$5.13**
Year 17	$0.00	$4.36	$0.00	$0.87	**$5.24**	**$5.24**
Year 18	$0.00	$4.45	$0.00	$0.89	**$5.34**	**$5.34**
Year 19	$0.00	$4.54	$0.00	$0.91	**$5.45**	**$5.45**
Year 20	$0.00	$4.63	$0.00	$0.93	**$5.56**	**$5.56**
20-Year Total	**$0.71**	**$70.80**	**$0.67**	**$14.30**	**$86.48**	**$115.98**
20-Year NPV	**$0.62**	**$33.35**	**$0.58**	**$6.79**	**$41.35**	**$65.99**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(iii) Engineering and Customer Usage Analytics



a. Description

Much of the anticipated value proposition of AMI involves the analysis of interval data to support engineering and customer related benefits. The costs required to achieve these benefits include data storage; software and coding; hardware; and integrations with supporting IT systems. Additional costs are associated with ongoing data and storage costs, systems maintenance, licensing, and production support labor. Although there are several high-value use cases for AMI data analytics, the Company

focused on five opportunities: (1) voltage measurements in support of VVO; (2) theft detection algorithms; (3) improved transformer load monitoring ("TLM"); (4) TOU/TVR rate design analysis, (5) load research, and (6) energy efficiency and demand management. The outcome of these use cases is expected to provide additional qualitative benefits for long, mid- and short-term planning and load forecasting. Lastly, asset management costs are included to manage the new set of AMI meters and communications assets.

Additionally, the Company plans to run a high impedance detection for distributed intelligence pilot. This pilot will leverage grid-edge data from AMI to identify potential high impedance fault conditions or abnormal system behavior that may not be visible through traditional monitoring approaches, supporting improved situational awareness, faster investigation, and reduced risk associated with undetected equipment issues on the distribution system.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The costs to enable engineering and customer data analytics were estimated based on the assumption that the Company would leverage its internal data analytics platform and data analytics Center of Excellence to drive the expected outcomes of each use case. The Company's estimated costs associated with implementation labor; hardware and software; ongoing support labor; and ongoing hardware and software costs. Costs for data storage were estimated based on an assumption of the quantity of data storage required to support all six of the analytics use cases noted within this section. All costs reflect an assumption that all meters will have a degree of native distributed intelligence capabilities which will reduce the cost and complexity of in-house data analytics efforts. In some cases, it is possible that meters can perform additional distributed intelligence on-meter calculations to increase the efficiency and effectiveness of analytics activities, at an additional cost. These opportunities will be pursued to the extent that they are accretive to the overall value proposition for customers.

Starting mid-way through Year 3, following MVP system deployment, the Company will develop Engineering and Customer Usage analytics focused on: (1) VVO; (2) theft detection; (3) improved transformer load monitoring ("TLM"); (4) TOU/TVR rate design analysis; (5) load research, and (6) energy efficiency and demand management. All back-end development will be completed by early Year 4 and the six use cases begin development thereafter completing all by the end of Year 4 and will support the realization of associated benefits as customer meters are deployed, or, in the case of VVO, as necessary upgrades are completed. Capital and O&M costs to support data, licensing, and labor for these analytics continues through the 20-year project timeline.

For high impedance detection for distributed intelligence pilot, the cost estimate includes ongoing licensing fees associated with a pilot deployment of the DI solution. These licensing costs are calculated on a per-meter basis and applied only to the number of meters assumed to be deployed during the five-year pilot period starting 1 year after the start of meter deployment.

Asset management costs were estimated based on the current assumptions for asset management needs, which will be finalized contingent on approval of the AMI Plan.

Capital Cost Calculations:

Analytics - Back-End Development External Cost Calculation:						
Analytics Core Analytics Implementation ($)	+	Analytics Advanced Use Case Implementation ($)	X	Inflation (%)	X	Contingency (%)
$4,655,348		$7,392,047		2%		20%

Analytics - Back-End Development Internal Cost Calculation:				
Analytics Internal Labor ($)	X Inflation (%) X	Contingency (%)	X	Labor Overhead (%)
$1,210,630	2%	20%		94%

Analytics - Annual AMI Software Contract Cost Calculation (Capital):				
Analytics Software-as-a-Service ($)	X	Inflation (%)	X	Contingency (%)
$4,439,749		2%		20%

Asset Management (System Upgrades) - External Labor Cost Calculation:				
Asset Management External Labor ($)	X	Inflation (%)	X	Contingency (%)
$780,300		2%		20%

Asset Management (System Upgrades) - Internal Labor Cost Calculation:						
Asset Management Internal Labor ($)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
$780,300		2%		20%		94%

Analytics – Upfront Data and Storage Cost Calculation:						
Analytics - Annual Ongoing Data & Storage Costs ($)	X	Analytics Implementation Duration (Years)	X	Inflation (%)	X	Contingency (%)
$838,169		1.5		2%		20%

O&M Cost Calculations:

Analytics – Ongoing Data Storage and Software Licensing Cost Calculation:						
Analytics - Ongoing SaaS Costs	+	Analytics - Ongoing Data and Storage Costs	X	Inflation (%)	X	Contingency (%)
$1,307,256		$838,169		2%		20%

High Impedance Detection for Distributed Intelligence – Pilot Implementation Licensing and Fees Cost Calculation:							
High Impedance Detection for Distributed Intelligence ($ per Meter)	X	Average Number of AMI Meters Per Year (#)	X	Inflation (%)	X	Contingency (%)	
Confidential		1,396,183		2%		20%	

Engineering and Customer Usage Analytics List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Analytics Core Analytics Implementation ($)	$4,655,348	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut, including an allocation amount for Massachusetts	Implementation for each use case is 6 months beginning after EDP is complete in mid-Year 3. Any delays implementing use cases impacts associated benefit realization
Analytics Advanced Use Case Implementation ($)	$7,392,047		
Analytics Software-as-a-Service ($)	$4,439,749		
Analytics Internal Labor ($)	$1,210,630		
Analytics Implementation Duration (Years)	1.5	Company estimate	Implementation duration may be longer or shorter than estimated
Analytics - Ongoing Data and Storage Costs ($)	$838,169	Cost data from Massachusetts AMI Program and repurposed as estimates for Connecticut, including an allocation amount for Massachusetts	Actual costs may rise by more than inflation.
Analytics - Annual AMI Software Contract Cost Calculation ($)	$1,307,256		
High Impedance Detection for Distributed Intelligence ($ per Meter)	Confidential	Massachusetts contract with vendor and repurposed as estimates for Connecticut	Actual costs may rise by more than inflation.
Average Meters for Analytics Software Platform Per Year (#)	1,396,183	Company estimate	1.5% meter growth may overstate or understate the number of total AMI meters in the system over the next 20 years
Asset Management (system upgrades) - External Costs ($)	$780,300	Company estimate	Implementation over 4 years during AMI deployment. Cost estimates may increase at a rate faster than 2% inflation before implementation is expected

Asset Management (system upgrades) - Internal Costs ($)	$780,300	Company estimate	Implementation over 4 years during AMI deployment. Cost estimates may increase at a rate faster than 2% inflation before implementation is expected
Average Meters Needing Analytics Software Platform Per Year (#)	1,396,183	Assumes 1.5% annual meter growth	1.5% meter growth may overstate or understate the number of total AMI meters in the system over the next 20 years
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

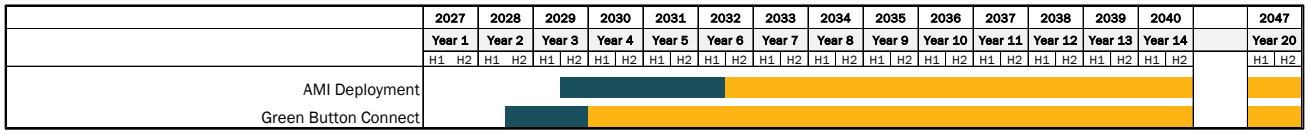
	Capital						
	Internal Labor	External Labor	Software	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.57	$4.40	$1.57	$0.13	$0.06	$0.03	**$6.75**
Year 4	$1.16	$8.98	$3.20	$0.26	$0.11	$0.06	**$13.77**
Year 5	$0.29	$0.29	$0.00	$0.27	$0.11	$0.06	**$1.02**
Year 6	$0.15	$0.15	$0.00	$0.14	$0.06	$0.03	**$0.52**
Year 7	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 8	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$2.16**	**$13.81**	**$4.77**	**$0.80**	**$0.34**	**$0.18**	**$22.06**
20-Year NPV	**$1.65**	**$10.74**	**$3.73**	**$0.59**	**$0.25**	**$0.13**	**$17.09**

	O&M			Total
	Software Licensing / Fees	Contingency	O&M Total	
Year 1	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.00	$0.00	**$0.00**	**$0.00**
Year 3	$0.00	$0.00	**$0.00**	**$6.75**
Year 4	$0.00	$0.00	**$0.00**	**$13.77**
Year 5	$3.69	$0.74	**$4.43**	**$5.45**
Year 6	$4.05	$0.81	**$4.86**	**$5.38**
Year 7	$4.16	$0.83	**$4.99**	**$4.99**
Year 8	$4.26	$0.85	**$5.12**	**$5.12**
Year 9	$4.38	$0.88	**$5.25**	**$5.25**
Year 10	$2.62	$0.52	**$3.14**	**$3.14**
Year 11	$2.67	$0.53	**$3.20**	**$3.20**
Year 12	$2.72	$0.54	**$3.27**	**$3.27**
Year 13	$2.78	$0.56	**$3.33**	**$3.33**
Year 14	$2.83	$0.57	**$3.40**	**$3.40**
Year 15	$2.89	$0.58	**$3.46**	**$3.46**
Year 16	$2.95	$0.59	**$3.53**	**$3.53**
Year 17	$3.00	$0.60	**$3.60**	**$3.60**
Year 18	$3.06	$0.61	**$3.68**	**$3.68**
Year 19	$3.13	$0.63	**$3.75**	**$3.75**
Year 20	$3.19	$0.64	**$3.83**	**$3.83**
20-Year Total	**$52.36**	**$10.47**	**$62.84**	**$84.89**
20-Year NPV	**$24.43**	**$4.89**	**$29.31**	**$46.40**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(iv) Green Button Connect



Green Button Connect is a standardized initiative that enables utility customers to securely share their energy usage data with third-party providers of energy products, applications and services, improving customers' ability to manage energy consumption. Green Button Connect enhances customers' AMI experience by providing detailed, real-time energy usage data that can be easily accessed and shared, empowering consumers with actionable insights and fostering energy efficiency.

The Company plans to develop a Green Button Connect Platform to facilitate secure data sharing with authorized third-parties. This platform will leverage enhanced data capabilities to offer

customers data-driven services, programs, and platforms, thereby digitally empowering customers to securely transfer their data to third-party solution providers. These providers can assist customers in monitoring and managing their energy usage - offering a range of services such as online viewing, analysis, energy efficiency (EE) opportunities, DER program opportunities, and more.

The Company intends to implement the Platform at approximately the same time as AMI deployment begins. The Platform cannot be implemented prior to AMI deployment, as there needs to be some AMI data sent to the Platform for it to be fully enabled. Third party data sharing will only be available for customers with an AMI meter.

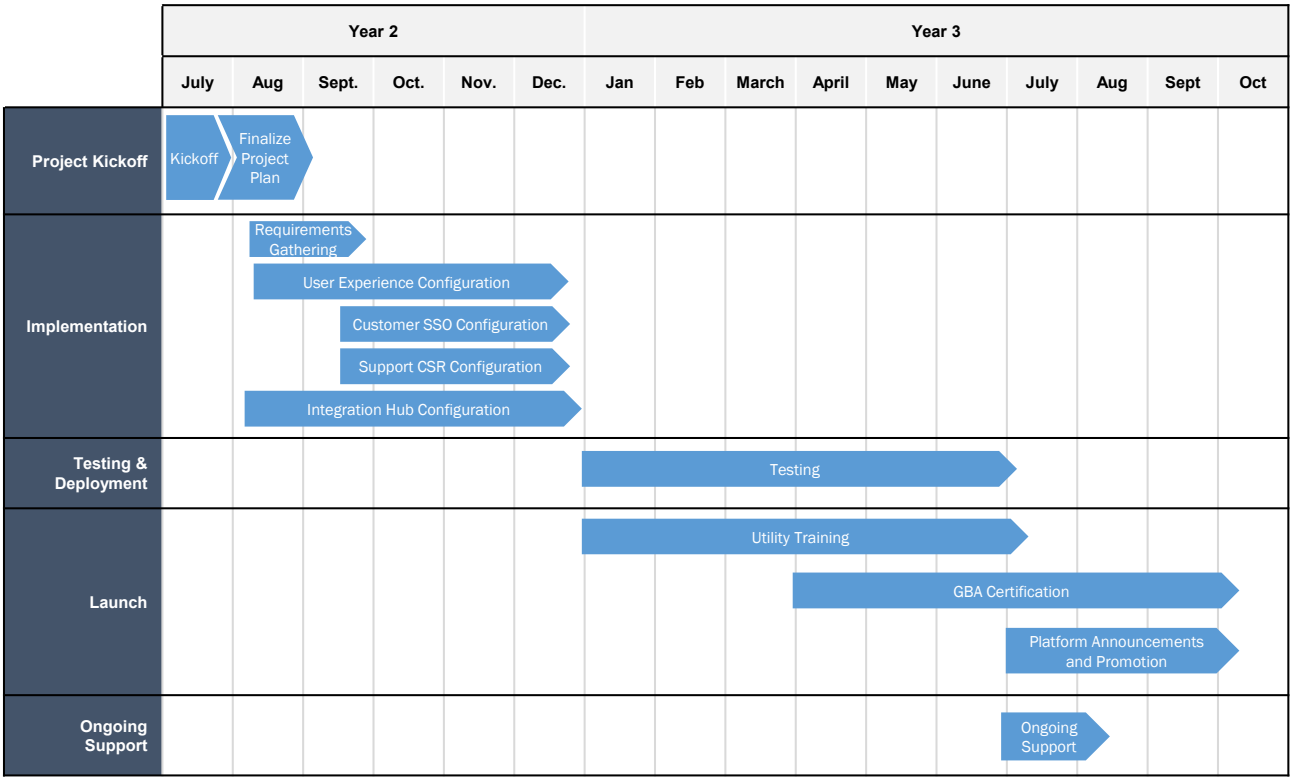
Once the Platform is deployed, the Company will start enrolling third-parties. Third-parties will be able to become approved data recipients with the Company by first registering with the Platform and completing a self-attestation statement. Each application is reviewed by the Company to ensure the third-party meets the cyber security standards established for third-party data sharing. The Company will establish Service Level Agreements (SLAs) to provide guidance on how long the internal approval process may take. Once approved by the Company, third-parties will be able to submit direct requests to individual customers for authorization to access their data.

The Company will promote the deployment of the Platform so that third-parties will know that they can register. While the Company expects an influx of third-party applications at the time of deployment, the third-party enrollment process will occur on a rolling basis, and third-parties will be able to register at any time after deployment.

Once the Platform is implemented, the Company will seek Green Button Connect Certification from the Green Button Alliance. Based on the Company's experience in Massachusetts, the Green Button Connect Certification should take 4-6 months from deployment.

Figure 13 shows the Company's proposed deployment schedule for Green Button Connect which is expected to take place over approximately 17 months between Year 2 and Year 3 and be completed approximately when AMI deployment begins in mid-Year 3. The timeline mirrors the Company's Green Button Connect implementation timeline currently in-flight in Massachusetts as part of the AMI Program.

Figure 13 – Green Button Connect Timeline



Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The Company anticipates using the Green Button Connect functionality that will already be in place for its Massachusetts territories and will leverage efficiencies where possible. The below section describes the incremental costs expected to support Green Button Connect functionality. The Company sourced all cost estimates from its Massachusetts Green Button Connect implementation vendor and scaled costs where possible based on meter population. The total upfront implementation fee for the Green Button Connect system distributed across five milestones: project plan integration, beta readiness for system integration testing (SIT) and user acceptance testing (UAT), full deployment and certification, first use by an accountholder, and system acceptance. Hosting fees ensure the reliable, secure, and efficient operation of the Green Button Connect service while Bulk Upload fees are the costs associated with the infrastructure, processing, and management required to handle large-scale uploads of energy usage data from utility AMI meters to the Green Button Connect platform. Both ongoing SaaS fees are charged on per meter basis and will ramp up as more AMI meters are deployed.

Capital Cost Calculations:

Green Button Connect - Upfront Implementation Costs Calculation:				
Upfront Implementation ($)	X	Contingency (%)	X	Inflation (%)
$570,000		20%		2%

Green Button Connect - Upfront Bulk Upload Costs Calculation:				
Upfront Bulk Upload ($)	X	Contingency (%)	X	Inflation (%)
$115,000		20%		2%

O&M Cost Calculations:

Green Button Connect - Ongoing Hosting SaaS Fees Costs Calculation:						
Average Number of AMI Meters from Year 1 - Year 20	X	Average Ongoing Hosting SaaS Fees Per AMI Meter ($)	X	Contingency (%)	X	Inflation (%)
1,497,648		Confidential		20%		2%

Green Button Connect - Ongoing Hosting SaaS Fees for Bulk Upload Costs Calculation:						
Average Number of AMI Meters from Year 1 - Year 20	X	Average Ongoing SaaS Hosting Fees for Bulk Upload per AMI Meter ($)	X	Contingency (%)	X	Inflation (%)
1,497,648		Confidential		20%		2%

Green Button Connect List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Upfront Implementation ($)	$570,000	Cost estimates based on actual Massachusetts AMI Program cost data scaled to Connecticut based on number of meters, including an allocation amount for Massachusetts	Cost estimates may increase at a rate faster than inflation before implementation is expected
Upfront Bulk Upload ($)	$115,000		
Implementation Duration (Months)	17	Company estimate based on Massachusetts AMI Program	Implementation could take longer than 17 months, impacting costs
Average Ongoing Hosting SaaS Fees Per AMI Meter ($)	Confidential	Estimates provided by Vendor for Connecticut	Ranges from the first year of deployment to steady state per meter. Begins after Green

Green Button Connect List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
			Button Connect implementation completes. Price estimate could increase faster than 2%
Average Ongoing SaaS Hosting Fees for Bulk Upload per AMI Meter ($)	Confidential	Estimates provided by Massachusetts system implementation vendor for Connecticut	Begins after Green Button Connect implementation completes. Price estimate could increase faster than 2%
Average Number of AMI Meters from Year 1-Year 20	1,497,648	Assumes 1.5% annual meter growth	1.5% meter growth may overstate or understate the number of total AMI meters in the system over the next 20 years
Contingency (%)	20%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

	Capital					O&M			Total
	External Labor	Software	Contingency	AFUDC	Total Capital	Software Licensing / Fees	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**	**$0.00**
Year 2	$0.00	$0.00	$0.07	$0.00	**$0.00**	$0.00	$0.00	**$0.00**	**$0.00**
Year 3	$0.30	$0.06	$0.07	$0.01	**$0.45**	$0.11	$0.02	**$0.13**	**$0.58**
Year 4	$0.30	$0.06	$0.07	$0.01	**$0.46**	$0.32	$0.06	**$0.38**	**$0.84**
Year 5	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.55	$0.11	**$0.65**	**$0.65**
Year 6	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.69	$0.14	**$0.82**	**$0.82**
Year 7	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.72	$0.14	**$0.86**	**$0.86**
Year 8	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.73	$0.15	**$0.87**	**$0.87**
Year 9	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.74	$0.15	**$0.89**	**$0.89**
Year 10	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.75	$0.15	**$0.90**	**$0.90**
Year 11	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.76	$0.15	**$0.91**	**$0.91**
Year 12	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.77	$0.15	**$0.93**	**$0.93**
Year 13	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.78	$0.16	**$0.94**	**$0.94**
Year 14	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.79	$0.16	**$0.95**	**$0.95**
Year 15	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.81	$0.16	**$0.97**	**$0.97**
Year 16	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.82	$0.16	**$0.98**	**$0.98**

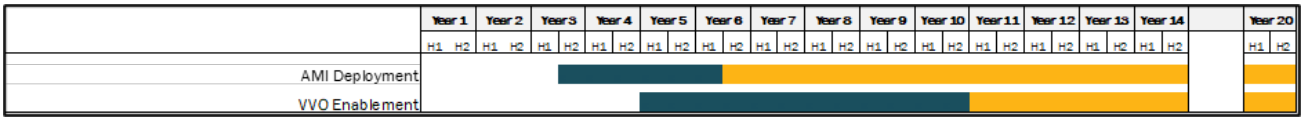
	Capital					O&M			
	External Labor	Software	Contingency	AFUDC	Total Capital	Software Licensing / Fees	Contingency	O&M Total	Total
Year 17	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.83	$0.17	**$1.00**	**$1.00**
Year 18	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.84	$0.17	**$1.01**	**$1.01**
Year 19	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.86	$0.17	**$1.03**	**$1.03**
Year 20	$0.00	$0.00	$0.00	$0.00	**$0.00**	$0.87	$0.17	**$1.04**	**$1.04**
20-Year Total	**$0.60**	**$0.12**	**$0.14**	**$0.03**	**$0.89**	**$12.72**	**$2.54**	**$15.26**	**$16.15**
20-Year NPV	**$0.51**	**$0.10**	**$0.12**	**$0.02**	**$0.75**	**$5.71**	**$1.14**	**$6.85**	**$7.60**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.6 VVO ENABLEMENT

(i) VVO Enablement



a. Description

As described in Section B.3.i. - VVO, VVO enabled by AMI will provide real-time data on voltage, current, and power usage across the grid resulting in energy savings. This granular data allows the Company to dynamically adjust voltage levels, which improves energy efficiency and reduces losses. Additionally, AMI supports better demand response strategies and more precise fault detection and localization. To enable these capabilities, the Company will need to implement software and line devices such as voltage regulators, capacitors, and load tap controllers ("LTC") at substations. As described in Section B.4.i. – Asset Optimization, line sensors required for effective VVO are eliminated as the AMI network can provide the requisite voltage data back to the Company. Additional system enhancements include VVO/SCADA integration with the AMI headend and load management equipment to take advantage of the AMI voltage insights down to the feeder to complement existing conservation voltage reduction and optimization designs.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

Starting in Year 5 and overlapping with the last half of AMI meter deployment, VVO will require integration with the Company's Distribution Management System ("DMS"), as well as installation of

hardware in the field and at substations to deliver the expected benefits. Due to VVO's dependency on AMI data to track near- real-time voltage and avoid installation of additional sensors, the VVO deployment is expected to trail AMI deployment geographically on circuits where the technology has been prioritized.

The two-year VVO system integration requires upfront software, internal and external integration labor, and ongoing maintenance costs. Over six years and starting at the same time as the two-year integration in Year 5, regulators and capacitors will be installed on 65% of all feeders, yielding 1,078 regulators and 1,078 capacitors, while LTC upgrades will occur at 65% of all substation transformers. The all-in cost to design, procure, and install each of the equipment types is informed by the Company's Massachusetts VVO deployment. 100% of the VVO devices will require a cellular connection to communicate, which is calculated in Section D.2.i. - Communications Upgrades. Ongoing internal field labor will be required to troubleshoot and resolve field equipment issues at substation and distribution lines, and grid management internal labor will be required to manage the optimization function in the DMS and perform M&V activities.

Capital Cost Calculations:

VVO - Headend Integration Internal Labor Cost Calculations:						
Headend to VVO Integration - Internal Labor ($)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)
$700,000		2%		94%		10%

VVO - Headend Integration External Labor Cost Calculations:				
Headend to VVO Integration - External Labor ($)	X	Inflation (%)	X	Contingency (%)
$1,400,000		2%		10%

VVO - Upfront Headend Integration Software Cost Calculations:				
Headend to VVO Integration - Upfront Software ($)	X	Inflation (%)	X	Contingency (%)
$470,000		2%		10%

VVO - Upfront Transformer LTC All-In Cost								
Transformer LTC All-in Cost ($)	X	Total Number of Transformers (#)	X	Percentage of Transformers Need LTC (%)	X	Inflation (%)	X	Contingency (%)
$190,000		349		65%		2%		10%

VVO - Upfront Regulator and Capacitor Materials All-in Calculations:										
Capacitors (#)	X	Capacitor All-in Costs ($)	+	Regulators (#)	X	Regulator All-in Costs ($)	X	Inflation (%)	X	Contingency (%)
1,078		$68,000		1,078		$93,636		2%		10%

O&M Cost Calculations:

VVO - Ongoing Headend Integration Software Cost Calculations:							
Headend to VVO Integration - Upfront Software ($)	X	Ongoing Software O&M (%)	X	Inflation (%)	X	Contingency (%)	
$470,000		20%		2%		10%	

VVO - Grid Management Internal Labor Cost Calculations:									
Grid Management Labor (#)	X	Field Labor Rate ($)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)	
1		$182,000		2%		94%		10%	

VVO - Ongoing Field Labor Cost Calculations:													
Total Number of Transformers (#)	X	Percentage of Transformers with LTC (%)	X	Ongoing Internal FTE Labor Hours per Year per Transformer (Hours)	/	Working Hours in Year (Hours)	X	Field Labor Rate ($)	X	Inflation (%)	X	Labor Overhead (%)	X	Contingency (%)
349		65%		100		2,080		$182,000		2%		94%		10%

VVO Enablement List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Transformer LTC Controller All-in Cost ($)	$190,000	Company cost data from Massachusetts VVO and repurposed as estimates for Connecticut	Current cost estimates could increase faster than inflation and the timeline for material implementation could extend past 6 years
Total Number of Transformers (#)	349	Company estimate	The number of transformers that must be enabled for VVO may be higher or lower than this estimate
Percentage of Transformers With LTC (%)	65%	Company estimate based on Massachusetts data coupled with Connecticut service area dynamics	More or less feeders than 65% could need VVO capabilities
Capacitors (#)	1,078	Company estimate; Assumes 65% of all feeders will be enabled with VVO	The number of capacitors that must be enabled for VVO may be higher or lower than this estimate
Regulators (#)	1,078	Company estimate; Assumes 65% of all feeders will be enabled with VVO	The number of regulators that must be enabled for VVO may be higher or lower than this estimate

VVO Enablement List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Capacitor All-in Costs ($)	$68,000	Company cost data from Massachusetts VVO and repurposed as estimates for Connecticut	Current cost estimates could increase faster than inflation and the timeline for material implementation could extend past 6 years
Regulator All-in Costs ($)	$93,500	Company cost data from Massachusetts VVO and repurposed as estimates for Connecticut	Current cost estimates could increase faster than inflation and the timeline for material implementation could extend past 6 years
Grid Management Labor (#)	1	Company estimate; assumes 1 per state	The number of labor may be more than one FTE
Field Labor Rate ($)	$182,000	Company cost data	Labor costs may increase a rate faster than 2% inflation
Ongoing Internal FTE Labor Hours per Year per Transformer (Hours)	100	Company estimate	The number of hours per FTE per year per transformer could be greater or less than this estimate
Headend to VVO Integration - External Labor ($)	$1,400,000	Company estimate, assumes 2-year implementation	Current cost estimates could increase faster than inflation and the timeline for software implementation could extend past 2 years
Headend to VVO Integration - Internal Labor ($)	$700,000	Company estimate, assumes 2-year implementation	
Headend to VVO Integration - Upfront Software ($)	$470,000	Company estimate, assumes 2-year implementation	
Ongoing Software O&M (%)	20%	Company estimate	Ongoing software costs could be higher or lower than 20% of the upfront software cost
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%

c. Annual Cost Calculation and Cost Granularity

	Capital							
	Internal Labor	External Labor	Materials	Software	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 4	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 5	$0.26	$0.52	$39.97	$0.26	$0.24	$4.10	$2.82	**$48.16**
Year 6	$0.26	$0.53	$40.77	$0.26	$0.25	$4.18	$2.87	**$49.12**
Year 7	$0.00	$0.00	$41.58	$0.00	$0.00	$4.16	$2.84	**$48.58**
Year 8	$0.00	$0.00	$42.41	$0.00	$0.00	$4.24	$2.90	**$49.55**
Year 9	$0.00	$0.00	$43.26	$0.00	$0.00	$4.33	$2.96	**$50.54**
Year 10	$0.00	$0.00	$44.13	$0.00	$0.00	$4.41	$3.01	**$51.55**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$0.52**	**$1.04**	**$252.12**	**$0.52**	**$0.49**	**$25.42**	**$17.40**	**$297.51**
20-Year NPV	**$0.36**	**$0.72**	**$152.21**	**$0.36**	**$0.34**	**$15.36**	**$10.52**	**$179.86**

	O&M				Total
	Internal Labor	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 3	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 4	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 5	$0.62	$0.39	$0.06	$1.07	**$49.23**
Year 6	$1.06	$0.80	$0.11	$1.96	**$51.08**
Year 7	$1.46	$1.17	$0.15	$2.78	**$51.36**
Year 8	$1.87	$1.56	$0.19	$3.62	**$53.17**
Year 9	$2.31	$1.96	$0.23	$4.50	**$55.04**
Year 10	$2.76	$2.38	$0.28	$5.41	**$56.97**
Year 11	$2.81	$2.43	$0.28	$5.52	**$5.52**

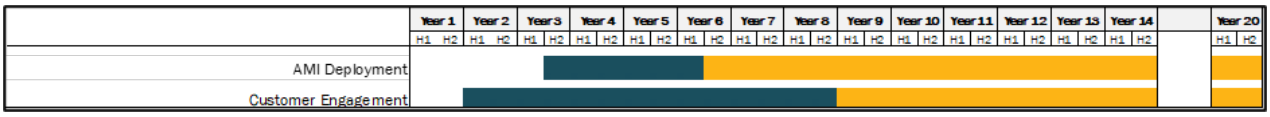
	O&M				Total
	Internal Labor	Corporate Overhead	Contingency	O&M Total	
Year 12	$2.87	$2.48	$0.29	$5.63	**$5.63**
Year 13	$2.92	$2.53	$0.29	$5.75	**$5.75**
Year 14	$2.98	$2.58	$0.30	$5.86	**$5.86**
Year 15	$3.04	$2.63	$0.30	$5.98	**$5.98**
Year 16	$3.10	$2.68	$0.31	$6.10	**$6.10**
Year 17	$3.17	$2.74	$0.32	$6.22	**$6.22**
Year 18	$3.23	$2.79	$0.32	$6.34	**$6.34**
Year 19	$3.29	$2.85	$0.33	$6.47	**$6.47**
Year 20	$3.36	$2.90	$0.34	$6.60	**$6.60**
20-Year Total	**$40.85**	**$34.88**	**$4.08**	**$79.81**	$377.32
20-Year NPV	**$16.67**	**$14.13**	**$1.67**	**$32.46**	$212.32

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.7 CUSTOMER

(i) Customer Engagement



a. Description

Customer engagement involves educating and informing customers on the benefits of AMI before, during, and after AMI deployment. Methods include:

(1) digital channels such as emails, Digital Customer Update e-newsletters, website content, social media (non-paid), and videos;

(2) print communications such as bill inserts, post cards, direct mail, and/or door hangers;

(3) customer-specific notifications by mail or email 90-/60-/30-day and by email or text message 1-3-days prior to an AMI meter exchange;

(4) events such as webinars and town halls,

(5) paid advertising, such as out-of-home, social media and digital campaigns, and

(6) Customer research through the Eversource Advisory Group (ESAG) and online community.

Engagement will begin in the months prior to the first meter installation and extend beyond AMI deployment to continuously inform and engage customers in how to take advantage of new usage insights and alerts as features and options become available.

The company will also launch a customer engagement and education campaign on the benefits of new TOU/TVR rates in advance of the TVR rollout plan, which is expected to commence at the end of AMI meter deployment. One of the primary objectives of the TOU/TVR customer engagement plan is to maximize the number of customers opting into TOU/TVR rate structures. The initiative will involve the above-mentioned channels to consistently educate customers on changes coming, what to expect as their meters are swapped out, how to get the most out of their new meter and how to enroll in new rates that will help them save on their electric bill.

A detailed implementation plan describing the Company's specific strategy related to Customer Engagement will be submitted with the full AMI implementation plan.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The customer engagement plan identifies proactive customer outreach across multiple channels and at key stages during and after the AMI meter deployment. The costs were estimated based on current internal cost estimates for collateral material and delivery to reach customers effectively to achieve objectives.

O&M Cost Calculations:

Customer Engagement – Internal Labor Costs Calculation:												
Deployment – FTEs (#)	X	Cost per FTE ($/FTE)	X	Deployment Duration (yr)	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)		
1		$205,000		3								
Energy Insight and Ways to Save - FTEs (#)	X	Cost per FTE ($/FTE)	X	Energy Insight and Ways to Save – Duration (yr)		2%		10%		94%		
1		$205,000		1								
TOU/TVR – FTEs (#)	X	Cost per FTE ($/FTE)	X	TOU/TVR - Duration (yr)								
1		$205,000		4								

Customer Engagement - Outreach Material, In-Person and Digital Events and Ad Campaigns Costs Calculation:						
Early Awareness - Outreach Material, In-Person & Digital Events and Ad Campaigns ($)	X	Early Awareness - Duration (yr)				
$611,980		1				
Deployment - Outreach Material, In-Person & Digital Events and Ad Campaigns ($)	X	Deployment Duration (yr)	X	Inflation (%)	X	Contingency (%)
$2,317,318		3				
Energy Insight and Ways to Save - Outreach Material, In-Person and Digital Events and Ad Campaigns ($)	X	Energy Insight and Ways to Save - Duration (yr)		2%		10%
$2,171,460		1				
TOU/TVR - Outreach Material, In-Person and Digital Events and Ad Campaigns ($)	X	TOU/TVR - Duration (yr)				
$1,363,361		4				

Customer Engagement List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Cost per FTE ($/FTE)	$205,000	Company cost data	Labor costs may increase at a rate faster than 2% inflation
Early Awareness - Outreach Material, In-Person & Digital Events and Ad Campaigns ($)	$611,980	Company cost data	Occurs 1 year before deployment begins. Costs may increase faster than 2% inflation
Early Awareness - Duration (year)	1	Company estimate	Occurs 1 year before deployment begins. The number of events and campaigns could require internal labor
Deployment - FTEs (#)	1	Company estimate	Occurs during 3-year deployment. Deployment could extend longer and could impact the number of FTEs needed. The number of events and campaigns could require more than 1 FTE
Deployment Duration (year)	3	Company estimate	
Deployment - Outreach Material, In-Person & Digital Events and Ad Campaigns ($)	$2,317,318	Company cost data	Occurs 3 years during deployment. Associated costs (postage, hangers, events, videos, etc.) may increase faster than 2% inflation
Energy Insight and Ways to Save - FTEs (#)	1	Occurs last year of deployment	Occurs for 1 year during deployment. Deployment could extend long and impact the number of FTEs needed. The number of events and campaigns could require more than 1 FTE
Energy Insight and Ways to Save - Duration (yr)	1	Company estimate	
Energy Insight and Ways to Save - Outreach Material, In-Person and Digital Events and Ad Campaigns ($)	$2,171,460	Company cost data	Occurs for 1 year during deployment. Associated costs (postage, hangers, events, videos, etc.) may increase faster than 2% inflation
Post Deployment (TOU/TVR) - FTEs (#)	1	Company estimate	Starts when TOU/TVR is enabled in Year 5 and continues for four years through Year 8. Deployment could extend longer and could impact the number of FTEs. The number of events and campaigns could require more than 1 FTE
Post Deployment (TOU/TVR) - Duration (yr)	4	Company estimate	

Post-Deployment (TOU/TVR) – Outreach Material, In-Person and Digital Events and Ad Campaigns ($)	$1,363,361	Company cost data	Starts when TOU/TVR is enabled in Year 5 and continues for four years through Year 8. Associated costs (e.g., postage, hangers, events, videos, etc.) may increase faster than 2% inflation
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

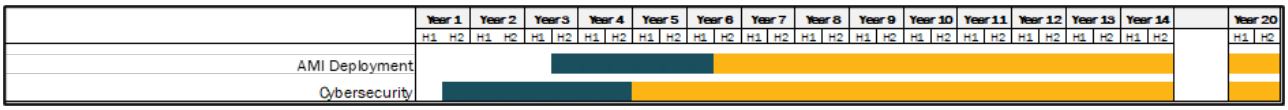
	Capital	O&M					Total
	Total Capital	Internal Labor	Materials	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 2	$0.00	$0.21	$0.64	$0.20	$0.08	$1.14	**$1.14**
Year 3	$0.00	$0.22	$2.46	$0.20	$0.27	$3.15	**$3.15**
Year 4	$0.00	$0.22	$2.51	$0.21	$0.27	$3.21	**$3.21**
Year 5	$0.00	$0.45	$4.06	$0.43	$0.45	$5.39	**$5.39**
Year 6	$0.00	$0.46	$3.98	$0.43	$0.44	$5.32	**$5.32**
Year 7	$0.00	$0.24	$1.57	$0.22	$0.18	$2.20	**$2.20**
Year 8	$0.00	$0.24	$1.60	$0.23	$0.18	$2.25	**$2.25**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$0.00**	**$2.04**	**$16.81**	**$1.92**	**$1.89**	**$22.66**	**$22.66**
20-Year NPV	**$0.00**	**$1.45**	**$11.93**	**$1.36**	**$1.34**	**$16.08**	**$16.08**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

D.8 DATA

(i) Cybersecurity



a. Description

Deploying AMI meters and the associated network and systems to connect these devices and collect, analyze, and store the data will require adding multiple layers of security to ensure that customer data is secure. Measures to enhance confidentiality, integrity, and availability ("CIA") of data across all systems are also components of the scope of this effort. Additional cyber protection measures will also be implemented as the Company develops additional customer-oriented analytics use cases. These measures will follow the security design principles and cybersecurity capabilities identified in the Joint Cybersecurity and Privacy Framework supported by PURA.

The AMI network is a purpose-built, private infrastructure isolated from the public internet. Meters communicate exclusively over Eversource-controlled channels to designated head-end systems, no open internet ports and no lateral pathways into corporate IT without crossing enforced segmentation boundaries. Device types, protocols, and endpoint identities are allowlisted, making anomalous traffic immediately detectable against a well-understood baseline.

Security across the integrated AMI ecosystem is maintained through a sustained, lifecycle program:

- **Vulnerability management**: Regular scanning and patching across AMI components ensure known vulnerabilities are identified and remediated in a timely manner. Firmware updates to field devices are authenticated and integrity-verified to prevent tampering.
- **Security architecture reviews**: New integrations and system changes undergo a formal security review before deployment to ensure risks are identified and addressed before new data paths are introduced.
- **Access control**: Administrative access is governed by the principle of least privilege, multi-factor authentication, and privileged access management controls. Standing access is minimized, and privileged sessions are monitored and logged.
- **Continuous monitoring**: Network traffic and system activity are monitored for anomalous behavior, with alerts triaged through established security operations workflows.

- **Incident response readiness**: AMI-specific threat scenarios are incorporated into tabletop exercises and response playbooks to ensure the team can respond effectively when incidents occur.
- **Periodic assessments**: Regular security assessments and penetration testing are conducted on a defined schedule. Findings are risk-rated and tracked through to remediation.

All vendors with AMI access must complete a DDQ/ through our vendor management program and be documented in Archer GRC before engagement. Technically, vendor access is constrained to defined integration boundaries through access controls and network segmentation. Contracts require alignment with NIST SP 800-171. Where a vendor falls short of minimum requirements, a formal exception with CISO approval is required before engagement proceeds.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

With the prevalence of granular usage customer data and added access points on the AMI network, it is critical that the Company enhance system and network security through the existing "defense in depth" strategy adding security layers. These enhancements include end-to-end encryptions for all new use cases, data paths, and system integrations with associated ongoing maintenance. The estimated costs include upfront and ongoing labor to provide ongoing support across security architecture management, security architecture, application security, and security engineering, ongoing annual fees for hardware, software, services, and licensing, and physical security enhancements to protect critical infrastructure. These costs were estimated with particular attention to resources needed to be engaged in requirements gathering, vendor selection, and implementation while managing associated firewalls, penetration testing, and new hardware/software for key management.

Capital Cost Calculations:

Cybersecurity - Physical Security Cost Calculation:				
Physical Security ($)	X	Contingency (%)	X	Inflation (%)
$1,000,000		10%		2%

Cybersecurity - Upfront Internal Labor Cost Calculation:										
Upfront Labor (#)	X	Cost per Cybersecurity FTE ($ per FTE)	X	Years	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
12		$175,000		2		2%		10%		94%

O&M Cost Calculations:

Cybersecurity - Ongoing Internal Support Cost Calculation:										
Ongoing Labor Support (#)	X	Cost per Cybersecurity FTE ($ per FTE)	X	Years	X	Inflation (%)	X	Contingency (%)	X	Labor Overhead (%)
3		$175,000		18		2%		10%		94%

Cybersecurity - Ongoing Licensing and Fees Cost Calculation:				
Ongoing Licensing and Fees	X	Contingency (%)	X	Inflation (%)
$2,205,000		10%		2%

Cybersecurity List of Assumptions			
Assumption Description	Assumption Value	Assumption Justification	Assumption Uncertainties
Physical Security ($)	$1,000,000	Company estimate	One-time, over first two years of AMI deployment. The amount of physical security and timeline could be longer impact cost
Upfront Labor (#)	12	Company estimate	Cost spread over two years before AMI deployment begins to support implementations of all new systems and integrations. The number of FTEs required could be higher or lower than this estimate
Ongoing Labor Support (#)	3	Company estimate	The number of FTEs required could be higher or lower than this estimate
Cost per Cybersecurity FTE ($ per FTE)	$175,000	Company cost data	Labor costs may increase a rate faster than 2% inflation
Ongoing Licensing and Fees	$2,205,000	Company estimate	Ongoing costs to support all new systems and integrations may be higher or lower than this estimate
Contingency (%)	10%	Company cost data	Actual upfront and ongoing contingency may be higher or lower than 10%
Labor Overhead (%)	94%	Company cost data	Actual future company overheads may be higher or lower than this value
Inflation (%)	2%	PURA requirement	Inflation may rise higher or lower than 2%. In recent years, inflation has risen higher than 2% annually

c. Annual Cost Calculation and Cost Granularity

	Capital					
	Internal Labor	External Labor	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 1	$0.54	$0.00	$0.50	$0.05	$0.07	**$1.16**

	Capital					
	Internal Labor	External Labor	Corporate Overhead	Contingency	AFUDC	Total Capital
Year 2	$1.09	$0.00	$1.02	$0.11	$0.14	**$2.36**
Year 3	$0.56	$0.53	$0.52	$0.11	$0.07	**$1.79**
Year 4	$0.00	$0.54	$0.00	$0.05	$0.00	**$0.60**
Year 5	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 6	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 7	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 8	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 9	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 10	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 11	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 12	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 13	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 14	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 15	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 16	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 17	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 18	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 19	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
Year 20	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
20-Year Total	**$2.19**	**$1.07**	**$2.05**	**$0.33**	**$0.28**	$5.92
20-Year NPV	**$1.91**	**$0.85**	**$1.79**	**$0.28**	**$0.25**	$5.07

	O&M					Total
	Internal Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 1	$0.00	$0.00	$0.00	$0.00	$0.00	**$1.16**
Year 2	$0.55	$2.29	$0.51	$0.28	$3.64	**$6.00**
Year 3	$0.56	$2.34	$0.52	$0.29	$3.71	**$5.50**
Year 4	$0.57	$2.39	$0.53	$0.30	$3.78	**$4.38**
Year 5	$0.58	$2.43	$0.54	$0.30	$3.86	**$3.86**
Year 6	$0.59	$2.48	$0.55	$0.31	$3.94	**$3.94**
Year 7	$0.60	$2.53	$0.57	$0.31	$4.02	**$4.02**
Year 8	$0.62	$2.58	$0.58	$0.32	$4.10	**$4.10**
Year 9	$0.63	$2.64	$0.59	$0.33	$4.18	**$4.18**
Year 10	$0.64	$2.69	$0.60	$0.33	$4.26	**$4.26**
Year 11	$0.65	$2.74	$0.61	$0.34	$4.35	**$4.35**

	O&M					Total
	Internal Labor	Software Licensing / Fees	Corporate Overhead	Contingency	O&M Total	
Year 12	$0.67	$2.80	$0.62	$0.35	$4.43	**$4.43**
Year 13	$0.68	$2.85	$0.64	$0.35	$4.52	**$4.52**
Year 14	$0.69	$2.91	$0.65	$0.36	$4.61	**$4.61**
Year 15	$0.71	$2.97	$0.66	$0.37	$4.70	**$4.70**
Year 16	$0.72	$3.03	$0.68	$0.37	$4.80	**$4.80**
Year 17	$0.74	$3.09	$0.69	$0.38	$4.89	**$4.89**
Year 18	$0.75	$3.15	$0.70	$0.39	$4.99	**$4.99**
Year 19	$0.76	$3.21	$0.72	$0.40	$5.09	**$5.09**
Year 20	$0.78	$3.28	$0.73	$0.41	$5.19	**$5.19**
20-Year Total	**$12.48**	**$52.40**	**$11.70**	**$6.49**	**$83.06**	**$88.98**
20-Year NPV	**$6.10**	**$25.61**	**$5.72**	**$3.17**	**$40.59**	**$45.66**

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

(ii) Data Storage and Processing

a. Description

The AMI implementation introduces costs associated with data storage and processing that do not currently exist. Because AMI meters are capturing usage and other information multiple times an hour, AMI systems generate vast quantities of high-resolution data necessitating robust and scalable storage solutions. Eversource must invest in advanced data storage infrastructure capable of handling terabytes to petabytes of data, all the while ensuring that this information is securely stored and easily accessible. Additionally, the processing power required to analyze and utilize this data for enhancing business functions—such as load forecasting, demand response, and customer billing—demands substantial investment in high-performance, computer resources and sophisticated data analytics platforms. The infrastructure and processing capabilities are critical to leveraging the full potential of AMI data, enabling utilities to drive operational efficiencies, improve customer service, and support advanced energy management strategies. Therefore, the initial and ongoing costs of maintaining such a comprehensive data management system represent a financial commitment that is included in Section D.5.ii – Customer Experience Portal, D.5.iii. - Engineering and Customer Usage Analytics, and Section D.5.iv - Green Button Connect.

Please see Section IX Appendix for a list of All Benefits that are dependent on this cost or investment category.

b. Cost Calculation Methodology

The capital and O&M cost assumptions and methodology needed for Data Processing and Storage are included in Section D.5.ii – Customer Experience Portal, D.5.iii. - Engineering and Customer Usage Analytics, and Section D.5.iv - Green Button Connect.

c. Annual Cost Calculation and Cost Granularity

The capital and O&M costs needed for Data Processing and Storage are included in Section D.5.ii – Customer Experience Portal, D.5.iii. - Engineering and Customer Usage Analytics, and Section D.5.iv - Green Button Connect.

d. Methodology to Track Actual Costs

The Company will track ongoing costs and identify any new or unplanned costs to PURA via reporting requirements established in the PURA ruling. Cost data will be provided in the tracker format approved by PURA on September 19, 2024.

IV. SUPPLEMENTAL BCA WITHOUT CARBON BENEFITS

PURA has requested that the Company provide a supplemental BCA Report without the inclusion of Carbon Reduction benefits to understand the magnitude of other benefits derived from AMI deployment.

As shown in Section A.4 – Summary of Results, Carbon Reduction benefits represent $441.3 million nominal and $176.8 million NPV in benefits over the 20-year plan. These benefits become available in the second half of 2027, when the Company anticipates avoidance of non-technical line losses as a result of AMI meter deployment. However, the bulk of this benefit begins realization once VVO is enabled in Year 3. For more details on the drivers of carbon reduction and the calculation of these benefits, please see Sections B.3.i. – VVO, B.3.ii. – Carbon Avoidance, and B.7.i. – Reduced Theft and Non-Technical Line Losses. As shown in Figure 14 below, the 20-year nominal BCR without Carbon Reductions is 0.88, while on a present value basis is 0.66. This indicates a BCR reduction of 0.17 nominal and 0.11 NPV compared with including carbon benefits.

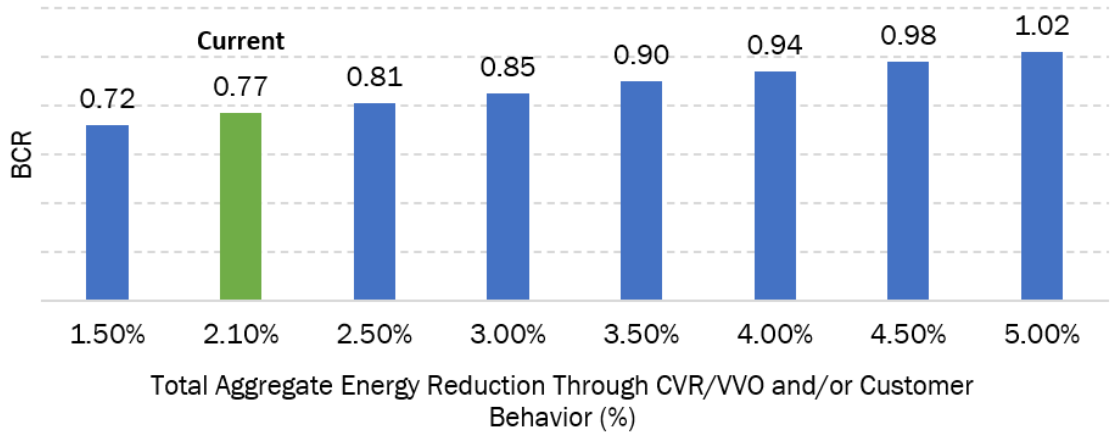
Figure 14 - Detailed Financial Summary By Cost and Benefit – Excluding Carbon Reduction Benefits

Total 20-Year Cost and Benefit	Nominal Value ($M)	NPV Value ($M)
Total AMI Cost	**$2,568.7**	**$1,557.3**
Meters	$340.0	$238.3
Undepreciated Meter Balance	$136.7	$66.2
Communications Upgrades	$302.2	$167.4
Meter Data Management System (MDMS)	$174.8	$105.1
Customer Information System (CIS)	$536.8	$354.1
Organizational Readiness	$104.5	$83.4
Contact Center	$141.3	$77.2
Incremental Labor (Included in each Cost category)	$0.0	$0.0
Outage Management System (OMS) Integration	$14.8	$11.6
Customer Experience Portal	$116.0	$66.0
VVO Enablement	$377.3	$212.3
Engineering and Customer Usage Analytics	$84.9	$46.4
Customer Engagement	$22.7	$16.1
Cybersecurity	$89.0	$45.7
Revenue Assurance (Non-Technical Line Loss)	$45.7	$20.4
Green Button Connect	$16.2	$7.6
Data Storage and Processing	$0.0	$0.0
Load Settlement	$65.8	$39.4
Total AMI Benefit	**$2,272.4**	**$1,028.6**
Meter Reading	$50.8	$21.2
Avoided Meter Capital	$343.9	$160.3
Remote Account Connect/Disconnect	$77.5	$32.2
No Trouble Found Calls Reduction	$13.0	$5.7
System Costs Avoidance	$393.8	$199.5
Volt/VAR Optimization (VVO)	$409.0	$163.8
Carbon Reduction	$0.0	$0.0
Asset Optimization	$169.2	$96.4
Advanced Engineering Analysis	$88.5	$38.7
Avoided Connectivity Survey	$16.8	$6.7
Improved Restoration Significant Storms	$363.2	$162.4
Improved Restoration - Blue Sky	$5.7	$2.5
Reduced Bad Debt	$188.7	$74.5
Reduced Theft and Non-Technical Line Loss	$39.6	$16.5
Time of Use /Time Varying Rates	$57.1	$24.3
Time of Use /Time Varying Rates	$55.4	$23.9
Customer Targeting for Incentives	$0.0	$0.0

Total 20-Year Cost and Benefit	Nominal Value ($M)	NPV Value ($M)
Improved Reliability	$0.0	$0.0
Billing Accuracy and Timeliness	$0.0	$0.0
Net Benefit ($M)	-$296.3	-$528.7
Benefit-Cost Ratio	0.88	0.66

V. SENSITIVITY ANALYSIS

This BCA is based on numerous assumptions for many variables affected by system conditions and customer behavior. The Company has endeavored to adopt what it believes to be the most probable value for each variable, but also recognizes that there may be a wide range of potential outcomes for some variables. One of the more difficult variables to predict is customer response to the availability of usage data, insights, and alerts, and the significantly greater control that customers will enjoy as a result of AMI. In the base model, no increase in energy efficiency related to customer behavior is assumed; rather, the only energy reduction is attributed to CVR/VVO. Nonetheless, the Company intends to actively engage customers with insights, alerts and recommendations arising from their usage data with the goal of promoting greater conservation and efficiency. As the sensitivity table below illustrates, if the aggregate energy reduction from AMI reaches 5%, a BCR greater than 1.0 is achieved.

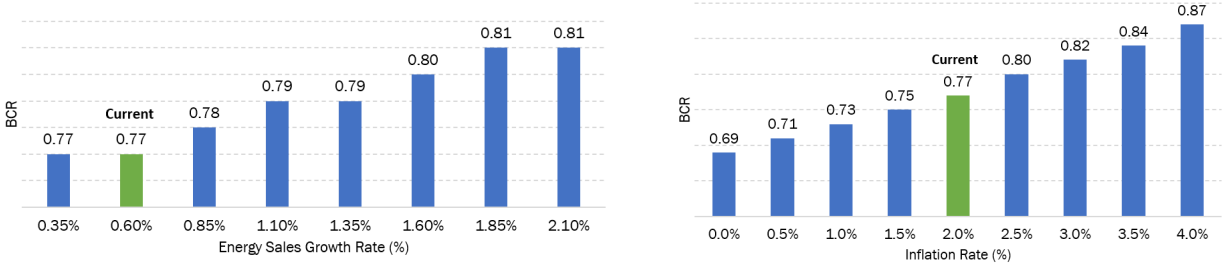


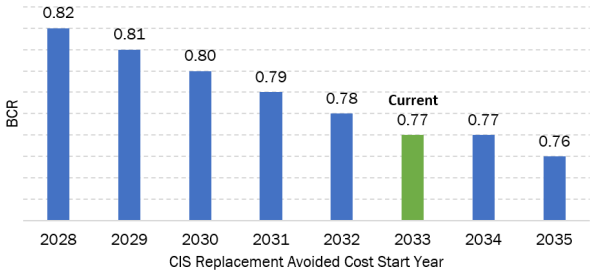
Several other data inputs and assumptions have an outsized impact on the final BCR. These data inputs include the energy sales growth, inflation rate, the number of significant storms per year, value of carbon avoidance, the year when the CIS replacement avoided cost benefit begins, and TOU/TVR participation rate. As shown in the charts as part of Figure 15, minor changes to each input can drive the BCR higher or lower. In each chart, the current base case assumption produces a BCR

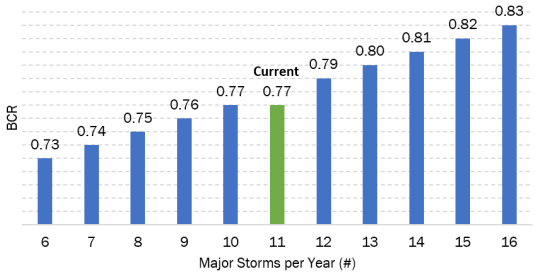
of 0.77, and alternative values illustrate how the BCR could move if the underlying assumption is updated.

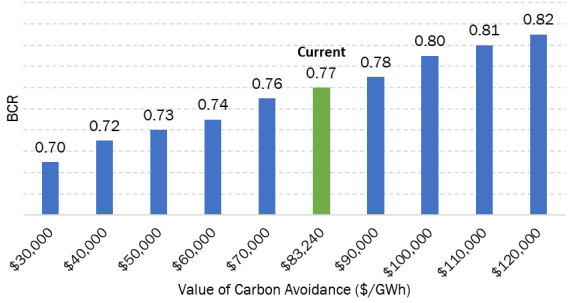
- **Energy sales growth rate**: If energy sales were to increase from 0.6% to 2.1%, it would increase the BCR from 0.77 to 0.81 as energy sales drives several benefits, most notably VVO, TOU/TVR, and Carbon Reduction.
- **Inflation Rate**: Inflation affects the avoided costs and benefit streams over time. If inflation were updated from 2.0% required by PURA to 4.0%, the BCR would increase to 0.87.
- **CIS Replacement Avoided Cost Start Year**: The start date for CIS replacement avoided costs directly affects when those savings begin to accrue; realizing the benefit sooner increases the present value of avoided costs and improves the BCR. The base case assumes the legacy CIS is decommissioned in 2033, which is intentionally conservative to allow for additional time to retire the system. If the avoided cost start year shifts from 2033 to 2029—aligned to the expected go-live of the new CIS under the AMI program—the BCR increases to 0.81. Conversely, any delay in decommissioning the legacy CIS would push savings further out and reduce the BCR.
- **Number of major storms per year:** Outage management and resilience-related benefits increase with storm frequency. If storms per year were updated from 11 to 16, the BCR increases to 0.83.
- **Value of carbon avoidance:** The unit value of avoided emissions is uncertain and carbon benefits are a meaningful component of total benefits. If the carbon value were updated from $80k/GWh to $120k/GWh, the BCR increases to 0.82.
- **TOU/TVR participation rate:** The BCA assumes 6% residential participation based on the Company's internal program experience. This is conservative relative to EIA 2023 utility self-reported data showing 14% enrollment among residential customers with AMI across 356 utilities offering time-varying rates. If participation increased closer to the national average, the BCR would increase to 0.79.

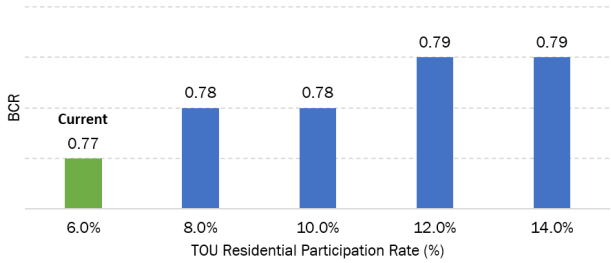
Figure 15 – Sensitivity Analysis of Key Data Inputs and Assumptions











VI. COMPETITIVE SOLICITATIONS

As soon as the Massachusetts Department of Public Utilities approved the Company's proposed AMI Plan on November 30, 2022 for AMI implementation in Massachusetts, the Company began scoping and drafting requests for proposals ("RFPs) for the AMI Program, including: (1) the program management office ("PMO"), organizational change management ("OCM"), and System Integrator; (2) MDMS and Integrator; (3) AMI HES, Meters, and Network; (4) installation vendors; and (5) other technology vendors. The Company has completed all competitive solicitations and RFPs for the AMI Program.

The Company facilitated the RFP process through a structured and transparent approach designed to ensure fairness and competitiveness. The process included:

- **Initial Planning:** Identification of specific AMI requirements and use cases, as well as timing to select vendors to maintain program deployment schedule.
- **RFP Development**: Developed comprehensive RFP documentation that outlined technical specifications, performance criteria, and evaluation metrics.
- **Publication and Outreach**: Notified potential vendors through direct communications to participate in RFP process.
- **Evaluation and Selection**: Formed a cross-functional evaluation committee, consisting of representatives from various Company departments, for each RFP to assess bids based on predefined criteria including technical capability, cost, and vendor reliability. The committee developed a set of evaluation criteria to ensure a consistent and fair assessment of all bids.

Multiple factors were considered as part of the evaluation and scoring of all bidders. Criteria included but was not limited to:

- Assessment of the technical features and functionalities of the proposed solutions, including compliance with specified requirements and performance metrics.
- Evaluation of the total cost of proposed solutions, including initial procurement, installation, operational, and other ongoing costs.
- Analysis of the bidder's track record, ability to deliver on commitments, and other reliability standards.

Each bid was scored against the predefined criteria using a weighted scoring methodology. The scores were aggregated to provide an overall score for each bid. The Company conducted reference calls with other utilities that had implemented similar solutions from the bidder and scheduled interviews with the top three (3) bidders for each RFP. Based on the aggregated scores, reference calls, and interview outcomes, the evaluation committee selected the winning bids. The selected vendors demonstrated the best overall value, balancing technical capability, cost-effectiveness, and reliability.

- Contract Negotiation: Cross-functional evaluation committee and bidders engaged in contract negotiations to settle on pricing, terms and conditions, service level agreements, and other contractual requirements. The Company ensured that the full meter lifecycle costs were comprehensively accounted for in the RFP process, which included initial procurement costs associated with infrastructure, installation costs for labor and logistical expenses for meter deployment, operational costs for ongoing maintenance, software updates, software-as-a-service (SaaS) fees, and data management expenses, as well as end-of-life costs for eventual meter replacement and disposal costs.

Through this rigorous process, all program technology vendors and partners were selected, along with materials vendors for meters and field network equipment. To help reduce costs for Connecticut customers, Eversource leveraged economies of scale in the course of issuing the competitive RFPs, asking vendors to provide quotes for both Massachusetts and Connecticut AMI deployment. Within the contracts for some of these selected vendors, the AMI Program was able to negotiate competitive pricing and favorable terms for expanding and scaling services across the Company's service territories, if approved in accordance with each state's AMI Plan. For example, the Company was able to agree to very favorable terms with the electric meter manufacturer to provide competitive pricing for bridge meter returns and price per meter under the assumption that the Company would have combined state quantities for Massachusetts and Connecticut. There will also be cost savings to Connecticut customers by leveraging the expertise of the current AMI project personnel in these selected technologies.

The Company selected the following key program partners to meet program objectives:

1) Itron was selected as the Company's AMI solution vendor for the HES, electric meters, and network communications equipment.

2) Siemens was selected as the MDMS provider.
3) TRC was selected as the system integrator for the MDMS.
4) SAP was selected as the Company's Customer Information System ("CIS") provider.
5) Ernst and Young ("EY") was selected as the Company's CIS integrator.
6) Accenture was selected as the overall AMI System Integrator responsible for blueprinting/requirements, high-level designs, solution architecture, test management, test data, test environment management, release management, System Integration Testing ("SIT") execution, and cutover and hyper-care support. Accenture was also selected to oversee Metering Edge System Integrations and Enterprise Data Platform ("EDP") development and system integration.
7) Oracle / Opower was selected as the Customer Web Portal and Solution Provider.
8) Elecnor Hawkeye was selected as the Communications Installation Vendor ("CIV").
9) Grid One Solutions was selected as the Meter Installation Vendor ("MIV).
10) Utility API was selected as the Green Button Connect Solution Provider.
11) West Monroe was selected to manage the PMO, which oversees the management and governance of Financial Reporting, Program Reporting, Resource Management, Schedule Management, Risks/Issue Management, Scope Management, Vendor Management, and Quality Management. West Monroe was also selected to develop and implement OCM.
12) Z2 Solutions was selected as AMI Program Advisors who supported the development of RFPs and evaluation of vendor services.

Eversource also works with a number of partners, such as Utilipros, Powersolve, TCS, and Gridbright, on various support applications (e.g., asset management) which will need to be updated or modified in order to enable end-to-end AMI functionality.

The selected vendors noted above are engaged and support enablement for the following use cases that are considered part of the Company's AMI Program:

1. Asset Lifecycle
    a. Add Service Delivery Point
    b. New AMI Meter
    c. New Network Device
    d. Receive AMI Meter
    e. Receive AMI Network Device
    f. Install AMI Electric Meter
    g. Remove AMI Electric Meter
    h. Replace AMI Electric Meter
    i. Install AMI Network Device
    j. Network Device Maintenance
2. Mass Deployment Management
    a. Meter Installation Vendor Planning and Sync
    b. Meter Installation Vendor Route Release and Sync
    c. Exchange Legacy Meter for AMI

   d. Return to Utility
   e. AMI Provisioning
   f. Meter Exchange Exception Handling
   g. Customer Notification
3. Meter Data Collection & Process
   a. AMI Meter Reads
4. Billing
   a. Cycle Billing
   b. Cycling Billing (No Read)
   c. Move-Out Billing (No Read)
   d. Cycle Billing after Meter Exchange (non-AMI to AMI)
   e. Cycle Billing after Meter Exchange (AMI to AMI)
   f. Move Out (Read Only)
   g. Move In (Read Only)
5. Events & Alarms
   a. AMI Events & Alarms
   b. Meter Replacement Alarm
   c. Investigate Alarm
   d. Emergency Alarm
6. Serve the Customer
   a. Customer Complaint
7. Remote Connect/Disconnect
   a. Move-Out Billing (with Remote Disconnect)
   b. Move-In Disconnect Cancel
   c. Move-Out Billing (Disconnect Failure Exception)
   d. Move-In (With Remote Connect)
   e. Move-In Billing (Connect Failure Exception)
   f. Customer Requested Disconnect
   g. Customer Requested Connect
   h. Disconnect Cancel
   i. Move-In Reconnect
   j. Dunning Disconnect
   k. Connect after Payment
   l. Dunning Disconnect (without Remote Switch)
   m. Connect After Payment (without Remote Switch)
8. Outage Detection
   a. Verify Reported Power Outage
   b. Verify Reported Power Restoration
   c. Report Power Outage
   d. Report Power Restoration
9. Complex Billing

a. Time Varying Rates
b. Rate Change
c. Cycle Billing (season change of rate)
d. Totalized Meter Management
e. Coincident Demand Billing
f. MV-90 Reads

10. Other Operational Capabilities

a. AMI Meter Fails Provisioning
b. Unauthorized Usage or Authorized Connect
c. On-Demand Read
d. Power Status Check
e. Switch Status Check
f. Network Device Inspection
g. Electric Meter Inspection
h. Opt-Out Enroll and Move Out
i. Opt-Out Meter Replacement
j. Opt-Out Cycle Billing
k. Populate Data Lake
l. Customer Data Portal

VII. CUSTOMER OUTREACH AND ENGAGEMENT

The Company's AMI Plan discusses the Company's Customer Outreach and Engagement Framework.

VIII. PRE-PAY OPTION

Based on PURA's ruling, the Company is not including a pre-pay program in this Plan.

IX. APPENDIX

Figure 16 and 17 show the necessary infrastructure and O&M costs for each quantifiable and non-quantifiable benefit, respectively. Descriptions of each infrastructure and O&M cost category can be found in the table below.

Figure 16 - Necessary Infrastructure and O&M Costs for each Quantifiable Benefit

Benefits Section	3.D.1.i – Meters	3.D.1.ii – Undepreciated Meter Balance	3.D.2.i – Communications Upgrades	3.D.3.i – MDMS	3.D.3.ii – CIS	3.D.3.iii – Load Settlement	3.D.4.i – Organizational Readiness	3.D.4.ii – Contact Center	3.D.4.iii – Incremental Labor	3.D.4.iV – Revenue Assurance (Non-Technical Line Loss)	3.D.5.i – OMS Integration	3.D.5.ii – Customer Experience Portal	3.D.5.iii – Engineering and Customer Usage Analytics	3.D.5.iv – Green Button Connect	3.D.6.i – VVO Enablement	3.D.7.i – Customer Engagement	3.D.8.i – Cybersecurity	3.D.8.ii – Data Storage and Processing
3.B.1.i – Meter Reading	X	X	X	X	X		X	X	X							X	X	X
3.B.1.ii – Avoided Meter Capital	X		X	X			X											
3.B.2.i – Remote Account Connect/Disconnect	X	X	X				X	X	X	X						X	X	
3.B.2.ii – No Trouble Found Calls Reduction	X	X	X	X	X		X				X						X	X
3.B.3.i – Volt/Var Optimization (VVO)	X	X	X	X			X						X		X		X	X
3.B.3.ii – Carbon Reduction	X	X	X	X			X						X		X		X	X
3.B.4.i – Asset Optimization	X		X	X			X		X						X		X	X
3.B.4.ii – System Costs Avoidance			X		X		X	X	X								X	
3.B.5.i – Advanced Engineering Analysis	X	X	X	X			X		X				X				X	X
3.B.5.ii – Avoided Connectivity Survey	X	X	X	X			X		X		X				X		X	X
3.B.6.i – Improved Restoration Significant Storms	X	X	X	X			X		X		X						X	X
3.B.6.ii – Improved Restoration Blue Skies	X	X	X				X		X		X						X	X
3.B.7.i – Reduced Bad Debt	X	X	X		X		X	X	X								X	
3.B.7.ii – Reduced Theft & Non-Technical Line Loss	X	X	X		X		X		X	X		X	X				X	X
3.B.7.iii – Reduced Soft Close Loss	X	X	X		X		X		X	X			X				X	
3.B.8.i – Time of Use /Time Varying Rates	X	X	X	X		X	X	X	X			X	X				X	X

Figure 17 - Necessary Infrastructure and O&M Costs for each Non-Quantified Benefit

Non-Quantifiable Benefits Section	3.D.1.i – Meters	3.D.1.ii – Undepreciated Meter Balance	3.D.2.i – Communications Upgrades	3.D.3.i – MDMS	3.D.3.ii – CIS	3.D.5.i – OMS Integration	3.D.4.i – Organizational Readiness	3.D.4.ii – Contact Center	3.D.4.iii – Incremental Labor	3.D.7.i – Customer Engagement	3.D.5.iii – Engineering and Customer Usage Analytics	3.D.5.iv – Green Button Connect	3.D.5.ii – Customer Experience Portal	3.D.8.i – Cybersecurity	3.D.8.ii – Data Storage and Processing
3.C.1.i – Customer Satisfaction - Outage Restoration Notifications	X	X	X	X	X	X	X	X	X	X			X	X	X
3.C.2.i – Customer Empowerment and System Utilization - More Accurate Load Profiles	X	X	X	X			X		X		X			X	X
3.C.3.i – Operational and Customer Satisfaction - Validate Resilience and Reliability Measures	X	X	X	X		X	X		X					X	X
3.C.4.i – Operational - Integrating AMI Data with System Operations Center	X	X	X	X			X		X		X			X	
3.C.5.i – Safety - Public Safety and Downed Wires	X	X	X	X		X	X		X					X	X
3.C.6.i – Efficiency - Shared AMI Systems Across Affiliates			X	X	X		X		X					X	
3.C.7.i – Customer Engagement - Detailed Billing Data and Notifications	X	X	X	X	X		X	X	X	X		X	X	X	X
3.C.7.ii – Customer Engagement - Load Disaggregation	X	X	X	X			X	X	X	X			X	X	X

Necessary Infrastructure and O&M Costs	Necessary Infrastructure and O&M Description
Meters	AMI meters are sophisticated devices that not only measure energy consumption but also communicate this data back to the utility via a communications network. This capability enables a more responsive and efficient energy grid, allowing for all benefits listed throughout this Final Report. These meters are integral to the modernization of the energy grid, providing both utilities and customers with greater visibility and control over energy usage. Without installation of these AMI meters, the benefits from remote meter reading would not be possible.
Undepreciated Meter Balance	The removal of AMR and bridge meters that have not reached the end of their useful life and therefore have undepreciated balances remaining. Replacement of these undepreciated meters is vital to the AMI mesh network, thereby enabling the remote meter reading benefits to the Company's entire service territory.

Necessary Infrastructure and O&M Costs	Necessary Infrastructure and O&M Description
Communications Upgrades	AMI systems require robust, two-way communication networks to transmit data between the smart meters and the Company's back-office applications. Remote reading of AMI meters would not be possible without the communications upgrades necessary to get the meter data from the field back to the Company's systems.
MDMS	The MDMS is a critical back-office system that processes, stores, and manages the vast amounts of data collected from smart meters. The MDMS ensures data accuracy, supports real-time data analytics, and integrates with other Company systems to provide valuable insights for billing, customer service, and grid management. Regular updates and maintenance are essential to handle large data volumes and maintain system performance. The MDMS supports the storage and processing of the meter data, without which remote reading of the meters would not be possible.
CIS	The CIS manages customer data, billing, and account information. It integrates with AMI to provide accurate billing, customer service, and support functions, ensuring seamless customer interactions and efficient operations. The CIS enables meter reading benefits, by using the data gathered by the MDMS to support more accurate billing and making the meter data accessible to support customers with billing or usage questions.
Load Settlement	AMI provides the interval usage data needed to support more accurate load settlement by measuring customer consumption on an hourly or sub-hourly basis rather than relying on class-based load profiles. A modern load settlement system is necessary to process AMI interval data at scale and align retail usage information with ISO-NE settlement requirements. This improves transparency and accuracy in how energy and capacity costs are calculated and allocated.
Organizational Readiness	Involves the establishment and operation of a Project Management Office ("PMO") and Change Management Office ("CMO") to support the transition to AMI. The PMO and CMO ensure effective project planning, execution, and monitoring before and during deployment to ensure a smooth and successful implementation.

Necessary Infrastructure and O&M Costs	Necessary Infrastructure and O&M Description
	Effective project planning and organizational readiness is critical to effectively implement the new meter reading processes and new data acquisition throughout the entire organization. Changes to organizational structure and roles and responsibilities will also be necessary and will be addressed via organizational change management ("OCM") and training programs.
Contact Center	Involves the incremental personnel and resources required to support the call center during the meter exchange period and other AMI related activities. This includes training for contact center staff to handle new types of customer interactions and ensures that they have the tools and information needed to provide effective support. The new meter reading process and amount of new data available to customers will require additional resources in the contact center to support customer inquiries about billing or usage data.
Incremental Labor	Incremental Labor includes the additional personnel required for the installation, operation, and maintenance of AMI systems and temporary labor for deployment phases and ongoing staff for continuous operations and support, ensuring smooth and efficient system functionality. Installation, operation, and maintenance of the new AMI systems are necessary to make sure that the meter reading and reduced labor benefits of the AMI meters are fully available.
Revenue Assurance (Non-Technical Line Loss)	Includes the additional resources, materials, and equipment needed to act on improved theft and tamper insights from AMI data. AMI meters provide customer usage data and tamper detection capabilities that help the Company better identify and investigate unbilled usage. Additional revenue assurance investigators and resources are needed to address the increase in identified cases and fully realize benefits from recovered revenue and avoided losses.
OMS Integration	The Company's existing OMS can integrate and utilize AMI data to enhance outage detection, response, and restoration processes. This integration allows for more accurate identification of outage locations, faster restoration times, and improved communication with customers during outages.

Necessary Infrastructure and O&M Costs	Necessary Infrastructure and O&M Description
	The ability to detect outages and identify outage locations is necessary for reducing NTFs.
Customer Experience Portal	The Customer Experience Portal provides a digital platform for customers to access their detailed energy usage data, billing information, and personalized insights. The customer experience portal will serve as one method of informing customers of outages.
Engineering and Customer Usage Analytics	Utilizes advanced data analytics to identify unbilled usage, usage anomalies, transformer loading issues, and other grid performance concerns. This helps in optimizing grid operations, improving service reliability, and providing actionable insights for both the Company and its customers. VVO is a key use case identified by the Company for analytics, ensuring that VVO is operating to maximize benefits.
Green Button Connect	Green Button Connect enables customers to securely access and share their energy usage data with authorized third-party providers of energy products, applications, and services. The platform supports customer energy management, energy efficiency opportunities, DER participation, and other data-enabled services.
VVO Enablement	To enable VVO capabilities, the Company will need to deploy line devices such as voltage regulators, capacitors, and LTC controllers at substations, and enhance and integrate systems to use AMI data and support voltage reduction and optimization. Without investment in VVO systems, software, and hardware, these benefits cannot be realized.
Customer Engagement	Engaging customers and creating an AMI Customer Engagement Plan is critical to unlocking the full benefits of AMI. This includes pre-installation communications, education on how to use the new technology, understanding bills, and participating in demand response programs.

Necessary Infrastructure and O&M Costs	Necessary Infrastructure and O&M Description
	Educating customers is important as meter technology is being deployed, and the methods of collecting their usage data are changing. A digital portal will be developed to enhance customer engagement.
Cybersecurity	Costs to ensure security and privacy of, and access to, AMI data. This includes implementing security protocols, regular monitoring, and updating defenses to protect AMI infrastructure from cyber threats. Costs also cover security software, training, and incident response planning. Ongoing efforts to enable secure access to AMI data is necessary for the Company to deliver this benefit over the 20-year program.
Data Storage and Processing	A solution to store mass quantities of AMI data every day to be used to enhance business functions. This includes data processing technologies that ensure data integrity and accessibility, supporting analytics and operational improvements. Getting meter data on a more regular cadence will require investment in data storage and processing. These investments are also necessary to ensure that billing data is accurate.

Figure 18 shows the dependent benefits for each cost category. Descriptions of each benefit can be found in the table below.

Figure 18 – Dependent Benefits for each Cost Category

Costs Section	3.B.1.i – Meter Reading	3.B.1.ii – Avoided Meter Capital	3.B.2.i – Remote Account Connect/Disconnect	3.B.2.ii – No Trouble Found Calls Reduction	3.B.3.i – Volt/Var Optimization (VVO)	3.B.3.ii – Carbon Reduction	3.B.4.i – Asset Optimization	3.B.4.ii – System Costs Avoidance	3.B.5.i – Advanced Engineering Analysis	3.B.5.ii – Avoided Connectivity Survey	3.B.6.i – Improved Restoration Significant Storms	3.B.6.ii – Improved Restoration Blue Skies	3.B.7.i – Reduced Bad Debt	3.B.7.ii – Reduced Theft & Non-Technical Line Loss	3.B.7.iii – Reduced Soft Close Loss	3.B.8.i – Time of Use /Time Varying Rates	Detailed Billing Data and Notifications (Non-Quantifiable)
3.D.1.i – Meters	X	X	X	X	X	X	X		X	X	X	X		X	X	X	
3.D.1.ii – Undepreciated Meter Balance	*Undepreciated Meter Balance does not materially support any benefits*																
3.D.2.i – Communications	X		X	X	X	X	X	X	X	X	X	X		X	X	X	
3.D.3.i – MDMS	X			X	X	X	X	X	X	X	X	X		X	X	X	
3.D.3.ii – CIS	X		X	X		X	X	X						X	X	X	
3.D.3.iii – Load Settlement																X	
3.D.4.i – Organizational Readiness	X	X	X	X	X	X	X	X	X	X	X	X					
3.D.4.ii – Contact Center	X		X					X								X	
3.D.4.iii – Incremental Labor			X											X	X		
3.D.4.iV – Revenue Assurance (Non-Technical Line Loss)			X	X		X								X			X
3.D.5.i – OMS											X	X					
3.D.5.ii – Customer Experience Portal			X													X	X
3.D.5.iii – Engineering and Customer Usage Analytics					X	X			X					X	X	X	
3.D.5.iv – Green Button Connect	X				X	X			X								
3.D.6.i – VVO Enablement					X	X	X			X						X	
3.D.7.i – Customer Engagement	X		X											X	X	X	
3.D.8.i – Cybersecurity	X		X	X	X	X	X	X	X	X	X	X		X	X	X	
3.D.8.ii – Data Storage and Processing	X			X	X	X	X		X	X	X	X		X	X	X	

Dependent Benefits	Dependent Benefits Description
Meter Reading	The automation of meter reading through smart meters eliminates the need for routine manual readings, reducing O&M costs to perform monthly AMR meter reading and billing activities. It enables near real-time data collection, leading to more accurate billing for customers, while also improving the Company's operational efficiency.
Avoided Meter Capital	The deployment of AMI meters reduces the need for investment in AMR and bridge meter replacements, leading to cost savings in meter capital expenditures.
Remote Account Connect/Disconnect	Meter connects and disconnects can be automated through AMI, reducing the need for on-site visits. This increases operational efficiency, speeds up response times, and lowers costs associated with manual processes.

Dependent Benefits	Dependent Benefits Description
NTF Calls Reduction	AMI meters provide accurate data that helps to identify and resolve issues remotely, thereby reducing the number of unnecessary site visits where no issues are found on the supply side of the meter.
VVO	AMI provides the data that enables the Company to monitor and maintain voltage levels and optimize power flow using VVO. This reduces and stabilizes voltage levels, lowers customer energy costs, minimizes energy waste, and balances load distribution, enhancing overall power quality, grid performance and lifespan.
Carbon Reduction	AMI supports carbon reduction by enabling more efficient energy usage through VVO techniques. The AMI meters enable this benefit through programs like VVO but also through some outcomes like reduction in truck rolls.
Asset Optimization	The detailed data provided by AMI meters will allow the Company to better understand consumption patterns and grid performance, leading to more informed system planning and optimization. This enables more accurate forecasting, better asset utilization, and targeted infrastructure investments, ultimately improving grid reliability and efficiency.
System Cost Avoidance	Replacement of systems and devices to enable AMI avoids the costs of maintaining and eventually replacing these assets over the course of business as usual. Avoiding the cellular costs for the survey meters would not be possible without the communications upgrades necessary to get the meter data from the field back to the Company's systems.
Advanced Engineering Analysis	AMI meters may enable the Company to identify potential issues before they result in outages, allowing for proactive maintenance and planning. This reduces the frequency and duration of outages, improving service reliability and customer satisfaction. The AMI meters provide the data that allows the Company to identify potential issues and plan for the necessary response.
Avoided Connectivity Survey	AMI minimizes the need for manual connectivity surveys by providing continuous, near real-time data on connectivity status. Utilities can rely on real-time insights provided by AMI to maintain a well-functioning, optimized grid without the labor-intensive and costly process of manual connectivity surveys. The AMI meters are critical in providing the data necessary to eliminate the need for a connectivity survey.
Improved Restoration – Significant Storms	AMI systems provide enhanced grid visibility and control, enabling automatic detection of outages during significant storms. This will allow the Company to detect and respond to outages more quickly and with greater situational awareness, minimizing downtime,

Dependent Benefits	Dependent Benefits Description
	speeding up restoration efforts, and enhancing overall service reliability. The AMI meters are critical in providing this data and situational awareness.
Improved Restoration – Blue Skies	AMI systems provide enhanced grid visibility and control, enabling automatic detection of outages during blue sky days. This will allow the Company to detect and respond to outages more quickly and with greater situational awareness, minimizing downtime, speeding up restoration efforts, and enhancing overall service reliability. The AMI meters are critical in providing this data and situational awareness.
Reduced Bad Debt	AMI-enabled remote connect and disconnect functionality allows the Company to manage service status more efficiently without requiring a field technician visit. With a robust customer education effort, AMI can improve the effectiveness of collections processes, support faster action on delinquent accounts, and reduce uncollectible balances, lowering costs for all customers.
Reduced Theft and Non-Technical Line loss	AMI systems enhance the detection and prevention of energy theft by providing detailed consumption data that can identify irregular usage patterns. This reduces losses due to unauthorized use and minimizes the need for write-offs. These functions require installation of the meters to provide the necessary data.
Reduced Soft Close Loss	AMI enables remote turn-on and turn-off capabilities, which allow the Company to deactivate service at inactive premises without requiring a truck roll. This reduces unbilled usage that can occur between customer move-out and move-in, while lowering the cost to disconnect and reconnect service in soft-close scenarios.
TOU/TVR	TOU/TVR encourages customers to shift their energy usage to off-peak hours, reducing demand during peak times and lowering overall energy costs. These pricing models help balance the grid, decrease the need for expensive peak generation, and would provide cost savings to the Company and its customers. These rates depend on the interval data provided by AMI meters to accurately bill customers and incentivize behaviors.
Detailed Billing Data and Notifications (Non-Quantifiable)	The customer experience portal will house and manage the preference center for AMI-enabled notifications and data sharing. Preferences include notifications, data sharing, and others.