The Narragansett Electric Company
d/b/a Rhode Island Energy

Advanced Metering Functionality Business Case and Attachments

Schedule PJW/WR-1

Book 2 of 3

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Executive Summary

EXECUTIVE SUMMARY

The Narragansett Electric Company d/b/a Rhode Island Energy (referred to herein as "Rhode Island Energy" or the "Company") presents this Advanced Metering Functionality Business Case (referred to herein as the "AMF Business Case" or "Business Case")[1] seeking approval for full-scale deployment of advanced metering functionality ("AMF")[2] across its electric service territory in Rhode Island.

The need to replace automated metering reading ("AMR") with a full-scale AMF is driven by the convergence of the following three factors:

1) Current electric meter fleet needs to be replaced because it is reaching the end of design life and is obsolete and will not scale;

2) Ambitious Climate Mandates (as defined below) require greater visibility and grid modernization with increased operational capability to achieve while enjoying system safety and reliability; and

3) Evolving customer expectations and the desire to make more informed energy choices require advanced metering functionality.

Deploying and using AMF to its full potential is essential to Rhode Island Energy's continued ability to provide safe, affordable, reliable, and sustainable energy as the State transitions to a clean energy future. AMF also is critical to Rhode Island Energy's ability to improve reliability and enhance customer satisfaction.

Now is also the right time for a full-scale AMF conversion because most of the existing meters are reaching the end of their design life. Thus, Rhode Island Energy needs to replace meters, and the alternative to AMF would be a like-kind AMR technology replacement. Accordingly, there is no "do-nothing"option.

[1] This AMF Business Case replaces the filing that The Narragansett Electric Company previously submitted on January 21, 2021, while still under National Grid USA ("National Grid") ownership. Rhode Island Energy filed a Notice of Withdrawal of that filing on September 12, 2022.

[2] AMF refers to the functionality provided by advanced meters, also referred to as smart meters, while automated metering reading ("AMR") refers to the presently used metering systems solution in Rhode Island to collect billing information with a "drive-by" technology. AMF is a broader concept than Advanced Metering Infrastructure ("AMI"); AMI commonly refers only to the smart meters themselves. AMF refers to the functionality that comes from the broader deployment of hardware and software solutions needed to utilize the smart meter data in a timely and efficient manner. The Company uses the term AMF universally throughout this filing to signify that the Company considered the viability of non-smart meter solutions.

There also are climate and other clean energy statutory mandates (collectively, the "Climate Mandates")[3] that provide the basis for expectations that distributed energy resources ("DERs") and electrification on our electric grid will be increasing. Rhode Island needs an AMF platform to provide enhanced customer awareness, the wherewithal for dynamic rate offerings, and system visibility for grid operators to manage increased system complexity from intermittent distributed energy resources and emerging variable load from electric vehicle charging. The unpredictable nature of DERs will cause unforeseen power flows and voltage fluctuation, which Rhode Island Energy's electric grid operators currently cannot see or control, leading to decreased reliability and safety performance. Additionally, DERs can compromise the effectiveness of protection schemes, causing equipment failures on the system. AMF provides grid-edge sensing that can detect voltage anomalies and pinpoint system outages, which AMR cannot. AMF also is uniquely capable of providing energy usage data with the granularity and frequency needed for delivering energy insights, personalized energy efficiency ("EE"), and demand response ("DR") to customers. The three converging factors, discussed above, demonstrate that an investment in AMF is the right decision for Rhode Island and its customers. Just comparing costs of replacing AMR meters to the cost of AMF meters ignores the fact that AMR meters are incapable of delivering AMF-associated benefits that are necessary to enable the Rhode Island future energy vision. The Company's consideration of alternative metering solutions and their relative functionalities further bolsters the conclusion that full-scale AMF deployment now is the right decision.[4]

Additionally, this Business Case demonstrates that AMF is a necessary first step toward grid modernization because it provides near real-time granular interval data, voltage information and automatic outage notification that become necessary inputs to grid modernization software and automated field devices. These capabilities can help pinpoint problems and initiate a variety of actions using grid modernization investments such as automatic fault isolation, improved restoration efficiency and voltage optimization. AMF also is an enabling platform for other applications such as gas metering automation, gas leak detection, and DER management. Although these capabilities are beyond the scope of this filing, they are tools to help achieve the future energy vision in Rhode Island that an investment in AMF now will help facilitate. Accordingly, filing the AMF Business Case before the GMP allows the Company, regulators,

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[3] The 2021 Act on Climate set forth enforceable, statewide, economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% by 2040, and to achieve net-zero emissions by 2050. The 2022 amendments to the Renewable Energy Standard further accelerate the shift to renewable energy resources by requiring 100% of electricity used in the State be generated by renewable energy resources by 2033.

[4] Rhode Island Energy is intentionally filing its AMF proposal separately – in docket and in time – from its Grid Modernization Plan ("GMP"). By filing its AMF proposal in advance of the GMP, the Company emphasizes the conceptual value of AMF, highlighting both the unique benefits it provides independent of GMP and the value AMF delivers as an enabling platform for the proposed GMP investments. Although the filings are distinct, the Company has ensured compatibility between its AMF and GMP filings.

and stakeholders to get a jumpstart on understanding AMF as an enabling platform and evaluating its value proposition.

Rhode Island Energy is proposing to:

- Replace 524,677 electric AMR meters with electric AMF meters ("Electric AMF").
- Design and build a fixed, secure radio frequency ("RF") mesh network for Electric AMF that anticipates supporting future requirements for electric vehicle charging, distributed energy resources, time-varying rate designs and gas network automation.
- Design and implement the back-office IT systems required to receive and process the data received from the Electric AMF meters and RF mesh network devices.
- Provide the functionality necessary to achieve the objectives of Rhode Island customers, the Climate Mandates, and utility operations.

This is an opportunity to upgrade Rhode Island Energy's electric meters to enable the visibility and control needed to keep the electric grid operational in the clean energy future. In addition to being needed to "keep the lights on," the AMF project will provide approximately $729.2 million in benefits using a 20-year net present value ($2022 NPV) analysis, compared to a $188.0 million (20-year $2022 NPV) investment, yielding a 3.9 BCA ratio. Rhode Island Energy calculated the $729.2 million ($2022) total benefits which include Utility, Customer and Societal in accordance with the Rhode Island-specific benefit-cost framework that the Rhode Island Public Utilities Commission ("PUC") adopted in Docket No. 4600 (the "Docket 4600 Framework").[5] When evaluating only the Utility benefits, the AMF project will provide $354.7 million ($2022) in benefits, yielding a 1.9 BCA ratio. Figure ES.1 shows the total benefits and costs of the AMF project, both nominal dollars and $2022 Net Present Value ("NPV").

[5] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 at 23 (July 31, 2017).

Figure ES.1: Benefits and Costs of Full AMF Deployment

Rhode Island Electric						
Electric Benefits and Costs of Full AMF Deployment						
As of November 12, 2022						
	Utility Savings	**Direct Customer Savings**	**Societal Savings**	**Total Savings**	**AMF Costs**	**Benefit/ Cost Ratio**
Nominal ($M)	$ 529.7	$ 314.5	$ 215.1	$ 1,059.3	$ 289.0	3.7
NPV ($M)	$ 354.7	$ 213.2	$ 161.2	$ 729.2	$ 188.0	3.9

Approval of this AMF Business Case will provide the capability to address unmet customer needs, replace AMR technology that is at the end of its design life and maintain a safe, reliable electric system while taking steps to achieve the State's Climate Mandates. Rhode Island Energy's AMF deployment will:

- Empower customers to better manage their energy usage
- Enable customer-side technologies that automate end-user response to TVR
- Create customer education and engagement programs with information and tools to optimize their energy consumption
- Help customers reduce their energy burden and address income-eligible and vulnerable customers' needs.

Section 1

SECTION 1: INTRODUCTION AND APPROACH

This Section presents the current state of metering in the Company's electric service territory, as well as Rhode Island Energy's strategic outlook for AMF to address the customer, operational and clean energy present and future needs. The Section summarizes the legislative and regulatory history for AMF in Rhode Island and discusses how Rhode Island Energy worked with National Grid to understand their Updated Advanced Metering Business Case, which became a foundational contribution to this Business Case. This section also includes a table that summarizes twenty-three elements called for by the Amended Settlement Agreement (ASA) along with identification of where Rhode Island Energy included those elements in the Business Case. This section also describes Rhode Island Energy's affiliate's AMF and GMP business results as context and a playbook for success that can be adopted in Rhode Island.

Rhode Island Energy submits this AMF Business Case following extensive efforts to evaluate metering options, considering the condition of the existing AMR meter fleet that is now nearing the end of its useful design life and the emerging requirements that are being driven by evolving customer expectations and the State of Rhode Island's Climate Mandates.

1.1 The Need

There is a need to replace existing AMR metering infrastructure because of the convergence of the following three factors:

1. Current electric meter fleet needs to be replaced because it is reaching the end of design life, is obsolete, and will not scale;

2. Ambitious Climate Mandates requires greater visibility and grid modernization with increased operational capability to achieve while enjoying system safety and reliability; and

3. Evolving customer expectations and the desire to make more informed energy choices require advanced metering functionality.

The issue is multi-pronged. From a meter perspective, along with ensuring safe and reliable service, the Company has a regulatory obligation to address the aging meter asset that is approaching the end of design life. The capability of the current AMR technology does not provide the functionality necessary to meet the State's Climate Mandates. The role and characteristics of the electric distribution system are rapidly changing due to hosting increasing penetration of DERs. DERs cause voltage swings, hide native load, and create multi-directional power flow which impacts electric grid operations and protection schemes. Currently, distribution system operators have limited granular visibility and situational awareness of the distribution system, making it increasingly difficult to operate safely and reliably as the operating environment becomes more complex and uncertain. Additionally, time varying rate ("TVR") structures can provide incentives for energy efficiency, demand response and peak shifting to reduce costs for customers and improve system utilization. The existing AMR technology is insufficient to support such structures.

1.2 Electric AMF Is Needed for Rhode Island's Future Energy Vision

Electric AMF described in this Business Case is an enabling platform that is both strategically and operationally essential for Rhode Island Energy as well as for Rhode Island to achieve its long-term energy vision. It will advance the development of a safer and modernized electric grid, one that provides more granular billing and usage information for customers, more frequent system information for grid operators, and advanced functionality – all of which are needed to enable the Climate Mandates, while protecting electric system safety and reliability.

This AMF Business Case reflects the significant changes that are occurring across Rhode Island Energy's system as a result of the State's Climate Mandates to achieve net-zero carbon emissions by 2050 and 100 percent renewable energy by 2033, all amidst changing customer behaviors and expectations. These changes are marked by the increasing adoption of additional renewable generation sources, including DER. Also, this AMF Business Case contemplates beneficial electrification, electric vehicles, electric heat pumps, and advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business. These trends are accelerating the shift from the original one-way flow of electricity from the utility distribution system to the customer, to two-way power flow, necessitating a hastened transformation of the distribution grid to safely, reliably, and efficiently deliver electric service to customers.

This accelerated transformation creates increasing operational uncertainty and system complexity due to the intermittent and unpredictable nature of DERs that are interconnected to the distribution system. The key for successful modern-day operations with significant DER penetration is continuous situational awareness achieved by bringing together multiple streams of important data and synthesizing it in a cogent way to provide real-time, relevant information in a single location.

AMF brings greater operational visibility and situational awareness to ensure safe and reliable operations and to have more dynamic interaction with customers so they can make more informed decisions and feel empowered to take more active control of their energy usage. This greater operational visibility requires continuous two-way flows of data and information between Rhode Island Energy and its customers. The current practice of obtaining a monthly snapshot of electricity usage with AMR has been historically sufficient for billing purposes; however, now the demand for frequent system and usage information is an essential meter technology requirement that goes well beyond billing. Upgrading the current AMR meter fleet to AMF meters will enable the necessary continuous data and information flow.

Purpose, Benefits and Outcomes

The Business Case's purpose is to demonstrate the critical need for the Electric AMF which:

1. Provides two-way communication capability to the meter, providing data to the utility and customer and enabling the utility to remotely monitor and manage the meter.
2. Provides capability to capture 15-minute interval usage data using a fixed communication network to read meters remotely,
3. Provides Rhode Island Energy with much needed and significantly more information compared to that available today,
4. Integrates systems to maintain the data and derive needed information from it, and
5. Provides useful energy data to customers in a timely manner.

This AMF Business Case documents the need for: (a) replacing the legacy AMR system with AMF-enabled meters along with a communications network and back-office systems that can transport and assimilate the data to identify and enable actions to deliver meaningful and positive outcomes, both in terms of system operations and customer actions; (b) reducing overall operating and maintenance ("O&M") costs; (c) improving the safety and reliability of the electric system; (d) empowering customers to better manage their energy usage and DER investments; and (e) achieving carbon emission reductions and other societal benefits.

AMF enables benefits for customers, the Rhode Island Energy system, and the Rhode Island environment. Customers can benefit through energy insights, personalized energy efficiency ("EE"), demand response ("DR"), TVR and remote outage notification. Rhode Island Energy can benefit from: (i) avoided costs of purchasing replacement AMR meters costs, (ii) avoided sensor costs, (iii) enhanced planning, (iv) enhanced operator visibility and (v) control, remote meter connect/disconnects, (vi) automated outage notification and (vii) improved asset management.

The time to deploy AMF in Rhode Island is now. In addition to the time-sensitive reasons discussed above, AMF also provides an enabling platform capable of satisfying emerging electric system requirements. The energy sector is going through a period of transformational change like none other in its history. Major forces impacting the business include the Climate Mandates, digitalization, proliferation of energy management technologies, evolving societal expectations, increased regulations on operating and cyber security requirements, customer expectations for more options, electrification of transportation and heating, energy efficiency efforts, tech-driven products such as LED lighting systems, and electrical energy storage at large scale. This energy transformation recasts functionality requirements that will be needed in the future; this AMF proposal offers capabilities and a platform that can satisfy the future needs and offers customers the opportunity to better manage their energy usage.

Accordingly, in addition to the specific value and benefits derived solely from the implementation of AMF to Rhode Island's electric customers, Rhode Island Energy's AMF proposal also is a critical enabling platform because it is integral to achieving GMP functionality. Specifically, GMP functionality such as enhanced observability of the distribution network, improved grid optimization, and DER management and enhanced distribution grid control all are needed to build a flexible grid to integrate more clean energy resources safely and reliably. All these GMP functionalities and more require AMF as an enabling platform. AMF also enables dynamic TVR structures that can result in more accurate pricing, more efficient energy sector, and more equitable allocation of costs.

Deployment Strategy and Schedule

The Company is proposing a three and one-half (3½) year schedule including meter pre-sweeps, network development, electric meter deployment and stabilization. The Company must deploy the communications network and back-office systems first to facilitate the effective roll-out of meter exchanges. The Company will perform back-office integration in three phases: (i) leading up to meter deployment, (ii) during meter deployment to provide billing continuity, and (iii) after the AMF meters are fully deployed to achieve additional benefits that AMF enables. Rhode Island Energy will engage with customers before, during, and after meter deployment. To meet the desired schedule, the Company needs to incur some costs before the anticipated approval date of this proposal that are associated with systems development, AMF meters, RF network equipment and planning. Orders need to be placed before the anticipated Business Case approval to ensure equipment is available in time to begin field installations as set forth in the project schedule. Expenses for preliminary RF network planning will also be needed to prepare for the scheduled start of the network deployment. The Company designed the project schedule in this manner to facilitate AMF capability for Rhode Island customers as soon and as efficiently as possible.

1.3 Rhode Island Energy Benefits From PPL Corporation's AMF Experience

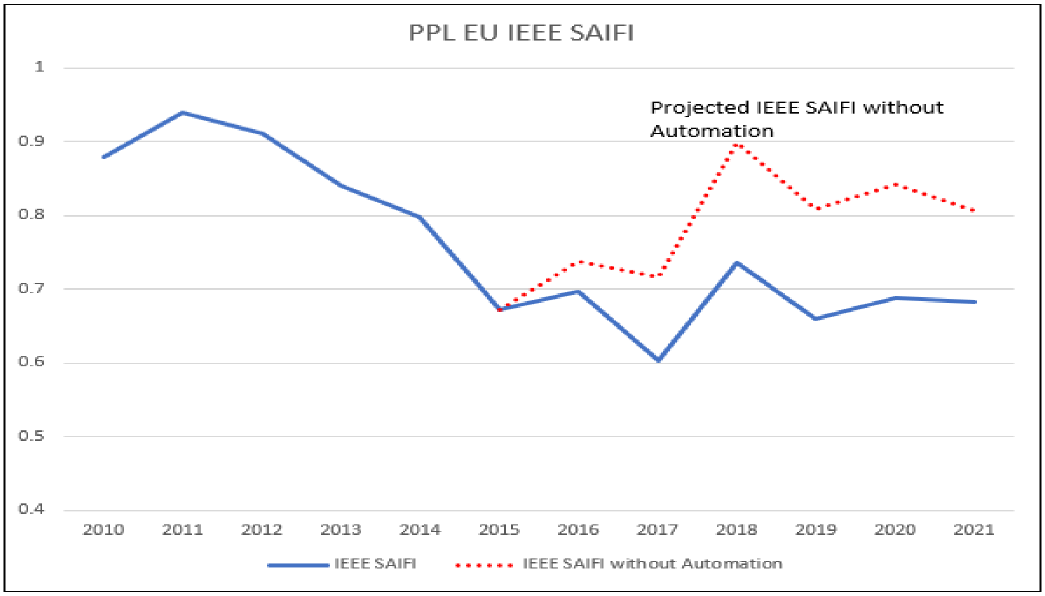
On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL"), acquired 100% of the outstanding shares of common stock of The Narragansett Electric Company from National Grid USA ("National Grid") (the "Acquisition"). Rhode Island Energy will benefit from PPL's AMF insights learned through its prior deployment experience in its other jurisdictions, as discussed below and throughout this AMF Business Case.

PPL has installed advanced meters for all its Pennsylvania customers and has begun meter installation for its Kentucky customers. In Pennsylvania, PPL implemented its first-generation automated meter reading system from 2002 to 2004; the second-generation advanced meter reading infrastructure was installed from 2015 to 2019 and is currently in service. PPL will bring its recent and extensive experience in deploying and using these advanced meters to maximize the efficiency and effectiveness of the Rhode Island Energy AMF deployment. PPL's substantial experience in realizing AMF benefits for customers and network operations has brought PPL to the forefront of industry best practices in the use of advanced metering capabilities. PPL is constantly implementing new programs and use cases to allow customers greater access and control over their consumption and energy costs, while also providing advanced capabilities to better manage the distribution network.

PPL has a rich tradition of utilizing long-range planning processes to identify and build optimal infrastructure and supporting technology platforms to improve safety, reliability and customer satisfaction while driving down O&M costs through automation, and PPL will bring that practice to Rhode Island Energy's AMF deployment. PPL has learned through experience that the information, visibility, and capability from the new technologies embodied in the AMF program are foundational and crucial to delivering Rhode Island's renewable energy and greenhouse gas reduction mandates while continuing and enhancing Rhode Island Energy's core mission in delivering safe, reliable, and affordable electricity to Rhode Island Energy's customers.

Customers have benefited from PPL Electric's AMF and GMP investments in Pennsylvania. By applying the technologies in tandem, the frequency of outages or System Average Interruption Frequency Index ("SAIFI") has improved over time as shown in Figure 1.1, below, where there is steady improvement (trending down) over the last decade after excluding IEEE Major Events. This significant accomplishment is a direct result of AMF and GMP investments, including automation of the electric distribution grid with smart recloser installations, microprocessor relays, and more than 1.4 million second-generation automated meters.

Figure 1.1: PPL EU SAIFI Trend (Enabled by AMF)



PPL is a proven innovator, having been one of the first utilities in the country to systematically install Fault Location Isolation and Service Restoration ("FLISR") technology to automatically sectionalize the electric distribution system in blocks of approximately 500 customers. This investment has changed how the distribution system operates by automating the distribution network reconfiguration, minimizing the number of customers impacted by a power outage, and enabling more effective and efficient response to restore service. These reliability improvements were made possible, in part, by Last Gasp and Power Up alert information coming from AMF meters.[6] Using the AMF informational platform for FLISR automation, outages are isolated to small customer blocks using automated distribution switching so that fewer customers experience an outage. Outage information and isolation enable restoration crews to be more efficiently dispatched to pinpointed outage locations, resulting in reduced outage restoration times. To demonstrate the business impact, Figure 1.1 also provides an approximation of what IEEE SAIFI would have been without automation. Business results are a direct result of full-scale deployment of FLISR, second-generation AMF, and supporting operational tools such as the Advanced Distribution Management System ("ADMS"). PPL is bringing a basic ADMS system (referred to herein as "ADMS Basic") to Rhode Island Energy as a condition of the Acquisition and as part of Rhode Island Energy's transition to PPL's systems. Rhode Island

[6] Last Gasp is an automatic notification by the AMF meter indicating an interruption of electrical service at the meter. Power Up is an automatic notification by the AMF meter indicating the restoration of electrical service at the meter.

Energy does not intend to seek recovery of its allocated share of the costs of the ADMS Basic system from Rhode Island customers.[7] A discussion of how Rhode Island Energy will utilize ADMS going forward to integrate with other grid modernization functionalities is provided in Section 4.2 of this Business Case.

PPL has been nationally recognized for its successful AMF and GMP deployments as examples of technology innovation and pioneering achievements in the utility industry.[8]

PPL's AMF experience in other jurisdictions will reduce the uncertainty of expected AMF costs and benefits and deriving synergies utilizing pre-existing integration, processes, and procedures that have already proven successful. PPL's prior AMF deployment and operational experience will offer efficiencies, costs savings, and functionality in Rhode Island that would have otherwise taken more time and expense to attain. For example, the functionality that PPL has already developed and provided by integrating operational systems with last "gasp" AMF information (communication from the AMF meter to the company's operating system of an electrical outage) will be made available to Rhode Island customers as soon as the customer meter is exchanged. Without having this integration already completed, it would likely have taken considerable time for system integration necessary for business process efficiencies and resulting improvements in the customer experience.

With this AMF Business Case, PPL's deployment experience can be readily applied to Rhode Island Energy customers so they can enjoy similar benefits as other PPL customers. The AMF business case incorporates PPL's business philosophy, lessons from deployments in other jurisdictions, and incremental benefits that are achievable based upon prior experience. The new

[7] ADMS Basic is the ADMS platform PPL currently has in place for its Pennsylvania electric utility, PPL Electric Utilities Corporation ("PPL Electric"), and which Rhode Island Energy will have in place for its operations upon exit from the Transition Services Agreement with National Grid USA Service Company, Inc. As part of the Acquisition approval, PPL committed that it would not seek recovery from customers of any transition costs. Part of that transition includes bringing ADMS Basic to Rhode Island Energy. Accordingly, PPL is providing the ADMS Basic platform to Rhode Island Energy, the allocated costs of which will not be recovered from Rhode Island customers. ADMS Basic is an enhancement from the National Grid distribution management system. PPL and Rhode Island Energy plan to propose enhancements to ADMS Basic (which are not a part of the transition) to increase functionalities and benefits. In this AMF Business Case, the defined term ADMS Basic refers specifically to the software that PPL is providing to Rhode Island Energy as part of the transition.

[8] In 2019, PPL Electric won the Reliability One Best Improved Utility for Reliability based upon a measure of reliability performance data that was certified as part of the program. According to IEEE and EEI analyses, PPL Electric has performed in the first quartile for SAIFI every year for the last seven (7) consecutive years. PPL has also demonstrated capability and been repeatedly recognized for its ability to satisfy customers. According to the 2021 Sustainability Report, PPL has been awarded 58 total J.D. Power residential and business customer satisfaction awards in Pennsylvania and Kentucky combined. The strong record of customer satisfaction is statistically correlated to the ability to continuously reduce the number of sustained outages that customers experience.

technologies included in the AMF filing are designed to provide customers with greater control, choice, and convenience in managing their energy consumption. AMF technology will also help meet evolving customer expectations by enhancing outage management capabilities and enabling more convenient remote service connections. The investment serves as a foundation for an informational platform positioning Rhode Island Energy to gather, analyze and leverage information to better engage customers and to better enable other businesses to use the electric grid for new kinds of services. Whether as a platform for other service providers or as a customer-focused energy service firm, the Rhode Island Energy system will be an information-driven enterprise. The transition to an information-driven utility is designed to enable Rhode Island Energy to control long-term costs, increase customer choice, and enhance the flexibility needed to incorporate more clean energy resources.

1.4 Legislative and Regulatory History

The legislative and regulatory framework in Rhode Island provides the backdrop against which the need for AMF is apparent. The Rhode Island General Assembly enacted several pieces of legislation, which include, among others, the Climate Mandates. This legislative and regulatory framework includes, specifically, the Affordable Clean Energy Security Act of 2014;[9] the 2021 Act on Climate;[10] the 2022 bill requiring 100% renewable energy by 2033, and the Renewable Energy Growth Program ("REGP"). The REGP legislation, coupled with existing net metering policies that promoted customer-sited distributed generation projects, already has started increasing the penetration of customer-owned and third-party generation projects, known to cause bi-directional energy flows, voltage anomalies, and irregularities across the distribution system.

Although the General Assembly anticipated that the planned deployment of distributed generation could improve system resilience and reliability and advance the State's clean energy transition, it was also understood that achieving the goals depended upon modernizing the utility's grid architecture and employing new rate structures to equitably allocate the costs and benefits of investments across all customer classes.

The PUC recognized this need for modernization in Docket No. 4600, Investigation into the Changing Electric Distribution System (referred to herein as "Docket 4600"). In Docket 4600, the PUC adopted goals for a new electric system, the Docket 4600 Framework, and the rate design principles set forth in the Stakeholder report.[11] In doing so, the PUC found that the recommendations contained in the Stakeholder report provided "a pathway toward a more

[9] R.I. Gen. Laws §§ 39-31 *et seq*.

[10] R.I. Gen. Laws §§ 42-6.2 *et seq.*

[11] *See* Report and Order No. 22851 at 29.

modernized and efficient electric system."[12] The PUC subsequently issued a guidance document ("Docket 4600 Guidance Document") that set out and explained the goals, rate design principles, and the Docket 4600 Framework for use in future dockets.[13] The Docket 4600 Framework measures the benefits and costs of various programs and proposals to ensure that the regulatory practices are consistent across all utility-administered programs. Attachment A maps each of the benefit-cost categories of the Docket 4600 Framework to the BCA presented in this Business Case.

1.5 Amended Settlement Agreement ("ASA") Resolving Docket Nos. 4770 & 4780

In November 2017, the Company applied for approval of changes in electric and gas base distribution rates in Docket No. 4770,[14] along with a Power Sector Transformation Vision and Implementation Plan ("PST Plan") in Docket No. 4780.[15] The PST Plan proposed a suite of investments, including state-wide deployment of AMF, that would address Rhode Island's metering need and align the Company's energy infrastructure with the State of Rhode Island's clean energy policy objectives, consistent with the PUC's findings in Docket 4600 and the Docket 4600 Guidance Document.

On August 16, 2018, the Company, the Division of Public Utilities and Carriers ("Division"), the Rhode Island Office of Energy Resources ("OER"), along with the other intervening parties filed an Amended Settlement Agreement[16] ("ASA") that resolved all disputed issues in both dockets, which the PUC approved on August 24, 2018 in Docket Nos. 4770/4780.[17]

The ASA included an initial, limited set of grid modernization investments as part of a multi-year rate plan ("MRP"),[18] and further required the Company to file a comprehensive GMP and

[12] *Id*. at 22.

[13] *See Pub. Util. Comm'n's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid,* Docket 4600-A (October 27, 2017).

[14] *See* The Narragansett Elec. Co. d/b/a National Grid, Application for Approval of a Change in Elec. and Gas Base Distribution Rates, Docket No. 4770 (November 29, 2017).

[15] *See* The Narragansett Elec. Co. d/b/a National Grid, Proposed Power Sector Transformation Vision and Implementation Plan, Docket No. 4780 (November 28, 2017).

[16] *See* Amended Settlement Agreement, Docket No. 4770 (August 16, 2018).

[17] *See* Report and Order No. 23823, Docket Nos. 4770 & 4780 (May 5, 2020).

[18] The MRP was extended with the consent of the Division. *See* National Grid – Notification of Agreement between the Company and the Rhode Island Division of Public Utilities and Carriers regarding an Extension of the Term of the Multi-Year Rate Plan (July 15, 2021).

Updated AMF Business Case, which describes how each integrates with the other.[19] In addition, the ASA includes twenty-three requirements for the Company to address in the AMF Business Case, including a comprehensive benefit-cost analysis ("BCA") that fully incorporates the Docket 4600 Framework.[20]

The ASA requirements applicable to AMF are listed below in Figure 1.2. Rhode Island Energy has incorporated all requirements from the ASA into this AMF Business Case except for number 2 (performing BCA sensitivities for different meter deployment periods) and number 20 (requiring a combined New York/Rhode Island deployment proposal). These requirements are no longer applicable in the context of PPL ownership.[21] For convenience, the right column notes the Section(s) in this Business Case where each element in the ASA is addressed.

Figure 1.2: Amended Settlement Agreement Requirements Addressed in the Business Case

	Updated AMF Business Case Requirements per the Amended Settlement Agreement	**Business Case Section(s)**
1	A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed customer engagement plan	BCA: Section 11 and Attachment H CEP: Section 9 and Attachment F
2	An updated AMF deployment schedule with a BCA (using Societal Cost Test) for different meter deployment periods	Deployment: Section 8 and Attachment D BCA: Section 11
3	Revenue Requirement for AMF deployment	Section 12
4	Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF	Cost Recovery: Section 12 Deployment: Section 8 and Attachment D

19 *Supra* note 1.

20 *See* Report and Order No. 22851, *supra* note 5 at 23, 29.

21 PPL does not operate in New York and already has deployed AMF in Pennsylvania and is in the process of deploying AMF in Kentucky; therefore, a multi-jurisdiction scenario is not applicable to Rhode Island Energy's Business Case. Rhode Island Energy's BCA is based upon a 1 ½ year meter deployment period because it is more efficient, as concluded in National Grid's AMF proposal and PPL's AMF deployment in Pennsylvania. As a result, the BCA sensitivity for various meter deployment periods is no longer applicable and was not performed for this Business Case.

5	A proposal to allocate AMF costs among rate classifications	Section 12
6	Assumptions upon which a proposal for Time-Varying rates will be based	Section 13
7	A Data Governance Plan regarding customer, NPP, and third-party access to system and customer data in place with access to quality customer and billing data, along with appropriate privacy and security protections	Section 10 and Attachment G
8	Updated costs for AMF deployment based on information gained from procurement efforts	Section 11
9	Transparent, updated benefit cost analysis that fully incorporates the Docket 4600 Framework	Section 11
10	Investigation of alternative business models and ownership models	Section 7
11	Analysis of data latency	Section 5 and Attachment E
12	Deployment details	Deployment: Section 8 and Attachment D CEP: Section 9 and Attachment F
13	Role of non-regulated power producers, including articles to share customer information and customer engagement	Section 9 and Attachment F
14	Ownership model for assets and telecom	Section 7
15	Detailed AMF functionalities, how RI will achieve these functionalities, and a timeline for when those functionalities are available	Section 6
16	Identification of the most cost-effective way to achieve the functionalities, and how the functionalities align to policy objectives	Section 3

17	Explanation of whether the realization of those functionalities align to policy objectives will require additional future work and costs over 20 years	Section 6 and Section 11
18	Identification of what functionalities the AMF will achieve that are part of the grid modernization plan and which are in addition to the Grid Modernization Plan	Section 4
19	Identification of which functionalities are dependent on full-scale roll out instead of a targeted roll out	Section 3
20	Business case based on both a RI-only scenario and RI/New York scenario	Not applicable
21	A business case based on the length (duration) of meter deployment	Section 8, 11 and Attachment D
22	Identification of the critically linked parts of grid modernization and AMF	Section 4
23	Identification of whether the AMF solution would allow for proper net metering according to the tariff	Section 9

1.6 Stakeholder Engagement

The ASA also required engagement with stakeholders via a newly created PST Advisory Group or relevant subcommittee to develop the Updated AMF Business Case and GMP. Through the PST Advisory Group, a GMP/AMF Subcommittee was launched in October 2018.[22] The Subcommittee engaged over the course of numerous meetings between October 2018 and

September 2020.[23] Rhode Island Energy reviewed the power points and minutes from the prior PST meetings and interviewed employees who were in attendance to gain an understanding of

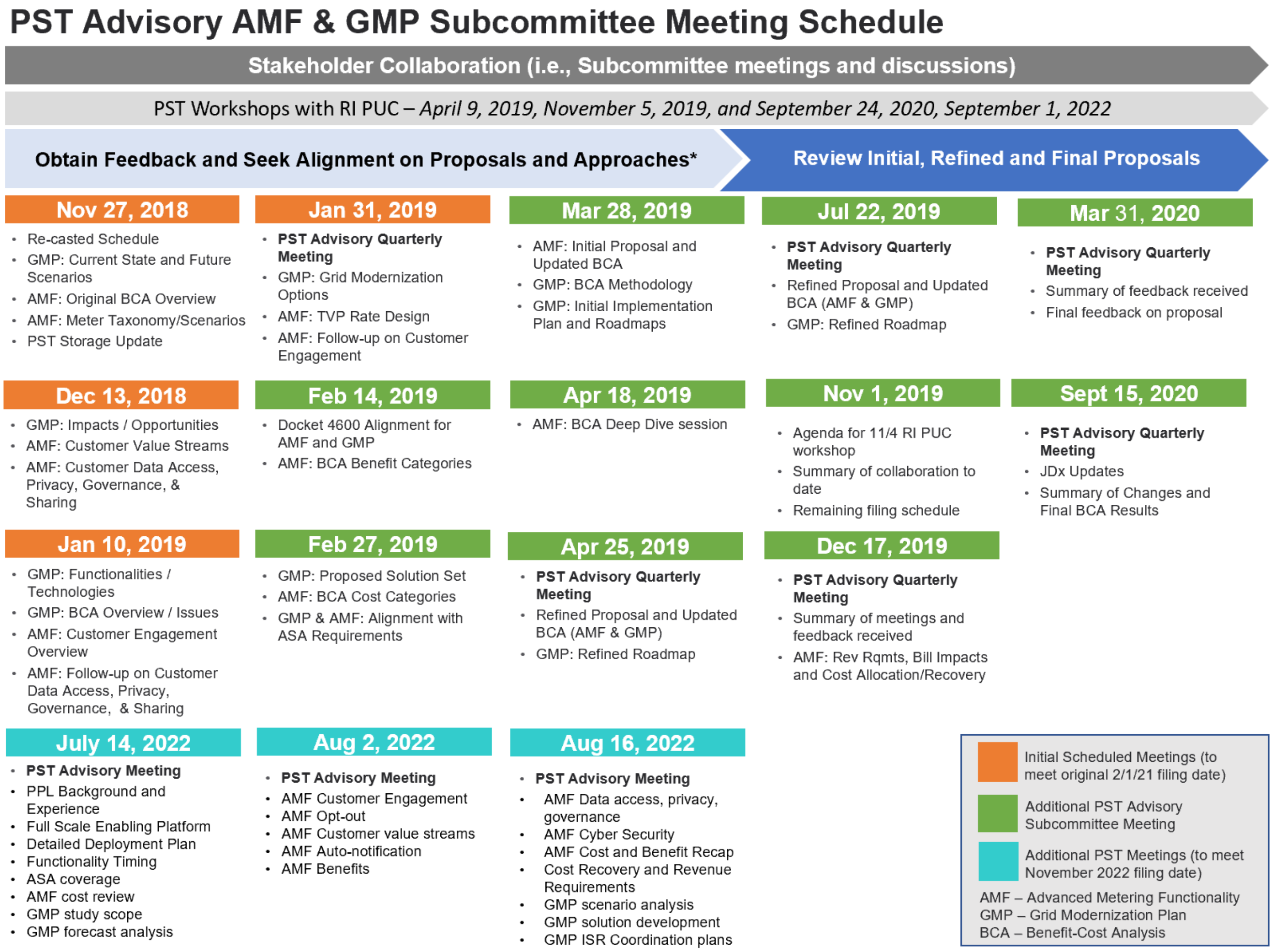
22 The PST Advisory Group members represent a broad spectrum of interests ranging from environmental and clean-energy groups to low-income, community, and business interests, as well as Non-regulated Power Producers ("NPPs").

23 The PST Subcommittees met regularly from October 2018 through September 2020. The meetings were sequenced such that the first set of meetings focused on detailed topical discussions of components contained in the

the history and input that was provided. The Company also arranged additional PST meetings to present the Business Case and get stakeholder input in July and August of 2022 in preparation for this filing. As a direct result of PST feedback, deeper discussions were held on network design, the process for exchanging commercial and industrial ("C&I") customer meters and their engagement, implementation approach for renters, low-income, non-English customers, specific information available on the customer portal and its timeliness, EV and DER projection methodology and assumptions to achieve GHG reduction targets, TVR availability and assumptions and customer behavior research. Figure 1.3 below illustrates the meetings and technical sessions with the AMF/GMP Subcommittee and the PUC.

National Grid Updated AMF Business Case, such as customer value streams, customer engagement, data privacy, rate design, and application of the Docket 4600 Framework to the BCA. Following these meetings, a set of milestone meetings were held to review the National Grid Updated AMF Business Case, which included the updated BCA and methodology, as well as associated revenue requirements, bill impacts, and cost allocation methodology.

Figure 1.3: PST AMF and GMP Sub-Committee Meeting Schedule



In addition to the scheduled meetings, the Company participated in a PUC-led workshop on April 9, 2019. On April 23, 2019, the PUC held an open meeting to discuss and provide additional feedback on the workshop. On November 5, 2019, and September 24, 2020, the PUC held technical sessions to receive updates on the various workstreams, including the work of the AMF/GMP Subcommittee.

Rhode Island Energy also participated in a technical session with the PUC regarding the Rhode Island Energy AMF Business Case on September 1, 2022. Rhode Island Energy incorporated input from all these meetings and sessions that is reflected in the content of this Business Case.

Section 2

SECTION 2: THE CURRENT STATE OF RHODE ISLAND ENERGY METERING AND PPL INSIGHTS

This Section provides a description of the current meter reading technology in the US and at Rhode Island Energy where asset age is approaching end of design life. Rhode Island Energy AMF insights that have been gained through PPL's prior experience will be beneficial for modernizing the aging metering infrastructure with AMF.

2.1 Background: Current State of Metering in the US

According to the U.S. Energy Information Administration, "In 2021, U.S. electric utilities had about 111 million advanced (*smart*) metering infrastructure (AMI) installations, equal to about 69% of total electric meters installations. Residential customers accounted for about 88% of total AMI installations, and about 69% of total residential electric meters were AMI meters."[24] That number is expected to increase in the coming years as approved implementation programs continue and proposals for approval are advanced in numerous states. The Edison Foundation's Institute for Electric Innovation ("IEI"), for example, had identified that more than fifty electric utilities across the United States had fully deployed smart meters as of the end of 2019.[25] Figure 2.1[26] shows the residential smart meter deployment progress by state as of 2021. Additionally, Wood Mackenzie, forecasts "the number of AMI meters installed in the country to grow from 112.4M in 2021 to 139.9M in 2026." [27]

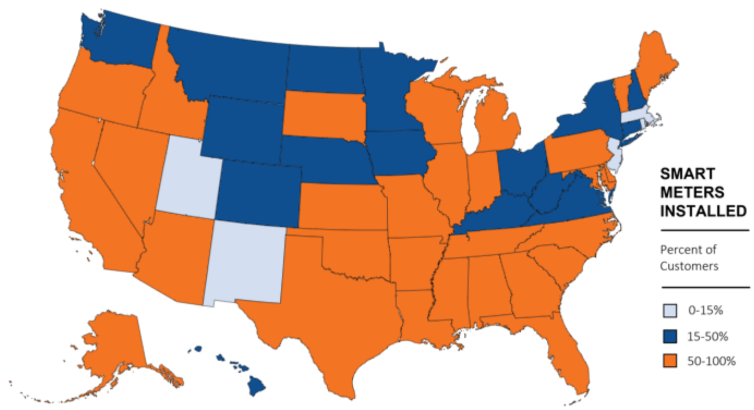
[24] U.S. Energy Information Administration, *How many smart meters are installed in the United States, and who has them?*, https://www.eia.gov/tools/faqs/faq.php?id=108&t=3 (November 2, 2021).

[25] *See* Adam Cooper & Mike Shuster, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid (2021 Update)*, Institute for Electric Innovation, https://www.edisonfoundation.net/-/media/Files/IEI/publications/IEI_Smart_Meter_Report_April_2021.ashx at 1-2 (April 2021).

[26] *Id.* at 1; *see also* U.S. Energy Information Administration, *Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files for 2021*, https://www.eia.gov/electricity/data/eia861/ (October 6, 2022).

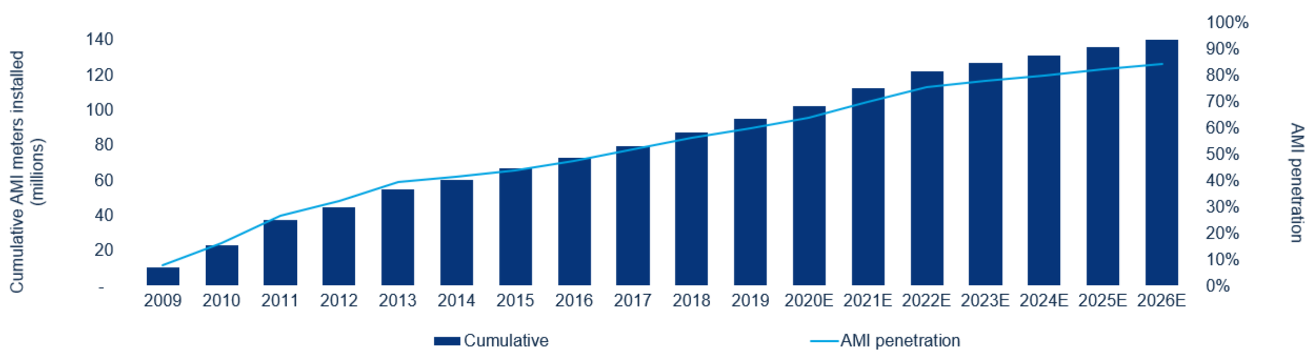
[27] Wood Mackenzie, *AMI Global Forecast 2021-2026*, https://www.woodmac.com/reports/power-markets-ami-global-forecast-2021-2026-475316 (March 11, 2021).

Figure 2.1: Residential Smart Meter Deployment by State, 2021



Institute for Electric Innovation (IEI) image depicting 2021 U.S. Energy Information Administration EIA-861 source data

Figure 2.2: Cumulative AMI meters installed in the U.S. and total market penetration*



*The annual percentage of AMI penetration in the U.S. is determined by cumulative AMI meters installed divided by the total amount of meters in the U.S. as of the end of 2019, multiplied by a percentage equal to the average growth in population expected by the U.S. Census Bureau between 2020 and 2026.

These statistics are forecasting that nearly 4 out of 5 homes in the US are estimated to have advanced meters in 2022, Rhode Island Energy peers generally have received approval and already have or are in the process of taking action to replace their legacy meters to pursue the cost savings and benefits opportunities created by the advanced technology. This proposal, if approved, would provide the same opportunity for Rhode Island Energy electric customers.

2.2 Current State of Rhode Island Energy Metering

Rhode Island Energy currently provides electric service to approximately 500,000 active electric customers across 38 cities and towns in Rhode Island.[28] The existing electric meter fleet largely consists of electromechanical meters retrofitted with an encoder receiver transmitter ("ERT") that provides AMR functionality, as well as solid-state electric AMR meters with integrated drive-by communication capability. The design life of the electromechanical meters is 30 years, while the ERTs and solid- state meters have design lives of approximately 20 years. The Company, while under National Grid ownership, retrofitted the electromechanical meters with ERTs beginning in 2000 and began installing solid-state electric meters in 2003.

Rhode Island Energy currently uses AMR drive-by technology throughout its service territory to read 99% of its electric meters. The ERT communication modules on both the electromechanical and solid-state meters send a radio signal to a fleet of service vehicles as they drive by to collect monthly reads. Rhode Island Energy's AMR technologies for electric customers are depicted in Figure 2.3.

Figure 2.3: Currently Deployed AMR Meter Types

Solid State AMR Meter

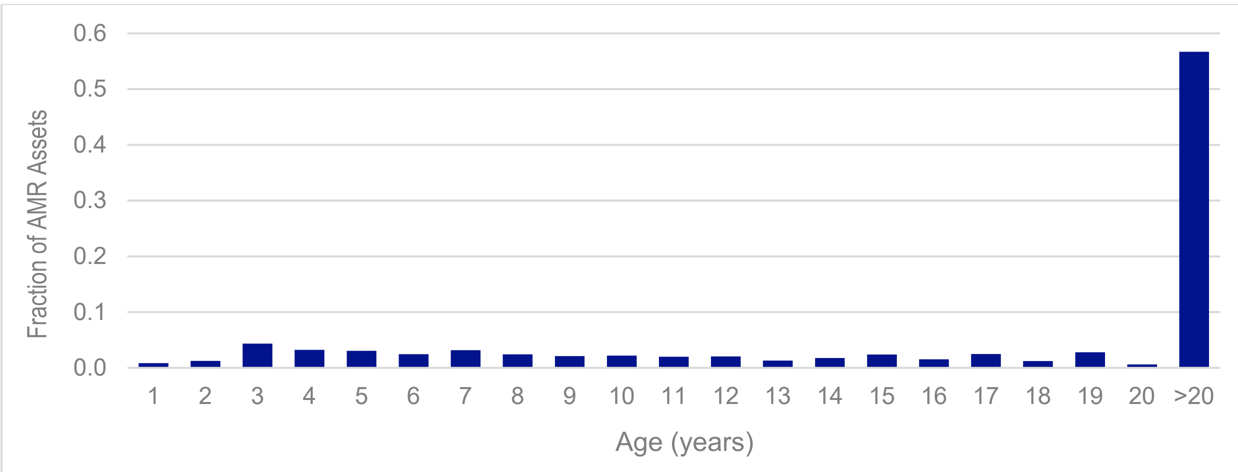
Electromechanical AMR Meter

This AMF Business Case is focused on replacing the electric AMR with AMF where approximately 60 percent of the Rhode Island Energy electric ERT and solid-state AMR assets

[28] Customers served by area is provided on Rhode Island Energy's web site: https://outagemap.rienergy.com/reports/50b6d221-6023-4b03-8255-656506b60825?c=Rhode%20Island&o=option-03254aee-1ae7-4d37-a19b-2b37fb24cba6.

currently in the field will reach the end of their estimated 20-year design life during by the end of calendar year 2024. Figure 2.4 provides the age distribution of the electric AMR assets.

Figure 2.4: Current Age of Electric AMR Assets



*Meter data based upon information provided in May 2022.

2.3 PPL Has Experience Implementing Features of the Next Generation Metering Technology

The five features of a metering solution that PPL believes are important to Rhode Island's future include:

- A metering system capable of capturing 15-minute usage and voltage data
- Communication infrastructure that includes a 2-way low latency network with the ability to read meters remotely and in real time.
- Because the new meters will result in significantly more information than what is received and processed today, systems development and integration to maintain the information received, offer functionality and provide the data to customers in a timely manner.
- Infrastructure providing the ability to interact with customers and be capable of interacting with devices within the home, so that customers can respond to critical pricing changes.

- Infrastructure that includes the ability to remotely disconnect electric service when a customer is moving out of a premise or remotely connect electric service when a customer is moving into a premise.

These features are available in AMF technology which represents the next-generation metering technology that can capture and transmit electric meter data back to the utility at 15-minute intervals through an IP-based RF mesh routing communications network. Granular 15-minute interval data is essential to transitioning operations for increased complexity to provide grid operators with increased visibility, short-term analysis, and longer-range planning, as well as to support increased DER penetration, dynamic rate offerings, such as TVR, enhanced customer education, and demand response ("DR") capabilities. A few examples of how Rhode Island Energy can use the granular 15-minute interval data to improve operations include understanding and following load curve and power flow changes, becoming aware of voltage violations, understanding hidden load that must be served during a distribution switching routine and having the ability to implement dynamic pricing and assess changes in usage trends.

These next generation meter technology features are not available with a one-for-one replacement of aging AMR metering infrastructure. Rather, features of the next generation meter technology provide new capabilities and functionality for operating, managing, and controlling the grid that are needed to transition, and enable integration of customer-owned resources, all of which is discussed in this Business Case. In short, the new technology replaces the aging electric meters <u>and</u> can provide functionality needed to achieve the State's Climate Mandates. It also will make the electric system more reliable by enhancing grid operations and outage management and provide information for electric grid modernization to better support resource planning as well as integrate distributed energy resources. And it will satisfy evolving customer expectations surrounding energy-saving technologies by providing detailed energy usage information and offering customers more support in determining how to control their energy usage. Moreover, it will allow Rhode Island Energy to connect or disconnect service more quickly for better customer service and enhance customer convenience and safety by reducing the need for in-person services.

Although new metering technology offers broad benefits and enables a new vision for electricity delivery, it usually takes years to deploy and integrate it with legacy back-office systems to fully realize those benefits. Here, however, PPL already has successfully deployed smart meters with many of these features. Rhode Island Energy customers will benefit from PPL's subject matter expertise, business processes, system integration experience, and lessons learned. More specifically, this includes: (a) selection of features and installation of the meters themselves; (b) the development and operation of back-office systems and operations processes that use metered data in both billing and system planning and operations; and (c) the design and installation of communication network capabilities to utilize the AMF metering system on the network for the benefit of consumers and the distribution system. PPL already put in several years of rigorous work understanding the data integration, operating platform, database management, troubleshooting, network design, and numerous other challenges and issues necessary to successfully utilize the AMF platform. Consequently, Rhode Island Energy can leverage all that work and need not repeat much if it when it performs its implementation and integration.

2.4 PPL Insights – AMF Meter Design and Implementation

Modernizing a complex electric grid system is not just a procurement exercise; it requires careful planning, product selection, rollout and installation, and operation. PPL plans to add value to its Rhode Island customers through its scale and demonstrated expertise in the selection and cost-effective deployment of a safe and secure AMF network. Rhode Island Energy customers will be the beneficiary of countless lessons learned that PPL has acquired by designing and implementing new AMF technology. Additionally, PPL has developed active strategic partnerships to co-develop AMF and GMP functionality, which Rhode Island Energy can leverage significantly, and which will be useful with respect to pricing and deployment logistics.

Similarly, PPL has already performed the analysis of alternative AMF meter models and features; acquired new AMF meters through a competitive bidding process; and installed more than 1.45 million AMF meters across 10,000 square miles. As a result, PPL has developed significant in-house subject matter expertise in all areas of AMF meter design, procurement, installation, and construction, along with the critical aspect of customer engagement. This has been extremely useful to plan the AMF as an enabling platform and valuable in identifying and road mapping the deployment of meter features that add value to customers, such as Last Gasp alerts which help identify outages and lead to quicker service resolution times, and remote connect and disconnect features which enable remote service functions to simplify customer service changes.

2.5 PPL Insights – Back-Office Systems Deployment and Integration

PPL has researched, identified, designed, implemented, and integrated the necessary and critical back-office systems and infrastructure in its other jurisdictions to maximize the benefits of AMF meters for its customers and stakeholders. This has resulted in functionality that provides a wide range of benefits improving safety, reliability, cost, and ultimately customer satisfaction. Examples of the major platforms that have been deployed and integrated include Customer Information System, Billing/Settlements Systems, Advanced Distribution Management System (“ADMS”), Distributed Energy Resource Management System (“DERMS”), Outage Management System (“OMS”), Data Analytics, and others.

These PPL platforms, systems, and expertise will be available to Rhode Island Energy – greatly improving the efficiency of implementation and providing value to Rhode Island consumers with the planned and purposeful rollout of AMF technology

2.6 PPL Insights – Communication Network Design/Implementation

PPL's demonstrated experience designing and building a secure communication network necessary to provide capability to operate AMF in the near term will enable the electric grid transformation to operate safely, reliably, and cost-effectively now and into the future when there is a significant penetration of the clean energy sources. For example, PPL has experience with backhaul design, selection of communication platforms, and specifications of secure communication requirements for large, full-scale AMF deployments. PPL has learned through experience that providing a hardened, secure, and sufficiently redundant network with capability and bandwidth for present and anticipated needs is important for reliability given externality and market condition uncertainty. Preliminary assessments of the Rhode Island Energy fixed communication network have contemplated the long-term requirements to provide network functionality and resiliency upfront, which is advantageous over the long-term. The Company will be able to leverage PPL network lessons that have been acquired over time resulting in established design standards that required system performance during the AMF communication design and implementation in Rhode Island. Because of the PPL network insights, the Rhode Island Energy communication network will be more robust than the National Grid design assumptions, mitigating the risk that there would be a need subsequently to add significant communication capability to deliver the expected functionality.

2.7 PPL Insights – People, Process, and Tools

PPL brings significant subject matter expertise, defined business processes, and systems from prior AMF deployment activity that will be advantageous to all aspects of planning, procurement, designing, managing, implementing, and operating an AMF program in Rhode Island, such as:

- Operations and Control: Operating and maintaining a 24/7 operations center to monitor the system and defend against cyber threats. PPL's existing platform has been tested extensively and designed based on cybersecurity considerations, which Rhode Island Energy will benefit from.

- Leveraging PPL Platforms: PPL has existing IT technology platforms such as ADMS, DERMS, Transmission Management System ("TMS"), Supervisory Control and Data Acquisition ("SCADA"), and modeling and control operations for the entire PPL transmission and distribution grid. These various IT technology platforms already are interconnected to PPL's GIS model and fully integrated with meter information. PPL can import Rhode Island Energy data and thereby leverage many of these existing systems and integration efforts to rapidly bring operational capability and cost benefits to Rhode Island Energy customers.

- Meter Information Processing: This function includes back-end processing of meter data for downstream functions that include billing, proactive outage management, retail settlement, load analysis, customer data presentment, and analytics. Rhode Island Energy will utilize the code base of PPL's CIS and Billing system to rapidly optimize the back-end processing functions for AMF deployment.

- Customer Experience Strategy: This function includes strategies and systems such as customer data presentment tools and data analytics to provide world-class customer service. Much of these benefits are found on the Customer Portals in PA and KY and offer PPL insight into which are most used and found beneficial to customers.

- Advanced Grid Integration: This function includes meter data analytics and integration with the distribution operational systems to support operational efficiencies, grid modernization, power quality improvements, planning, hosting capacity, and asset management optimization. Having implemented these functions previously, PPL can accelerate Rhode Island Energy's adoption of these improvements.

2.8 PPL Insights – Distributed Energy Resources (DER) Monitor and Management

Many utilities, including Rhode Island Energy, have experienced operations and planning challenges as DER penetration becomes increasingly significant. These challenges include, but are not limited to, voltage swings, masked or hidden load, limited DER hosting capacity, planning uncertainties, and protection/operational challenges with two-way power flow. In response to these challenges, the Institute of Electrical and Electronics Engineers ("IEEE") revised Standard 1547 in 2018 ("IEEE 1547-2018"), which set forth requirements for smart inverters that can help support the distribution system. When these smart inverters are coupled with DER management devices, electric utilities can monitor and manage DERs interconnected with their distribution systems.

On May 24, 2019, PPL Electric filed a Petition with the Pennsylvania Commission for permission to require smart inverters that meet the new IEEE and Underwriters Laboratories ("UL") standards to install DER management devices in conjunction with new DERs interconnected to its distribution system. The Pennsylvania Commission permitted the Company to conduct a pilot to test and evaluate the costs and benefits of monitoring and managing DERs that meet IEEE 1547 interconnection standards. The industry leading multi-year pilot, which launched January 2021, uses control groups to compare non-managed, locally managed, and actively managed DER methodology as specified in the DER Management Plan. AMF enables monitoring and management of DER by providing useful voltage data and a communication network to monitor and manage smart DER inverter devices.[29] The anticipated active management benefits are to improve customer power quality, increase system hosting capacity, and provide remote DER operability for items such as Volt/VAR grid support, ride-through setting management, and emergency shut-off. The AMF system design implications as it relates to DER management can provide helpful insight for achieving Rhode Island's clean energy future.

2.9 Summary of Benefits From PPL Experience

Rhode Island Energy customers will benefit from PPL's prior work and experience developing and deploying AMF and the associated business processes, operations, and IT platforms, as highlighted in the following examples:

- *AMF Implementation Cost Efficiencies:* Rhode Island Energy will leverage PPL's established processes, procedures, standards, system architectures, and configurations from Pennsylvania and Kentucky to implement AMF in Rhode Island. For example, the Annual Report that PPL submitted to the Pennsylvania Commission in 2020 is included in Attachment B. This can be modified to meet the needs in Rhode Island. Modification of an existing report which is much easier and faster than creating a report in its entirety. There are many materials and processes that can be repurposed to save Rhode Island Energy time and expense.

- *AMF Functionality Efficiencies:* Rhode Island Energy will be able to implement AMF functionality such as remote connect/disconnect switch, pro-active outage management, and meter alerts with greater efficiency based on its established processes, experiences, and learnings in PA.

- *AMF Operational Efficiencies:* Rhode Island Energy will capitalize on established business processes and experience gained in PA for staffing synergies. This includes leveraging its existing Advanced Metering Operations Team to manage deployment and operate AMF in Rhode Island.

- *AMF Shared Network Services*: PPL will use its existing IT, communications engineering, and network personnel across PPL jurisdictions, including Rhode Island, reducing redundancy of resources.

- *AMF Analytics:* Rhode Island Energy will use existing PPL analytics solutions, including voltage analysis, revenue protection, preventive maintenance of assets (i.e., meters,

[29] Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan, Docket No. P-2019-3010128, https://www.puc.pa.gov/pcdocs/1629570.pdf (July 30, 2019).

transformers), and prediction of transformer failures before they fail. AMF information and analytics has improved the availability and accuracy of load flow models, improved forecasting accuracy, been used to optimize maintenance plans, and provides insight for better voltage management. These are a few examples of how data analytics using information from AMF can improve the business now and into the future. A more detailed list of business benefits that PPL has realized in PA by incorporating and analyzing 15-minute interval data from AMF is provided in Attachment B.

- *AMF Best Practice - Pre-Sweeps*: Rhode Island Energy will include pre-sweeps as part of its AMF implementation plan to identify and mitigate potential issues, thereby making meter exchanges more efficient. The pre-sweep is an assessment of the meter location at the customer's premise prior to the actual meter exchange, which provides necessary information to identify potential safety issues and barriers to physical meter exchanges that improve safety and decrease overall deployment costs by enhancing meter exchange efficiency. PPL learned the value of pre-sweeps from its implementation of AMF in other jurisdictions.

- *AMF Best Practice – Meter Base Repairs*: Rhode Island Energy will include necessary meter base repairs at their cost as part of its AMF plan. Meter bases typically are the responsibility of the customer, however, in this Business Case, Rhode Island Energy has included them to ensure the safe, efficient, and cost-effective exchange of meters based upon PPL lessons learned.

Rhode Island Energy customers also will benefit from PPL's experience in Pennsylvania incorporating the 15-minute interval usage and voltage data into a number of core business functions, which PPL can leverage to deliver a number of benefits and process improvements, examples of which are set forth in Attachment B, including:

- Development of Time of Use and Real Time pricing rates;

- Development of other complex billing rates that require interval data to determine coincidental peak demand;

- Faster and more accurate investigation and resolution of customer billing inquiries;

- Improved settlement processes with the regional grid operator through the ability to create aggregations for settlement based on actual usage rather than estimates. Since using interval data for settlement, PPL's Pennsylvania utility has realized a reduction in the calculated Unaccounted for Energy ("UFE") which is a comparison between the total load from the ISO compared to the aggregation of all the Meter Data Management System ("MDMS") data;

- Improved coordination with suppliers resulting from their portal access to view their customers' actual interval usage – allowing suppliers improve services by billing using interval data and reduced the number of data requests to the utility;

- Operational benefits resulting from reliability engineers' use of the interval voltage data to identify problem areas and quickly pinpoint where improvements need to be made and the Advanced Metering Operations use of interval voltage data to help analyze meter anomalies, which both reduces truck rolls (as problems can be solved from the office) and identifies meters to be replaced before they fail.

By utilizing PPL's AMF experience and leveraging its back-office systems, the benefits associated with the Rhode Island Energy's proposed AMF investment are anticipated to be accelerated as compared to National Grid's assumptions in its AMF Updated Business Case submitted to the PUC in January 2021, as explained in Attachment C.

Section 3

SECTION 3: EVALUATION OF SOLUTIONS AND ENABLED FUNCTIONALITIES

This Section describes the limitations of the current AMR system and assesses alternative metering solutions and corresponding functional characteristics needed to provide flexibility and adaptability to meet future evolving needs. The new customer, operations and environmental functionalities that can be enabled with a full-scale AMF implementation are described along with the approach that Rhode Island Energy will use for technology review and selection.

This Section identifies limitations of the existing metering infrastructure as it relates to present and future needs and maps enhanced metering functionalities that would be available with various AMF solutions. Also included is a detailed description of how these functionalities will enable the safe and reliable operation of Rhode Island Energy's delivery system and how AMF is a fundamental building block for achieving the State's climate goals and mandates. To develop this section, Rhode Island Energy used the comprehensive work completed by the Company when it was under National Grid ownership, PPL lessons learned from its AMF experience in Pennsylvania and Kentucky, information from electric operations and billing/metering personnel with experience on the Rhode Island Energy system to understand the challenges facing grid operations with the growing penetration of DERs, intermittent supply resources, EV charging, and the need for innovative rate structures (i.e., TVR).

3.1 Limitations of Existing AMR to Meet Future AMF Requirements

The critical challenges facing the Rhode Island Energy distribution system today are the emergence of DERs such as roof-top solar facilities and Electric Vehicles ("EVs"). These distributed generation resources have introduced disruptive bi-directional flows across electrical circuits serving customers, as well as concentrated demands at peak periods as EV batteries are charged simultaneously. From an engineering perspective, the chaotic nature of bi-directional flows across the low-voltage distribution system compromises the effectiveness of protection and control schemes and undermines the stability of the system due to undulating voltage levels caused by the unpredictable and intermittent nature of solar generation. If not managed correctly, the effect of DERs on the system will not only cause premature failure of system components such as transformers and present safety risks but will also increase operating costs and degrade reliability as unplanned outages increase.

The need to obtain near real-time visibility and awareness of system conditions can be achieved in multiple ways, such as using information from the AMF system in conjunction with GMP technologies. AMF can contribute to needed continuous situational awareness by providing visibility with granular[30] information coming from each customer meter location every 15

[30] Granular data is detailed data, or the lowest level that data in a target set. The granularity of AMF data is provided for through the availability of 15-minute interval, time sequenced data measurements. This level of

minutes so dynamic system conditions can be monitored and understood at any place or level on the distribution system. Coupling the visibility provided by AMF interval data with grid modernization investments, provides Rhode Island Energy with the wherewithal to accommodate increased DER penetration necessary to achieve the Climate Mandates, while maintaining safety and reliability. This wherewithal is afforded because the unpredictable nature of the system can be modeled to understand impacts on power flow, operational procedures can be adjusted, and remote actions can be taken to course correct voltage violations and change protection schemes.

Today, the distribution operators of the electric distribution system in Rhode Island have little situational awareness of the state of the system on either a granular or locational basis. AMR meters in Rhode Island are read using the AMR drive-by technology which captures a read that is downloaded to a system for billing every month, providing no real-time visibility. With the growing penetration of DERs in Rhode Island (i.e., solar PV, batteries, EV charging, and others), continuing to operate in this manner can undermine the safety and reliability of the system, both with respect to the public and utility operating employees.

To safely and reliably operate the electric distribution system in this evolving environment, Rhode Island Energy needs technology that provides new capabilities and functionality for operating, managing, and controlling the grid, and even enables integration of customer-owned resources. These factors are critical in determining how the Company should invest to replace its existing AMR meters as they reach the end of their design life, and a one-for-one replacement of aging equipment is not necessarily the most effective option. Rather, the replacement investment can lay the foundation for a future of electricity delivery by enabling capabilities that provide additional functionality. An opportunity to satisfy the following broad set of objectives is presented with an investment in next-generation meter technology:

- Address end-of-life AMR meters
- Provide an enhanced customer engagement platform
- Enable the achievement of the Climate Mandates
- Provide shorter/near real-time meter intervals and greater data storage
- Enable DER monitoring and management
- Enable the implementation of FERC Order 2222

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measurement is much finer than historically offered making richness of information available for improved analytics and greater operational visibility.

- Reduce utility O&M expenses
- Mitigate safety and reliability issues
- Enable over-the-air meter firmware upgrades
- Provide increased visibility to the system operator and the customer with near real-time data.

3.2 Evaluating Alternative Metering Solutions

Rhode Island Energy considered the analysis the Company performed while under National Grid ownership that compared metering technology solutions both from a customer and grid-facing perspective. That analysis assessed the relative merits and cost-effectiveness of a variety of customer, grid, and meter-level technology solutions. It also identified and compared metering technology solutions and complementary customer and grid technologies to determine which options met the capability requirements of a modernized grid. Rhode Island Energy agrees with that analysis. The customer- and grid-facing solutions that were evaluated are summarized below along with a chart demonstrating the degree of functionality that each solution supports.

Current AMR meters – The AMR meters currently installed in Rhode Island Energy's service territory provide the ability to "drive-by" the meters to collect readings rather than having to walk up to the meter to read it, but they cannot provide energy usage data with the granularity and frequency needed for delivering messages through the Customer Portal such as personalized advice for EE and DR. As a result, AMR does not retrieve metering data at a frequency needed to provide visibility to operate the electric distribution system safely and reliably now or in the future or deliver information at a rate that enables customers to make informed energy choices. Even if Rhode Island Energy were to augment the system with grid-edge sensors, the AMR meters still cannot detect voltage anomalies or pinpoint system outages. Continued investment in the legacy AMR system is not cost-effective or practical. AMR will not be capable of providing functionality to effectively, safely, and reliably operate the changing energy grid necessary to deliver Rhode Island's renewable energy and greenhouse gas emissions reductions mandate because they do not provide operators with the visibility that will be needed as the system complexity increases from distributed energy resources and demand changes from electric vehicle charging. Additionally, as the technology continues to age, it will become obsolete, will not scale, and will be more difficult to service and maintain.

If Rhode Island Energy was to continue to invest in AMR meters, the manufacturer will eventually stop providing AMR parts and adequately servicing a legacy solution that is outdated. Re-investing in the current AMR system is a costly path because it would be an unworkable solution to meet future needs that would eventually strand the AMR investment when it is replaced with a future proofed AMF solution.

Enhanced AMR meters – Enhanced AMR Meters include a "triple communication" module on each AMR meter set that could support the limited implementation of time-varying demand rates. This option, however, suffers from severe functional limitations. It would change the communication module on the existing AMR meter, which would result in a meter than can measure no more than three units of energy measurements. For example, three units of measurement could be peak, off-peak and total energy usage. The Company would need to re-program the AMR meters whenever the rates are approved or changed. This option is significantly more expensive than an AMF meter after considering the added cost of re-programming. As a result, enhanced AMR meters are cost prohibitive with limited functionality, and not a reasonable option.

End-User Solutions – End-user solutions include devices that customers can procure and install in their home that track and identify the power used by their appliances and devices. The end-user solutions provide some of the customer functionality provided by AMF meters such as load disaggregation, but they do not provide any of the grid-facing functionality or revenue-grade billing determinants and they do not meet ANSI energy measurement standards. A key limitation of these solutions is the absence of interconnectivity and integration with the Company's installed meter or with the Customer Portal, resulting in isolated, standalone third-party solutions that do not provide the increased visibility needed to manage the transforming electric grid. Also, these solutions often are more expensive than the AMF meters. Accordingly, reliance on end-user solutions alone is not a reasonable option.

Transformer and Feeder Sensors – Across the distribution system, sensors are strategically placed to support a variety of grid modernization functions while also collecting granular, time-aligned voltage and current data. This provides a series of grid-facing benefits such as better voltage regulation and outage notifications; however, visibility is only available at sensor locations such as feeder mid-**points** across the system. Therefore, this is an inferior solution as compared to the grid-edge sensing capabilities of AMF meters. In addition, these sensors will not address any of the required customer-facing functionalities needed in the future. Accordingly, the use of transformer and feeder sensors is not a reasonable option.

Pole-Top Readers – Pole-top reader technology leverages a combination of standard and enhanced AMR technology, replacing drive-by meter reading vehicles with remote AMR meter reading radios. A pole-top reader can support enhanced meter reading frequency from AMR devices, but it remains limited to meter register readings and does not provide the same level of functionality and data delivery as AMF. Accordingly, the use of pole-top readers is not a reasonable option.

Targeted AMF Deployment – A targeted deployment of cellular-based AMF meters supports some enhanced customer benefits. The Company leverages this cellular solution today to support a subset of Rhode Island Energy's G32 customers (less than 300 customers). To expand its reach, the Company would need to enhance the cellular network to support additional meter end points. This type of targeted AMF deployment would have higher O&M costs and, although it would have the near real-time visibility of the status of the distribution system, that visibility would be available only at the targeted locations. Accordingly, a targeted AMF deployment is not a reasonable option.

Full AMF Deployment – Full-scale AMF deployment will integrate with customer and billing platforms, as well as the Customer Portal, to provide energy usage data access, insights, and service offerings so customers can be empowered to take more active control of their energy destiny and responsibility for their environmental footprint. The AMF platform also provides ubiquitous sensing and remote connect/disconnect capabilities at the edge of the distribution system that supports grid modernization functionalities such as locational awareness/GPS, and granular, time-aligned voltage and current data for electric meters. These capabilities will allow the Company to operate more safely and reliably by being able to better regulate voltages on the system consistent with tariff requirements, enhance outage restorations, improve DER control/integration, reduce energy consumption through voltage optimization/conservation voltage reduction ("VVO/CVR"), and keep workers and customers safe by remotely disconnecting when needed in times of emergency. AMF technology is the only solution offering two-way communication capabilities that can enable dynamic TVR remote configurations useful to regularly pass along pricing and energy insights to customers. AMF also brings the added value of remote meter investigations, remote connections and disconnections, outage management enhancements, and the additional capability of delivering "over-the-air" updates to deploy new features and enhanced cybersecurity software patches remotely as they become available.

Figure 3.1 depicts a comparison of the functionalities of the solution options described above, both from a customer-facing and a grid-facing perspective. While all the options provide some functionalities, only the full deployment of AMF meters provides all the functionality needed as Rhode Island continues to move to a clean energy future.

Figure 3.1: Functionality Assessment of Metering Solutions and Customer and Grid Technologies

	AMF Functionality/Use Case	Complete Metering Solutions				Complementary Customer and Grid Technologies		
		Current AMR	Targeted Enhanced AMR (for opt-in TVR)	Targeted AMF*	Full AMF	End User Solutions**	Transformer-Level Sensor	Pole-Top Reader***
Customer-facing	CEMP – Near Real Time Customer Data Access	○	○	●	●	●	○	○
	CEMP – Customer Energy Insights	◑	◑	●	●	◑	○	◑
	CEMP – Bill Alerts	○	○	●	●	◑	○	◑
	CEMP – Load Disaggregation	○	○	●	●	●	○	○
	CEMP – Green Button Connect	○	○	●	●	○	○	◔
	Integration w/ In-Home Technologies	○	○	●	●	●	○	○
	Time Varying Rates - Customer & DER	○	◔	●	●	○	○	○
	Remote Interval Meter Reading	○	○	●	●	○	○	○
	Remote Meter Configuration	○	○	●	●	○	○	○
	Remote Meter Investigation	○	○	●	●	○	○	○
	Remote Electric Connect and Disconnect	○	○	●	●	○	○	○
	Theft Detection	◔	◔	◕	●	○	○	◔
Grid-facing	Voltage Measurement – Voltage Conservation	○	○	◔	●	○	◑	○
	Outage Detection – Automated Notification	○	○	◔	●	○	◑	◔
	Time Varying Rates – Load Shift	○	○	◕	●	○	○	◔
	Load & Voltage Data – Situational Awareness/Forecasting	○	○	◔	●	○	◑	◔

*Harvey Balls for Targeted AMF indicate functionality enabled for customers who adopt AMF meters, not theentire population

**Includes combinations of high-resolution home sensors (e.g., Sense) with in-home technology packages (e.g.,Nest, Alexa, etc.) and no integration with CEMP or company systems.

***Assumes integration with utility platform services (e.g., billing)

3.3 Recommended Full-Scale AMF Scope

As reflected in National Grid's Updated AMF Business Case that was filed with the PUC in early 2021, and consistent with PPL's AMF findings in Pennsylvania and Kentucky, Rhode Island Energy concludes that a full-scale AMF deployment represents the most cost-effective solution. This full-scale AMF deployment not only provides advanced meters to all customers in Rhode Island, but it also provides an integrated communications network, back-office and IT enhancements and the programmatic support to enable customers to use their new information to save energy and help reduce the system peak. The broad deployment of AMF supports maximum functionality and adaptability of the intelligent computer platform residing within each metering device, along with peer-to-peer communication and data analytics.

The full scale AMF technical solution includes the following four advanced metering elements: 1) an integrated IP-based RF mesh peer-to-peer network consisting of AMF electric meters capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications; 2) a two-way communications network and related IT infrastructure for transmitting the data and control signals utilizing mesh communications technology; 3) an integrated Head End System ("HES"), MDMS, IT platform, and cybersecurity protocols to securely and efficiently collect, validate, store and manage the meter data; and 4) customer systems including billing and the Customer Portal to provide energy usage data access, insights, and service offerings that enable customer energy management.

The full-scale AMF solution would consist of electronic meters equipped with wireless communication technology that will use a secure, fixed radio frequency ("RF") communication network to send 15-minute interval data, status and alarms, such as temperature and voltage, to Rhode Island Energy. The system also is designed to anticipate that it will need to capture gas usage from gas meters every hour and transmit it every four hours (Section 4 describes Rhode Island Energy's plans for how Electric AMF will enable gas modernization) and communicate with DERs. Gateway and router devices that form the IP-based RF mesh communication system are located throughout the service territory to collect and transmit meter data to the Company. A series of computational systems validate and process the data to make it available for billing, retail settlement, and for the customers and other third parties who are authorized to access energy consumption data, energy insights, and service offerings. This full-scale Business Case assumes:

- 524,677 AMF electric meters that replace AMR metering technology. This represents the total meters minus 1% opt out and the 901 customers that have the MV-90 meter reading system for some Commercial and Industrial customers.

- 109 high-capacity gateways, 402 standard-capacity gateways, and 1,280 routers for the mesh communication system.

- Systems and software as described in Section 6.

This Business Case assumes that all the electric meters are converted to the AMF solution during the deployment period except for those that Opt-Out from receiving an AMF meter and the 901 electric meters that use the MV-90 system. Of the MV-90 population that is excluded, approximately 100 large retail customers have interval meters that are currently read daily by the MV-90 system. After the initial Deployment, as many of the MV-90 meters as practical will be converted to the AMF as opportunities present themselves for Rhode Island Energy to offer functionality described in this Business Case.

Rhode Island Energy's decision to propose a full-scale AMF deployment in this Business Case will enable a breadth of enhanced functionalities and is the only fit-for-purpose solution for meeting the objectives and capabilities for a modernized grid. The enhanced functionalities enabled by AMF meters as compared to the limited capabilities of the current AMR meters are a key for Rhode Island Energy to having the capability to enable Rhode Island's Climate

Mandates, provide customers with timely information to make more informed energy choices, and to have the visibility to operate more reliably as the system becomes increasingly complex. Many of the new functionalities that can be offered by a full-scale AMF are described below and will provide significant benefits.

3.4 Enhanced Functionalities Available From Full-Scale AMF Solution

Detailed descriptions of the enhancements that AMF unleashes is provided below for customers, operations, and the environment.

3.4.1 Enhanced Customer Functionality

The various enhanced functionalities that customers will experience from a full-scale AMF deployment are enumerated below:

- *Enhanced Energy Management*: Enable customers to view energy consumed and energy produced to take control of their energy usage. This will result in more effective EE, conservation, and DR programs, along with access to smart-home devices. AMF improves the efficacy of EE and DR programs by providing more granular data to customers (e.g., detailed billed energy use and near-real-time data).

- *Third-Party Programs and Offerings:* Animate the market for third parties to drive innovation and provide additional value to customers, while encouraging new customer offerings. With the implementation of FERC's Order 2222 which begins later this year, third parties will include aggregators who will group DERs and offer them as one into the ISO-NE market.

- *Customer Service Enhancements*: Notifications about changes to consumption patterns mid-month that give customers an opportunity to act before the end of the billing cycle, remote connect and disconnect for electric service, and enhanced outage management capabilities. AMF also enhances customer convenience and safety by eliminating the need for customers to provide access to indoor meters or submitting self-reads. AMF also provides for more convenient service activation and account transfers through remote meter service switching.

- *Enable Vehicle Electrification*: Customers can save Electric Vehicle charging costs by shifting charging load to off-peak times using AMF-enabled TVR. This will ultimately defer or avoid transmission and distribution ("T&D") upgrades that would have been needed and enables the achievement of environmental goals.

- *More Visibility to Usage*: PPL has experienced higher customer satisfaction with Call Center interaction because customers who are making the inquiry as well as the

Contact Center Agents have comprehensive energy usage data and analysis available to them.

- *Customer Outage Notification:* Reduction in outage notification time is estimated at 22 minutes per customer outage (using PPL historic information). This time savings is due to automatic notification features enabled by AMF Last Gasp technology that informs the Company of power outages in near real-time, largely eliminating and/or significantly reducing the need for customer-initiated phone calls to the Company.

3.4.2 Enhanced Operational Functionality

The various enhanced functionalities for operations that will be experienced from a full-scale AMF deployment are enumerated below:

- *Situational Awareness*: AMF, in combination with GMP investments, provides granular, near real-time values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder of the electric distribution system. This complete data set can be modeled directly resulting in more detailed and accurate load and DER forecasts for increased operational awareness so that operators can take preventative action when near term issues are identified that require operator actions (e.g., sectionalizing, selective curtailment, and others).

- *Load Shifting:* Reduce customer delivery costs by avoiding traditional distribution infrastructure investments due to the ability to shift load using AMF-enabled TVR and more effective customer load management programs. This is further described in Section 13.

- *Voltage Management and Conservation*: Meters produce accurate voltage readings at the customer service delivery points enabling PPL to provide granular and macro system voltage level management. Visibility of voltage provided by the meters enhances the ability for voltage conservation to reduce demand and energy use through conservation voltage reduction (“CVR”). The advanced Volt-VAR Optimization (“VVO”) control schemes coordinate multiple voltage regulating devices of an electric circuit to achieve optimal CVR performance. Based on actual case studies, an incremental .5% reduction in energy usage is expected to be achieved and is being attributed to the AMF Business Case by integrating granular voltage data from AMF into the CVR/VVO control schemes. This is projected to increase with the future implementation of the GMP (FLISR, smart capacitors, LTCs, voltage regulators, etc.).

- *Automated Notification*: AMF meter outage information integration with the Company’s outage management system (“OMS”) and processes will improve customer communications and restoration operations following outages. AMF reports customer outages in near real-time, which provides system outage awareness and allows field personnel to restore power without relying solely on customer calls and substation monitoring. AMF can also verify that all meters have had service restored. Power on/off alerts from automated meters allow the detection of outages before a customer calls or when customers are not home. The Last Gasp and Power Up functionality improves service response and outage detection for more efficient crew dispatching and storm restoration management. Nested outages (e.g., residential service outages that may not be readily seen by operators in the Outage Management System because they are superseded by higher-level equipment outages at transformers and circuits) can also be better managed by pinging (remotely interrogating the status of power at meter locations from operations control centers) meters to identify false outage information and confirm their restoration.

- *Remote Connect/Disconnect*: AMF meters will enable remote connections and disconnections through remote service switching which is the capability to turn meters on and off to support changes in occupancy, reoccurring non-payment issues, and prepaid service offerings. Truck rolls to disconnect and reconnect meters when customers move-in or -out can most often be avoided because of the feature embedded in the meter to perform this function remotely. In addition, the hours to perform reconnects can extend outside of normal business hours because they can be done remotely for electric meters. These services previously would have required scheduling service appointments and waits of up to several days for service trucks to arrive. On-demand services are particularly valuable for seasonal or temporary residents who typically have variable schedules and need for assistance.

  Quicker connection and transfers of service have been shown to result in greater customer satisfaction. The remote connect and disconnect capability enables final, non-estimated move-in and move-out bills resulting in a reduction in special meter reads in the field. There is an improvement in safety for service technicians because they no longer need to physically disconnect the meter, thereby reducing the chance of an electric flash incident or confrontation by customers or their pets. The risks for customers and first responders are also mitigated during emergencies due to having expeditious shutoff capability. The remote service switch may be used to support firefighters and other first responders. This will enable them to address the emergency more quickly rather than waiting for utility crews to arrive and shut off the meter.

- *Reduced Field Investigations*: AMF provides alerts and alarms that allow for meter investigations and resolutions to take place remotely without sending a field technician to the premise to change the meter. Also, tamper alerts and usage profiles along with advanced analytics can be used to identify theft and take necessary action to reduce it.

- *Reduced Customer Inquiries*: AMF provides near real-time customer information. This reduces the work associated with customer inquiries to answer service questions. Customers with concerns about high bills or unusual consumption patterns can access or request bill information on demand using the Customer Portal or by contacting a customer service representative. With AMF there are fewer estimated bills and customer complaints regarding service.

- *Reduced Meter Failures*: Aging meter failures will be reduced because the old meters will be replaced with new meters. The new AMF meters will provide issue detection and mitigation for:

    1) Display corrupted
    2) Volatile memory error
    3) High-temperature alerts
    4) Voltage alarms
    5) Outage/restoration

- *Improved System Asset Identification and Connectivity*: AMF meters will provide electric operators with critical situational awareness data and functionality capable of improving safety and reliability. When meters are correctly associated with the facilities that serve them, the accuracy of the network model is improved resulting in benefits from better customer service, planning accuracy and operational efficiencies. Improved circuit model accuracy results in better analysis and enhanced interoperability with other systems. Examples include:

    - Electric meter data is provided to the DERMS/ADMS for transformer load studies and voltage optimization. Improved customer outage modeling and customer load information reduces design times from knowing the information on the secondary side of transformers without site visits, and the internal data provides enhanced information for improved transformer sizing.

    - The AMF data is also used as an input to the Fault Location Isolation and Service Restoration System ("FLISR") that sectionalizes the distribution system in response to an outage and facilitates a more efficient restoration response. Some of the other Grid Modernization functionality that the meters could enable include reducing maintenance expense when voltage readings signify a potential transformer failure, reduced line loss from better voltage management, reduced energy usage due to CVR and understanding watt/var usage on large industrial customers or large solar customers to improve power flow analysis.

- AMF meters can also enable DER monitoring and management which is a critical tool to effectively manage the high volume of Solar PV and other DER devices on the distribution system.

- *Outage Mapping and Tracking*: Rather than depending on phone calls that come from customers when they experience an outage, PPL plans to integrate the data from the AMF meters directly into the GIS, thereby providing the operators visual tracking of deteriorating conditions on the system (e.g., low or high voltage, critical flow data, etc.). This will result in better customer service due to improved trouble shooting for outages, device identification, and dispatching to restore customers on a blue-sky day and during storm conditions.

- *Forecasting and Planning (near term, long term, and scenario planning)*: AMF meters will provide PPL with the granular data necessary to improve near-term and long-term forecasting and modeling. This complete data set can be modeled directly resulting in more detailed and accurate load and DER forecasts for increased operational awareness and planning future grid needs. With this capability, planners can more easily identify “hidden load” and can better plan needed facility improvements that are required for upcoming seasons and for the longer term.

- *Demand-side Management (“DSM”)*: AMF meters further enhance DSM programs for customers because of the granular and locational nature of the data, and the increased frequency of data measurement.

3.4.3 Improved Environmental Conditions

The functionalities resulting from full AMF deployment will improve environmental conditions as described below:

- *Reduce Emissions*: By empowering customers with AMF data outputs, customers can reduce energy consumption and better manage energy usage thereby reducing emissions.

- *Enable Clean Energy*: By having knowledge of actual DER output, DER hosting capacity can be increased compared to using nameplate capacity assumptions, thereby enabling additional DER and energy storage interconnections. This also reduces carbon emissions.

- *Reduced Truck Rolls*: Emissions are decreased due to reduced truck rolls due to elimination of drive-by meter reading and due to having the capability to remotely disconnect meters, investigate meters, monitor temperature, detect tamper conditions, and having visibility of power status. Dispatching of trouble crews during storms and for system restoration will also be more efficient due to the granular information provided to the ADMS which is being populated with data from AMF meters.

- *Volt/Var Optimization and Conservation Voltage Reduction*: By having much more granular and frequent data on the system, operators can optimize volt/var and provide conservation voltage reduction when appropriate. These are estimated to save 0.5% of electricity use on the system, resulting in fewer GHG and NOx emissions and better Public Health.

3.5 Technology Review and Selection Process for AMF

Because all meter technologies are constantly being enhanced and improved, meter selection needs to strive for the best overall meter functionality to meet present and future business requirements. Based upon the functionality and the full-scale AMF scope discussed above, PPL is reviewing and evaluating available AMF meter features available through various technology offerings. PPL's experience implementing AMF meter systems in Pennsylvania and Kentucky provides significant insight into the meter, communications and IT/back-office needs. With these insights, PPL can better ensure the AMF system will produce required functionalities. The following stated goals of AMF meter deployment in Rhode Island will be used to establish functionality-based criteria that will guide the Rhode Island Energy AMF technology review and selection:

- Address end-of-life meter assets (AMR)
- Enhance customer engagement
- Contribute to the achievement of the Climate Mandates
- Provide data that enables the grid to be operated reliably and safely
- Enable DER management and leveraging value in energy markets
- Enhance cybersecurity protection with over-the-air firmware updates.

Section 4

SECTION 4: ELECTRIC AMF IS AN ENABLING PLATFORM

This Section describes how AMF provides a platform for functionality that is of strategic importance to achieving Rhode Island's renewable energy and greenhouse gas reduction mandates. GMP is a must-have to achieve a clean energy future. The GMP objectives and the fundamental role AMF plays as part of the integrated GMP by enabling and delivering both customer- and grid-facing functionalities are provided. The Section also discusses how AMF enables gas network modernization, DER integration, other end-point integration, transportation electrification and innovative rate structures, all of which support the Rhode Island vision and offer significant promise for future value streams. The Section concludes with preliminary plans future regulatory actions.

Section 4 is a unique Section in this Business Case because it discusses the importance of AMF as a platform to enable additional capabilities that are generally beyond the scope of this Business Case unless otherwise mentioned. AMF is an enabling platform. The content in this Section presents a vision of what is possible and how the AMF enabling platform can be built upon to add incremental value for Rhode Island. Any aspect discussed in this Section will require preparation, outreach, and further regulatory proceedings (as necessary).

4.1 AMF Enables Grid Modernization

The GMP will present a holistic and comprehensive view of how the capabilities of the grid will need to evolve over time. It will identify foundational building blocks and tools for a modern electric grid that is flexible and adaptable to the changing resource mix, agile in the face of more dynamic grid operations, and enables effective coordination between the wholesale market and distribution system operations. These investments will be an important part of readying the grid for fleets of EVs and greater deployment of energy storage. The GMP will expand capabilities in monitoring, sensing, communication, and control, which increase grid visibility, situational awareness, data collection, and the ability to respond to varying grid conditions and anomalies in real time. These capabilities simultaneously support de-carbonization, increased resiliency to extreme weather events and climate change, and enable greater DER market growth. Rhode Island Energy's GMP will be intended to provide a future distribution system capable of achieving the following objectives:

1. Providing customers more energy choices and information;

2. Maintaining and enhancing reliable, safe, secure, clean, and affordable energy to Rhode Island customers over the long term; and

3. Building a flexible grid to integrate more clean energy resources.

AMF is key to delivering capabilities defined in the Company's Grid Modernization Plan ("GMP"). The GMP functionalities and a description of how AMF enables them, being foundational[31] and enhancements, are provided below as evidence that AMF is a bedrock technology that is needed to achieve the GMP objectives. AMF provides capabilities that are building blocks to the GMP making AMF its prerequisite. AMF meters are both needed and enhance GMP investments by providing increased visibility into grid conditions that support distributed system planning functions, greater DER adoption, and the development of a more efficient, reliable and resilient energy network. Some of the GMP functionalities[32] are listed below with a brief description of how AMF investments enable them. The AMF capabilities that are being leveraged by the GMP to support various functionalities are noted in *italics*.

- ***Customer Information*:** AMF provides access to timely, granular energy usage information for all customer classes through three primary channels: (1) web and mobile devices via the Customer Portal; (2) data sharing using Green Button Connect ("GBC") that will be available on the Customer Portal; and (3) directly from the meter in real-time through a home-area-network ("HAN"). AMF also empowers customers to reduce their energy costs using enhanced insights (such as high-bill alerts) based on more granular, timely energy usage data available through the Customer Portal or through integration with the Home Area Network. *The foundational AMF capabilities being leveraged by GMP are Customer Portal, Green Button Connect, and integration with in-home technologies.*

- ***Advanced Pricing*:** AMF provides interval energy usage information required to support TVR and customer load management programs that can be used to shift energy consumption between time periods to reduce energy costs and/or alleviate location-specific constraints on the delivery system. This will ultimately enable efficient Smart EV Charging and battery storage for customers and the utility. *The foundational AMF capability being leveraged for GMP outcomes is interval energy usage data which can be coupled with time variable rate pricing mechanisms.*

- ***Remote Metering*:** AMF improves operational efficiency by enabling the Company to reduce O&M costs associated with AMR meter reading, meter investigations, and visits to connect and disconnect service. *The foundational AMF capabilities being leveraged for GMP outcomes are remote interval meter reading and the ability to remotely connect and disconnect electric service.*

- ***Observability (Monitoring & Sensing)*:** AMF provides granular and timely customer load data to deliver actionable information on the operating state and condition of the distribution grid and DER assets necessary for safe, secure, and reliable operation. AMF

31 "Foundational" means the GMP functionality would not be possible without AMF.

32 A full list of GMP functionalities was created using the DOE Modern Grid Initiative as guidance and are discussed in the GMP filing. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

information results in greater situational awareness that leads to improved operating and planning capability such as the anticipation of hidden load in switching schemes, for example. *The enhancing AMF capability being leveraged for GMP outcomes is load and voltage data which will be used as an input and integrated with GMP operational platforms.*

- ***Voltage Management*:** The Company expects to achieve an incremental 0.167% VVO/CVR-based reduction in peak demand by integrating granular AMF voltage data into the VVO control schemes. This data will provide better awareness of feeder voltages compared to only using voltage data from advanced field devices. *The enhanced AMF capability being leveraged for GMP outcomes is granular voltage data that is used as an input and integrated with GMP voltage control schemes.*

- ***Distribution Grid Control*:** Granular and timely customer load data from AMF supports more accurate load-flow calculations, enabling the system operator to better control power flows on the distribution system and optimize power output from renewable DERs (through ADMS to relieve or avoid thermal or voltage constraints rather than investing in traditional solutions (e.g., reconductoring, substation upgrades). *The enhanced AMF capability being leveraged for GMP outcomes is granular and timelier load and voltage data that is used as an input and integrated with GMP operational platforms.*

- ***Grid Optimization*:** AMF provides granular, 15-minute interval load data customer metering, which provides a step-change in available data for grid planning and operations. Analytics of the AMF interval data will significantly improve the load flow models used by distribution planners. Today, feeder-level data combined with generic load shape analysis is used to model feeder performance. AMF provides more granular, timely values that can be aligned with other systems, such as PPL's ADMS to create actual loading and voltage profiles at all points along a feeder. More detailed load and DER forecasts can be developed for planning and operational needs. *The AMF enabling capability being leveraged for GMP outcomes is granular and timelier load and voltage data that is used as an input and integrated with GMP operational platforms.*

- ***Reliability Management*:** AMF provides automatic outage notifications in the form of Last Gasp, alerting the Company to troubleshoot before receiving customer outage calls. Integrating this functionality with the Company's OMS (via PPL's ADMS) will reduce the time from initial outage to Company notification. In Pennsylvania, automatic notification has resulted in a 22-minute faster notification of customer outages on average. AMF also provides restoration notifications enabling the Company to verify whether power has been restored to all meters, reducing the need for crews to verify restoration (i.e., lights-on truck rolls) and alerting the Company if some meters are still out of power. In addition, AMF provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of the PPL ADMS. More accurate fault location improves operational efficiency through a reduction in field crew hours and vehicle miles traveled, and it improves the isolation and restoration capabilities of FLISR. *The enabling AMF capability being leveraged for GMP outcomes is automated outage notification and restoration notification that is used as an input and integrated with GMP operational platforms.*

- ***DER Monitor and Management*:** AMF deployment will enable DER Monitoring and Management to increase hosting capacity. AMF also supports DER optimization by providing the interval energy and voltage data at the customer level required for verification and settlement. AMF facilitates the exchange of information and/or control with all residential and small commercial (<25 kW) DER technologies through the build-out of Tier 3 FAN operational telecommunications. This communication infrastructure would not be available without AMF deployment. *The enhancing AMF capability being leveraged for GMP outcomes is remote interval meter reading, granular and timely load and voltage data, as well as a foundational capability being operational telecommunications with DERs.*

In addition to playing an integral role in enabling key GMP functionalities and achieving GMP objectives, AMF implementation provides considerable cost synergies with the overall GMP roadmap. First, the ability of AMF to provide more granular, timely voltage and energy data supports GMP planning and operations efforts that would otherwise require more feeder monitoring sensors at significant cost. Second, AMF implementation requires some of the same operational information, management, cyber-security, and operational telecommunications functionalities that are also critical to support other GMP objectives. Thus, AMF implementation reduces the cost of many of the GMP investments in underlying IT infrastructure, telecommunications, cybersecurity services, and core components.

4.2 Critically Linked Aspects of AMF and Grid Modernization

AMF provides near real-time monitoring of customer's electric usage data in 15-minute increments, can remotely disconnect/reconnect electric service, notifies Rhode Island Energy of power outages and restorations, and enables the delivery of usage information to customers and market participants. With the resulting increased system complexity requiring GMP for successful operations, AMF is a key enabler. AMF is foundational for GMP and significantly enhances its capability. A physical communication network and advanced metering infrastructure that generates much of the data needed for Grid Modernization will create a quantum increase in the use of digital information and controls will be needed to manage and improve reliability, security, safety and efficiency of the electric grid. It will also provide the information necessary to offer load management programs and time varying rates that can be used to shift energy consumption.

One of the most critical linkages between AMF and GMP is the information transfer that creates situational awareness of DER. When a utility is "DER aware", automatic isolation and restoration of faults and the associated system reconfiguration decisions need to take electrical load into consideration. Without AMF and Grid Modernization, a customer's electricity demand that is served "behind the meter" by the customer's DER is hidden from system operators. If the DER suddenly fails for any reason, the load must all be served by the grid. AMF coupled with the Grid Modernization DER Monitor / Manage, provides the communication network for the meter and DER inverters to send information to systems and grid operators that provides the necessary insight to account for hidden load in pre-transfer load analysis in order to operate the system safely and reliably. System awareness of DER is dependent on the data that AMF provides is pivotal to promote DER growth and unlock its benefits and value at the local and system levels.

ADMS is central to the linkage between AMF and GMP. As discussed above, ADMS Basic is being provided to Rhode Island Energy as a condition of the Acquisition, which costs Rhode Island Energy does not intend to seek to recover from its customers. It has already been implemented across the PPL footprint. Because PPL is providing the ADMS Basic system to Rhode Island Energy as part of the Acquisition the Company will use ADMS as the go-forward solution for implementing VVO. Critical AMF data such as interval voltage and reactive power data, and voltage real-time alerts, will be imported into ADMS, which has the capability to selectively acquire voltage data at points of interest on the network that will aid in monitoring and managing DERs.

Other functionalities include network model analytics to identify outliers such as distribution circuits that are missing a meter. As explained in Section 6.2, ADMS will have the ability to link outage data from the meters to operations by the time the first AMF meter is exchanged. Section 6.3 describes how ADMS will be advanced to include VVO which will be available by the end of 2025. Benefits will be accruing as the meters are installed and data is integrated into the system.

The Business Cases for GMP and AMF are complimentary, and care has been taken to harmonize them across three linkages as described in the Figure 4.1 below:

Figure 4.1: AMF and GMP Benefit-Cost Analysis Linkages

Linkage	AMF	GMP	BCA Coordination
Volt-VAR Optimization	From meters providing voltage data – 0.5% Energy savings; 0.167% Peak savings and avoided voltage sensors AMF information avoids an investment in distribution sensors to achieve VVO functionality.	Additional 1 – 3% energy savings	Performed sensitivity analysis described in Section 11.8.2 to assess BCA without VVO savings and savings related to Avoided DSP Sensors. BCA ratio (Nominal): 3.0 BCA ratio (NPV): 3.1.
Outage Management	Outage notification with AMF meters occurs 22 minutes faster than notification by customers calling in outages. Quantified faster notification through the ICE calculator as a customer benefit	All dispatching efficiencies will be quantified in the GMP. They result from ADMS where AMF outage detection is integrated with PPL restoration systems and processes	ADMS Basic is available at the end of the TSA. It is assumed to be available in both AMF and the GMP Business Cases. AMF Power Up restoration notification is enabled by AMF data input; however, for simplicity this AMF capability was not quantified in the AMF Business Case.
TVR	20% Opt-In participation is the base case assumption in the AMF Business Case based upon pricing that would be established without GMP inputs	GMP will provide information to forecast grid violations that are location specific. This can create a higher variation between peak and off-peak which could increase the incentives creating greater savings opportunities for customers. Therefore, TVR participation rates above AMF base case are possible with GMP	Potential TVR rate designs are presented in Section 13 along with sensitivities.

Rhode Island Energy is intentionally filing its AMF proposal separately from its GMP.[33] First, the Company believes so strongly in the fundamental importance of AMF that it has devoted its resources to building the business case and filing it as soon as it is ready. This Business Case describes the importance of AMF to transform the grid, which is time sensitive due to reliability and rapidly emerging system complexity requiring increased situational awareness. The time

33 While the filings are distinct, the Company is diligently working to ensure compatibility between the AMF and GMP filings.

sensitivity is driven by the State of Rhode Island's energy initiatives, which require increased situational awareness for the company to maintain its commitment to customer satisfaction, safety and reliability. AMF is the first step in the journey. Furthermore, as described in Section 11, a BCA ratio of 3.9 makes a compelling financial case to proceed. Second, by filing in advance of the GMP, the Company has chosen to emphasize the value of AMF and give due salience to AMF's benefits, even in the absence of other grid modernization investments. The sensitivity analysis that decouples GMP benefits from AMF, leaves the AMF stand-alone BCA at 3.0 nominal which is also makes a strong and compelling case to proceed with AMF independent of the GMP. Finally, the Company views AMF as a necessary first step toward enabling several grid modernization functionalities, as discussed above. The GMP functionalities are also necessary for the grid transformation, most of which are dependent on having AMF data inputs.

4.3 AMF Enables Data Analytics

AMF enables data analytics by providing granular information. Analytics generate actionable information from a vast amount of energy consumption and operational data.

AMF also provides visibility into outages and voltage information, which can help grid operators provide reliable electric power. Information gathered across the system can correlate events and usage signatures through data analytics, which can accomplish a variety of business outcomes and create a multitude of value streams such as:

- Evaluate the performance of EE and DR programs
- Generate customer insights
- Manage and prevent outages
- Size distribution assets
- Implement preventative maintenance
- Forecast and build predictive planning models
- Develop new rate plans and services
- Identify unbilled services
- Identify failing transformers, loose connections, and unbalanced circuits
- Improve asset data accuracy

- Improve mapping accuracy
- Improve planning accuracy and available DER hosting capacity
- Disaggregate loads into their components, e.g., refrigeration, air conditioning, lighting, etc.

Examples of business benefits from the granular AMF data are included in Attachment B. As the industry continues to evolve, the number and types of data analytics use cases, as well as the extractable value of available data from grid-edge devices, will continue to increase.

4.4 AMF Enables Integration of Other End-Point Devices

AMF can integrate end-point devices to provide additional value that is not quantified in the BCA. For example, AMF supports DER optimization by providing interval energy and voltage data at the customer level which is required for verification and settlement of DER services provided-to or received-from the grid. AMF also enables the exchange of information and/or control with in-home, business, or grid-connected DER technologies. Current state-of-the-art AMF electric meters can provide the functionality to ultimately enable management of behind-the-meter DER resources such as Solar PV, batteries, and EV charging/discharging. This coupled with standards-based inverters will be critical for reliability and safety; allow deferment of capital investments; improve hosting capacity; identify hidden load; and enable greater participation in TVR/TOU rates and DR programs.

In Rhode Island, there are several policies, programs, and technologies that impact customer loads such as energy efficiency ("EE"), solar photovoltaics ("PV"), electric vehicles ("EV"), demand response ("DR"), electric storage ("ES"), and electric heat pumps ("EH"). The AMF communication design in this AMF Business Case has anticipated endpoints in the National Grid 2022 base-case forecast that was published November 2021. It also considered end-point assumptions in the milestone GMP study years where the DER forecast is designed to meet the State's Climate Mandates.

Rhode Island Energy plans to utilize AMF to enable DER monitoring and management. The capability to monitor and manage DER systems will occur through coordination with PPL's ADMS using the AMF network. By utilizing AMF to leverage smart inverter capabilities, Rhode Island Energy expects to achieve improved visibility and management of DERs to offer more reliable and safer service during emergent and non-emergent conditions. For example, the smart inverters functionality associated with DER that can be unleashed includes capabilities to provide grid forming support, remote setting configuration, and emergent disconnect. With increased visibility of DERs, benefits can extend to areas such as improved planning, increased hosting capacity, improved power quality, and reduced interconnection costs. Rhode Island Energy plans to perform electric tests and validate the capability to receive, monitor, and manage the smart inverter's local communication interface by performing end-to-end operability tests between the DER and the Company's ADMS using the AMF communication network. PPL has experience directly monitoring and managing DERs through its ADMS in its Pennsylvania jurisdiction where it gained approval in December 2020 for tariff modifications to implement a DER Management Plan in PA (Docket No. P-2019-3010128).[34] Rhode Island Energy plans to similarly pursue a DER Management Plan in Rhode Island contingent upon the functionality being available to support it. The communication network is designed to support the future needs of flexible DER resources that are anticipated over the life-cycle of AMF.

4.5 AMF Enables Gas Operational Benefits and Efficiency

The aging natural gas distribution system in Rhode Island needs continuous maintenance and investment in its delivery infrastructure due to leak-prone pipes. The Northeast network has a strained and inadequate supply of natural gas in the cold winter months. LNG must be injected into the Rhode Island Energy gas system to maintain pressure and flow and adequate capacity to its end users. This unique gas supply system with its leaks and history of over-and under-pressure situations, especially during ever-increasing storms and extreme weather conditions, needs investments in AMF meters, networks, and systems. Strategies to minimize and/or mitigate risk associated with equipment failure, inadequate gas supply, dependence on LNG supply and processing, and numerous ongoing gas leaks are needed to make it safer, more reliable, more efficient, and minimize its impact on the environment. This can be done proactively by investing in tools, technology, people, and processes to better recognize and regulate problematic conditions and by having the ability to react immediately to mitigate the serious consequences if unpredictable events do occur.

The proposed Electric AMF investment provides a platform for gas AMF that will have increased functionality over the present gas AMR system. New Ultrasonic AMF gas meters coupled with gas methane detectors can become "smart grid" cornerstones for the gas system offering. Rhode Island Energy intends to apply these technologies, which will use the Electric AMF communication network to replace the gas AMR infrastructure with Ultrasonic gas meters and methane gas detectors having functionality that offers more granular gas information, sensing, remote disconnect, much-needed operational visibility and capabilities for increased customer awareness that leapfrogs the AMR capability that is available today.

4.6 AMF Enables Electrification of Transportation

On December 31, 2021, the Rhode Island Office of Energy Resources, Department of Transportation, and the Division of Motor Vehicles jointly submitted a Report to the General Assembly and the Governor, entitled "Electrifying Transportation: A Strategic Policy Guide for

[34] Petition of PPL Electric Utilities Corporation, *supra* note 29.

Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island" ("EV Report"). The EV Report outlines the latest strategy and plan for expanding electric vehicle charging station infrastructure across the State. The plan represents Rhode Island's latest policies to promote widespread EV adoption by improving customers' access to a charging infrastructure. The expected acceleration in EV adoption will be bolstered by Congress's Infrastructure Investment and Jobs Act, which will provide Rhode Island with an estimated $23 million of federal funds to expand the state's EV charging network.

Combined with planned incentives to encourage EV purchases by customers, the plan notes that the impact of EVs on Rhode Island Energy's distribution system will be very significant and that near full electrification of light-duty, medium-duty, and heavy-duty vehicles will require roughly 6,000 GWh of incremental electricity consumption on an annual basis.[35] The EV Report acknowledges the need for grid modernization and highlights the growing need to counterbalance the strain on the grid by moving EV charging demand to off-peak periods. As further documented in this Business Case, the EV Report similarly concludes that deployment of AMF is a necessary "prerequisite" for implementing time varying rate structures that can best alleviate strain on the grid by optimizing system utilization.

Several programs have already been designed and implemented to accelerate EV adoption in Rhode Island. As of December 2021, Rhode Island is home to 235 public charging stations with more than 500 ports. The charging stations that have been activated and approved in Rhode Island are shown in Figure 4.2.[36]

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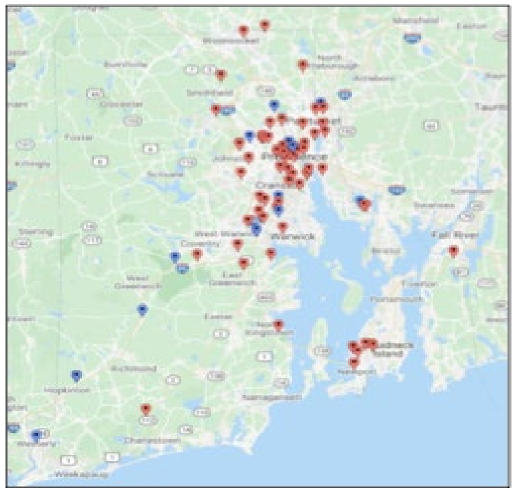
35 The EV Plan notes that the incremental load is approximately equivalent to 75% of Rhode Island's current annual electricity consumption.

36 Electrifying Transportation: A Strategic Policy Guide for Improving Public Access to Electric Vehicle Charging Infrastructure in Rhode Island, https://energy.ri.gov/sites/g/files/xkgbur741/files/2022-02/electrifying-transportation-guide-dec-2021.pdf (December 2021). Figure represents only publicly accessible Level 2 and DCFC charging; it does not include privately owned charging infrastructure or Level 1 charging access.

Figure 4.2: Activated and Approved Level 2 and DCFC Stations in Rhode Island

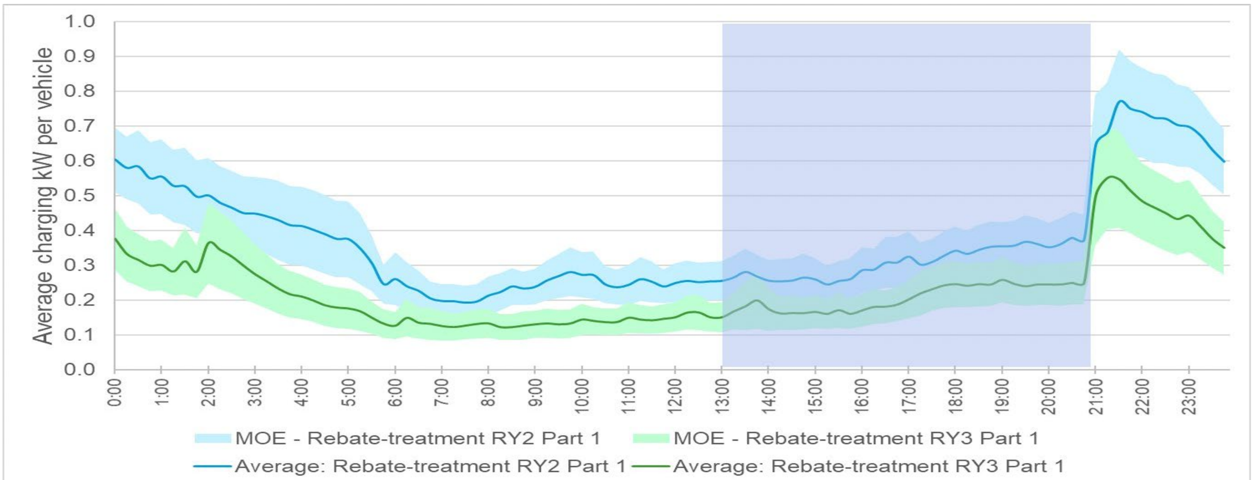


Electric vehicle charging causes strain on the electric grid primarily when vehicles are charged at the same time as peak demand – when Rhode Islanders are using the most electricity at the same time. Peak demand typically occurs in the afternoon and evening hours, and presently on an annual basis in the hot summer months. The AMF supports electrification of transportation because it enables time variable rate ("TVR") and critical peak pricing ("CPP") structures to incentivize customers to shift EV charging to off-peak/lower cost periods thereby helping alleviate grid strain. For example, the charging load profile of EV participants in various Time-of-Use incentive control groups has demonstrated early signs of success to motivate a shift of EV charging to off-peak periods as shown in Figure 4.3. Figure 4.3 shows the results when EV owners in the control group were given rebates for moving charging from on-peak hours to off-peak hours.[37] Other results from the Transportation Electrification Initiative indicated that EV owners receiving rebates reduced peak demand for EV charging by ~25-32%.[38] Managed charging solutions will be critical to enable load growth from electrification of transportation while optimizing the existing electric delivery infrastructure.

[37] Energy & Resource Solutions, *Rhode Island Electric Transportation Initiative Evaluation: Rate Year 3 Final Report*, at 19 (October 25, 2021).

[38] Energy & Resource Solutions, *Rhode Island Electric Transportation Initiative Evaluation: Rate Year 2 Final Report* at 3 (October 23, 2020).

Figure 4.3: Charging Load Profile for EV Participants by Control Group



Demonstrations have also shown that TVR can cause a concentrated demand growth during off-peak periods, particularly as customers use EV automated features to program their vehicles to begin charging immediately when the discounted rate became available. As a result, the distribution system experiences a stark increased load ramp at concentrated periods creating demand spikes that will need to be monitored and managed by the system operator. AMF provides visibility to this phenomenon and can be used to incent load management with rate structures like Time of Use ("TOU") TVR to help protect system reliability. AMF-enabled load management rate structures can also assist the distribution planning process to more fully optimize existing T&D assets and "right size" capacity investments.

Recent studies, including Rhode Island Energy's electric vehicle TOU pilot program results, have shown customers reduced their EV charging consumption during peak periods within an estimated range of 11 to 15 percent, on average, representing statistically significant changes in customer behaviors in response to price signals.[39] Due to the enabling functionality of AMF to implement TVR, Rhode Island Energy has included quantitative benefits in the BCA that recognizes a shift of EV charging to periods when energy is less expensive which reduces the total ownership cost for EVs and reducing EV load contribution to on-peak periods.

AMF is also a foundation to deploy future technology that may offer additional grid benefits through vehicle-to-grid services ("V2G"). V2G capabilities can support electric grid resilience and reduce costs by discharging electricity from EVs to the electric grid. For example, school buses that are not in use during the summer months can 'plug in' to the electric grid and discharge electricity during times of peak demand. Many vehicle manufacturers, such as Ford

[39] *Id. at* 28.

with their F150 Lightning truck, are including vehicle-to-home capability and anticipating V2G offerings through aggregate market participation.

4.7 AMF Enables New Value by Working With Others

Provided that there is communication bandwidth available to support additional functionality without sacrificing AMF offerings, Rhode Island Energy is open to exploring use cases that provide additional value through third parties. Examples are described below and use cases are further explained in Section 7.3:

- *Water Utility Joint Use:* Water utilities could leverage the proposed AMF infrastructure to support overlapping metering efforts, offering a "Metering-as-a-Service" to interested jurisdictions. The Company's platform could serve as the wireless FAN, backhaul, and back-office validation systems for smart water metering capability.
- *Streetlights:* The integration of AMF metering, wireless communications, and lighting control technology could yield environmental benefits achievable through remote controlled light emitting diode ("LED") technology applications in street lighting. The opportunity is further enhanced with customer specified operating schedules enabled by using the AMF metering for the energy consumption measurement of the individual streetlight. The further advancement of these technologies has been expanded within the street-lighting industry and other business use cases under the "Smart City" moniker. AMF wireless communication and metering capabilities are a prospective solution to managing deployments of community Wi-Fi applications, EV charging facilities, and mobile communication infrastructure (e.g., 4G LTE and 5G).

4.8 Anticipated Regulatory Actions

Rhode Island Energy plans to file its GMP with the PUC by the end of 2022. The GMP will be harmonized and synchronized with the fiscal year 2024 Infrastructure, Safety and Reliability Plan and this AMF Business Case.

Deployment of Gas Methane Detectors and Ultrasonic gas meters are being analyzed in conjunction with the Long-Term Gas Strategy. Preliminary plans are underway for accelerated deployment of methane detectors and Ultrasonic Gas Meters beginning after the Electric AMF has been completed starting in 2025.

TVR implementation is expected to lag customer meter installation to provide customers sufficient time to become familiar with their new meter and understand the new interval usage information and pricing options. In response to feedback from PST Advisory Group, Rhode

Island Energy does discuss a spectrum of potential TVR designs in this Business Case, including both for supply and delivery rates that could be considered in a future filing to be considered in a separate docket.

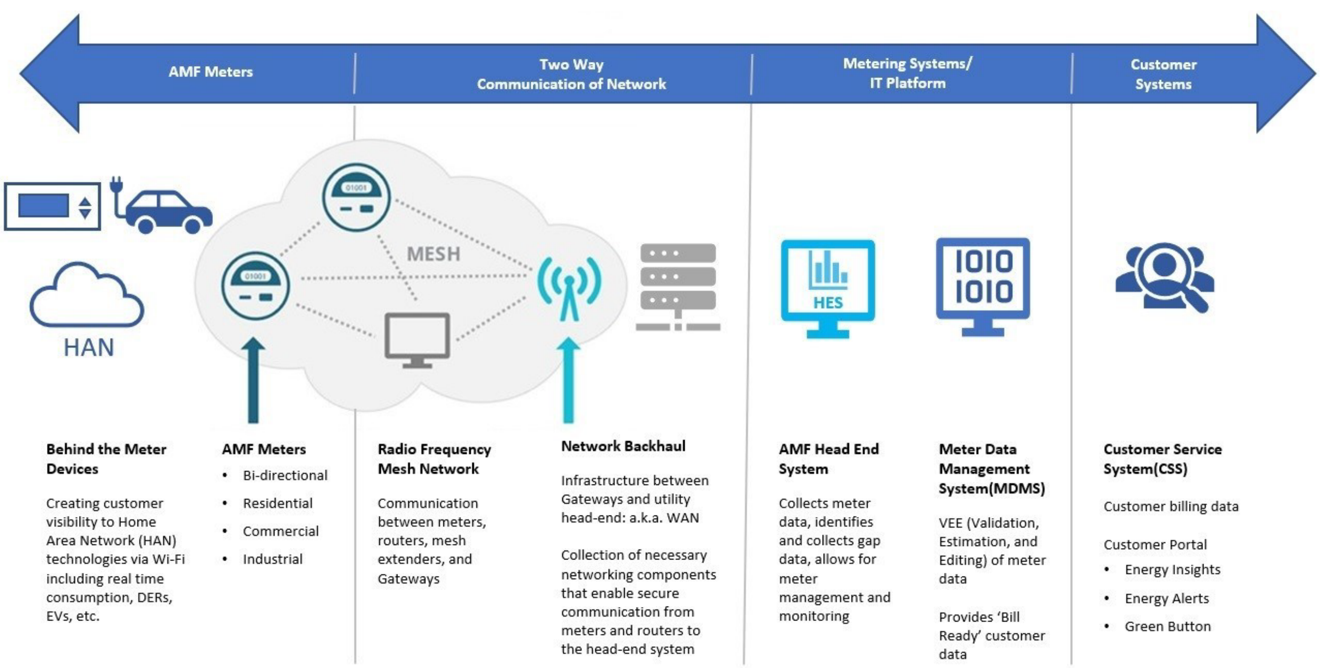
Section 5

SECTION 5: AMF TECHNOLOGY OVERVIEW

5.1 Overview of AMF Technology Elements

As illustrated in Figure 5.1 below, the proposed AMF technical solution includes four key advanced metering elements: (1) an integrated network of AMF electric meters capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications; (2) a two-way mesh communications network and IT infrastructure for transmitting the data and control signals that utilize IP-based RF mesh routing communications network using cellular backhaul technology; (3) metering systems/IT platform including a MDMS, head-end system ("HES"), and cybersecurity protections to securely and efficiently collect, validate, store and manage the meter data; and (4) customer systems including billing and a Customer Portal to provide energy usage data access, insights, and service offerings to enable customer energy management.

Figure 5.1: AMF Technology Elements



Rhode Island Energy is proposing AMF technology that will capture and transmit usage data back to the utility (15-minute intervals every 15 minutes for electric meter data) through an IP-based RF mesh routing communications network. This same information can also be communicated to customers' home area network ("HAN") devices directly from the electric meter. A series of gateway devices are strategically placed throughout the service territory to collect meter data and transmit the data through a backhaul network to Rhode Island Energy. The

HES then processes the data before it is transmitted to the MDMS, which performs data validation and generates the appropriate billing determinants for each customer. This data will be processed by the Customer Service System ("CSS") for billing, and it will also be delivered to the Customer Portal, which provides customers and authorized third parties with access to energy consumption data, energy insights, and service offerings.

5.2 Technical Overview of AMF Meters

Behind the Meter Devices

With the latest AMF meters, the consumer can see their actual energy usage and DER performance if they have a local Wi-Fi connection. Having knowledge of energy usage in near real-time and home analytics derived from that usage information can empower customers to make better energy choices. Insights and notifications if customers are exceeding pre-established usage thresholds will help them make behavioral changes and reduce complaints about high bills. This capability can promote energy efficiency, reduce high-bill complaints, increase the adoption of TOU/TVR rates and increase reliability and customer safety.

With a scalable and versatile meter platform, future applications and features can assist customers with EV charging needs, battery storage usage, and other home energy management requirements. Some of the latest AMF platforms are now designed with the capabilities to be updated remotely so that new applications can be activated based on the evolving needs of the system and customers. The latest AMF features also provide much shorter consumption measurement intervals and can increase operator visibility into the connectivity and control of DERs on the systems, including voltage conditions across the distribution network.

AMF Meters

The new AMF meters in Rhode Island will have the following capabilities:

Hardware Features:

- Remote connect/disconnect
- Multiple registers (kWh (real), KVAR (reactive), voltage)
- Integrated Wi-Fi
- Temperature Sensor
- Arc Sensor
- Accelerometer

- Cover Removal Switch
- Precision Network Timing

Metrology Features

- Sampling Rate – 14.6 Hz
- Max Harmonic – 63
- Measurement Period – 100 ms
- Reactive Power Metering
- Voltage Range
- Residential – 120/240V
- C&I – 120/480V

The AMF will also enable the following potential applications in the future:

Potential Application Features

- Waveform Data
- Measurement Data – voltage, current, kWh, KVAR
- Legacy Apps

Potential Grid-Side Applications

- Grid location Awareness – provides an accurate map of the grid which is critical to integrating DERs and supporting the mass adoption of EVs
- Anomaly Detection – Detecting faults along the distribution system which will improve reliability and outage response time resulting in shorter outages
- Intelligent Voltage Monitoring – near real time visibility into voltage performance which improves VVO and CVR resulting in reduced distribution losses and overall grid efficiency

Potential Consumer-Side Applications

- Home Analytics – Provides near real-time details into energy usage to consumers resulting in energy efficiency, load shifting, and reduced high-bill complaints

- Real-time High Energy Usage Alerts – Proactively notifies consumers when they are about to exceed a pre-defined usage threshold. Has shown to result in increased adoption of TOU/TVR and Critical Peak Pricing rates

- Meter Safety Alerts – Identifies electrical issues at the meter base allowing Rhode Island Energy to send priority alert messages, providing increased reliability and customer safety

5.3 Technical Overview of the Two-Way Communication Network

RF Mesh Communication Network

The key objectives in determining network approach are network resiliency, efficiency, scalability, and security. At the center of the AMF solution is a true mesh, peer-to-peer, secure AMF communications network that will be developed to allow transmission of metered data – voltage, current, alarms, connectivity status, etc. – to the HES. The mesh approach provides each endpoint, device, and router the ability to communicate in a peer-to-peer fashion, extending the coverage and the reliability of the network. A detailed planning of the network buildout will ensure a minimized number of hops each endpoint will need to take in order to get data back to a gateway, thus reducing message latency back to the HES. See figures 5.2 and 5.3 below for examples of routers and network gateways.

Figure 5.2: Substation / High-Capacity Network Gateways (109)

- Communicates with 4000-6000 endpoints (meters)
- Multiple antennas
- Battery backup power
- Gateway from head-end system to RF Mesh

Figure 5.3: Pole-Mounted Network Equipment

Routers (1280)

- Extends RF mesh coverage
- Small backup battery

Network Gateways (402)

- Communicates with ~2000 endpoints (meters)
- Gateway from head-end system to RF Mesh

Low latency is a key goal in ensuring efficient communication for customer programs, DERs, TVR, Demand Response, etc. Latency analysis defined further in section 5.6.

Another component of the network planning will be to ensure an appropriate number of redundant communications paths a device can take to prevent data loss if any particular router or gateway goes offline. This is especially important during storm situations where visibility into the network is critical. Asynchronous, multi-channel communication structure allows for flexibility and multiple paths to the gateways. The network is self-healing, featuring dynamic routing messages that automatically adjust for changes to endpoints and the introduction of obstructions, such as foliage or new construction.

Lastly, the immediate network design will account for scalability of future anticipated endpoints. As gas, DERs, and other devices are connected, additional load will be placed the network. Rhode Island Energy will proactively plan and ensure data reliability for all communications.

__Network Backhaul__

The network will consist of mesh extenders and border routers and will utilize a cellular network as backhaul unless Rhode Island Energy fiber is available, in which case it will be used. Data will be encrypted at transit at the networking layers on the devices using AES cryptography.

5.4 Technical Overview of the Metering Systems/IT Platform

Head End System

The Head End System ("HES") is the centralized data collection solution for all meter information coming from the network backhaul. The HES solution will provide a means to collect AMF data in a single repository and provides the tools to manage and monitor the advanced capabilities of the AMF meters. The HES will receive meter data from the Network Gateways through the Backhaul. The HES will attempt to collect any data not provided to at anticipated times via gap collection; the process of pulling data for missing reads. Data collected by the Head End System is delivered promptly to the MDMS for data validation and pre-billing use cases.

The HES solution provides communication to the meters, allowing it to both receive the meter data and also send commands such as ping requests, remote connects/disconnects, and over-the-air firmware updates. The ability to communicate to the meter through the HES provides monitoring capabilities to the Utility and enable functionality for outage mapping systems and visibility into potential safety concerns on the grid.

Meter Data Management System

Rhode Island Energy will provide a MDMS which collects metered data from the HES and performs Validation, Estimation, and Editing ("VEE"), a core function on the meter data that ensures bill quality data.

The MDMS will be sourced for various customer enablement programs such as the Customer Portal, the Supplier Portal, and providing Green Button Connect data.

The MDMS database will also populate many distribution operations systems to enable better near real-time visibility of the system to the operators and to enable more efficient management of the grid and the many DER devices connected to the grid. This will significantly improve the safety and reliability of the electric distribution system in the future.

Cyber Security Considerations

Ongoing testing coupled with fundamental design characteristics are being proposed to ensure the entire system is secure from the meter through the communication network; the backhaul system; the HES; the MDMS; and to the CSS.

Rhode Island Energy will provide data encryption capability for transit at the networking layers on the devices using an advanced encryption protocol standard to protect the transfer of data online. The Company also will use a uniquely keyed application layer messaging encryption to ensure privacy between an endpoint and the associated head end system. This unique three-layered approach provides best in class cryptography and privacy controls. Resistance and local security tamper resistance protects devices from being modified and allows for monitoring. Various attributes include:

- Firmware Integrity – Radio, Metrology and Apps images are digitally signed;
- Port Hardening – JTAG and DEBUG disabled in operational mode. Optical port disabled by default;
- Tamper Alert – Includes tamper alerts including cover removal. Alert is automatically generated and communicated to the head end when event occurred;
- Encryption at Rest – All private keys, passwords or other confidential information is stored encrypted in flash memory;
- Wi-Fi interface is disabled by default and can only be enabled from HES;
- WPA2 and WPA3 security mode are supported; and
- Network Isolation Wi-Fi Network.

The Company also will have a third-party conduct penetration testing focusing on the network and software layers. The Company anticipates that the hardware penetration will be performed on a per project basis, depending on the level of changes and attacks surfaced related to each device and will target the external network environment of PPL's cloud infrastructure. The Company also plans to perform automated security testing as part of the secure development lifecycle.

5.5 Technical Overview of Customer Systems

Customer Programs and Billing

During the customer billing window, the MDMS will gather customer billing data and send it for processing to the CSS. The CSS provides tools to create and manage customer programs such as TOU/TVR, Net Metering, and Customer Opt-Out and apply those programs to customer billing. The CSS marries the MDMS bill determinants to the CSS program's rates to complete customer billing.

<u>Customer Portal</u>

The Customer Portal provides customers with access to energy consumption data, energy insights, and service offerings. Customers will have multiple options on how they can manage their data, such as the ability to create alerts based on different energy consumption criteria that they would like notification on. Because key considerations for these customer insights are both accuracy and speed, Rhode Island Energy's network is designed to provide reliable, accurate, secure, and prompt data.

Another avenue for customer to monitor their usage data will be through Green Button Connect ("GBC"), which is available to customers through the Customer Portal which customers can access through the web or mobile devices. In this way, the customer can authorize the use of their energy data to provide demand reduction awareness and notifications to avoid high-cost hours of consumption. An example of what data the customer would provide to third parties through GBC is shown below in Figure 5.4.

Figure 5.4: Green Button Connect Customer Data

Usage Information

For location: Green Button Usage Data

Summary of Usage Information*

* Note: Quality of this summary and information is "raw: data that has not gone through the validation, editing and estimation process"

Current billing period as of: 2022-03-03 15:20
Consumption(Real energy in kilowatt-hours) :357.000

Last billing period: 2022-01-27 00:00 to 2022-02-25 00:00
Consumption last period(Real energy in kilowatt-hours) :1,895.000

Meter Reading Information

Type of readings: Electricity, Monthly Electricity Consumption, Real energy in kilowatt-hours

Detailed Usage

Start date: 2022-02-01 00:00 for 30 days

Data for period starting: 2022-02-01 00:00 for 1 day

Energy consumption time period	Usage (Real energy in kilowatt-hours)	Events occurred
2022-02-01 00:00 to 2022-02-02 00:00	63.000	

Data for period starting: 2022-02-02 00:00 for 1 day

Energy consumption time period	Usage (Real energy in kilowatt-hours)	Events occurred
2022-02-02 00:00 to 2022-02-03 00:00	58.000	

Data for period starting: 2022-02-03 00:00 for 1 day

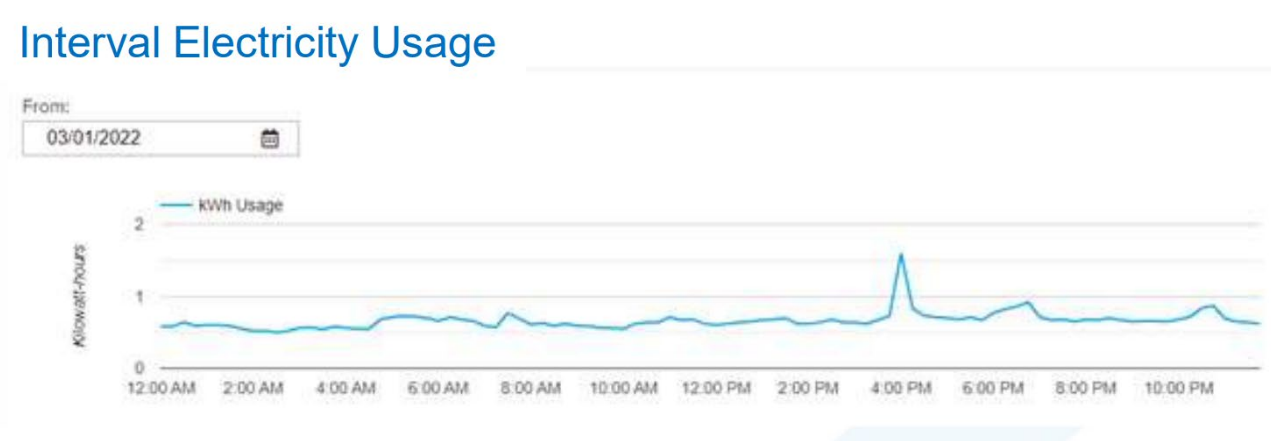
Energy consumption time period	Usage (Real energy in kilowatt-hours)	Events occurred
2022-02-03 00:00 to 2022-02-04 00:00	65.000	

5.6 Evaluation of Data Latency Outcomes for AMF Solution

One of the key design considerations is "data latency," which refers to the time delay from when a meter or endpoint captures data to when the information is available to a customer or authorized third-party service provider. With the evolution of energy services, customers and third parties expect to have access to more granular data. Moreover, the timeliness and availability of the energy usage data are of growing importance to support DERs, TVR, enhanced customer education, and DR capabilities.

The Company's AMF proposal provides access to energy usage information for all customer classes through three primary channels: (1) the Customer Portal; (2) facilitating data sharing with authorized third parties using GBC, which will be accessible from the Customer Portal; and (3) directly from the meter through a HAN. The first two channels, require meter usage data transmission from the meter, through the end-to-end AMF solution, to the data-sharing platforms in the Customer Portal. Through this data process, the Company proposes to provide access to 15-minute raw electric interval usage data available to customers every 30 to 45 minutes. An example of how this usage data would be presented to the customer is shown below in Figure 5.5.

Figure 5.5: Interval Electricity Usage



Customers will ultimately have access to the Customer Portal through the web and mobile devices. Billing quality data will be available within 24 hours. Billing quality data is defined as data that has undergone VEE. All usage data from the AMF meters gets received first in the HES and then passed along to the MDMS, where it goes through VEE.

The HAN, the third channel, provides optionality for customers to obtain real-time usage data directly from the meter. Electric AMF meters contain a physical radio and associated firmware to provide a wireless signal to HAN devices for data transmission. Similar to how devices are connected in homes today through a wireless router, meters can be paired with in-home devices that can be deployed to display customer data in real-time. Customer data can also be made available to customer mobile devices, leveraging HAN and third-party internet-based service offerings. A description of data access channels and latency parameters is provided in Figure 5.6.

Figure 5.6: Data Access Channel Descriptions and Customer Data Access Latency

	Description	Customer Data Latency
Customer Portal ("CP")	Customers can access their own usage data directly and download it to share with third parties.	• For electric customers, 15-minute raw interval data will be available every 30 to 45 minutes.
Green Button Connect ("GBC")	Facilitates computer-to-computer communication to allow for a standard protocol by which customers can provide authorized third parties direct access to energy usage data.	• Bill quality data will be available within 24 hours
Meter to Home-Area- Network ("HAN")	Transmits data directly from the meter to HAN.	• Real-time raw energy usage data.

The above channels with their respective data latencies support the customer-facing functionalities and related benefits outlined within this Business Case. The channels also support a variety of grid-facing functionalities and related benefits where lower data latency may be required. Figure 5.7 categorizes the AMF functionalities that are dependent on customer data and the required latency. In addition, the Company has included data latency benchmarking information from peer AMF implementations in Attachment E.

Figure 5.7: AMF Customer Data Access Latency Requirements

	AMF Functionality	Data Latency Requirements	
		Billing Quality Data	Raw Data
Customer - Facing	CP - Customer Data Access	X	X
	CP - Customer Energy Insights	X	
	CP - Bill Alerts	X	
	CP – GBC	X	X
	Integration w/ In-Home Technologies		X
	TVR - Customer & DER	X	X
	Remote Interval Meter Reading	X	
Grid-Facing	Theft Detection	X	X
	Voltage Measurement - Voltage Conservation		X
	TVR - Load Shift	X	
	Load & Voltage Data - Situational Awareness/Forecasting	X	X

In addition to displaying usage data through a HAN or business-area network, home energy management systems will be able to receive and send secure communications with the Company or third-party market entities. This can enable real-time customer access to meter data, including load/price signals and real-time integration with smart devices such as thermostats, water heaters, and other appliances. These enhanced service opportunities will be promoted through the Customer Portal.

Another key design attribute is the flexibility and adaptability of the solution to meet evolving customer and grid needs. The solution the Company proposes represents the latest generation of maturing AMF technology; with capabilities that include over-the-air firmware upgrades and grid-edge computing platform functionality. Over-the-air firmware updates are critical for future-proofing capability and maintaining a security system. Firmware upgrades can be sent over the air to keep devices up to date with the latest functionality and to protect customers and the Company against new cyber vulnerabilities. Without over-the-air capability, implementing updates becomes cost prohibitive because the expense to physically visit each field location to perform updates is too high. Leveraging over the air functionality will directly contribute to the reduction of truck rolls and ultimately greenhouse gases.

In the future, Rhode Island Energy can deploy supporting software applications to the meters for both grid- and customer-facing use cases ranging from integration of additional DER and EVs on the grid to providing more choice, convenience, and control through additional information. The Company, based on the above-mentioned data, research, and previous experience, believes the grid-edge computing platform will enable significant future customer- and grid-facing capabilities. The Company is planning to work with stakeholders and third parties to identify and consider new capabilities and functionalities to ensure that evolving customer and grid needs continue to be met in the future.

Section 6

SECTION 6: FUNCTIONALITY ROADMAP

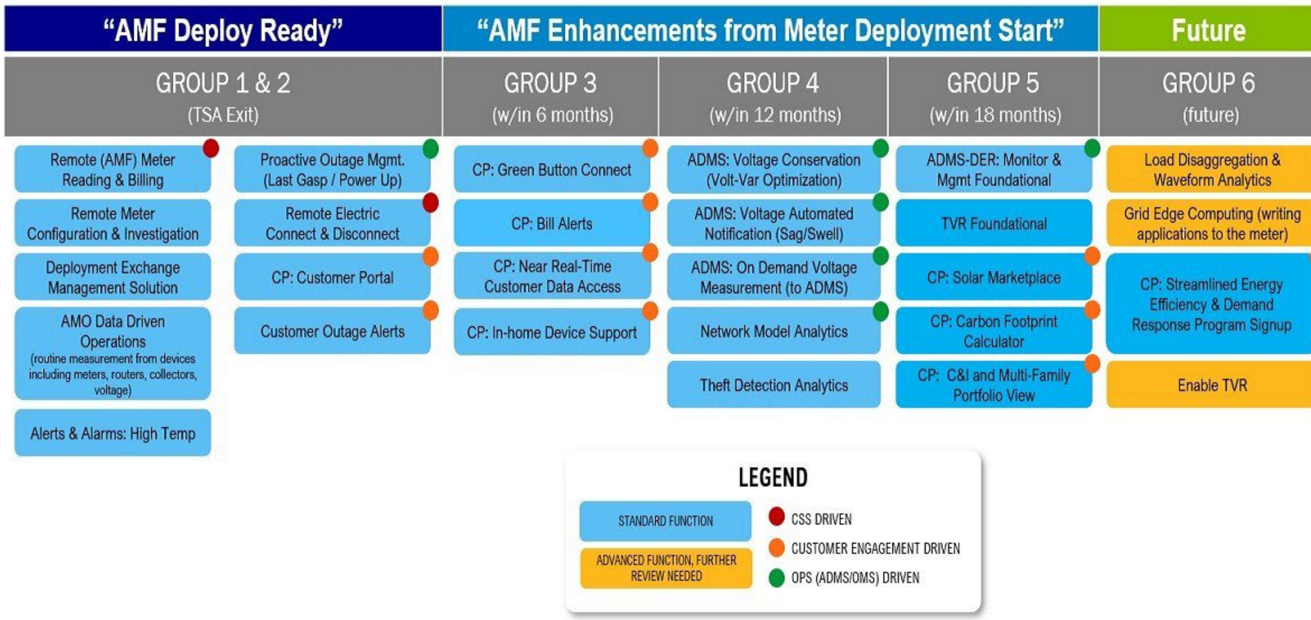
This Section presents a roadmap that describes the AMF functionalities and a three phased approach for implementation: those available at the time of TSA exit; during AMF deployment and planned for release thereafter. Also, the envisioned data analytics that are AMF enabled are described.

A significant amount of IT planning, development, and system integration is required to achieve various AMF-enabled functionalities. Functionality releases are often dependent upon one another and require significant coordination. This is particularly the case as it relates to the AMF functionality being developed during and shortly after the development activities affiliated with the Transition Service Agreement ("TSA") exit. The TSA is an agreement between National Grid USA Service Company, Inc. ("National Grid Service Company") and Rhode Island Energy where, among other things, National Grid Service Company operates and maintains its back-office systems for Rhode Island Energy customers for up to two years after the Acquisition. During this period, customers will have their meters read through the existing AMR system and be billed accordingly; in parallel, PPL and Rhode Island Energy will develop systems and processes so they can exit the TSA by transferring Rhode Island Energy business operations PPL systems. PPL has also planned for AMF-enabled functionalities to be available as presented in this Section in a best-estimate roadmap. The strategy is to align Rhode Island Energy AMF systems to mirror the current AMF architecture and functions that PPL has used in Pennsylvania as closely as possible.

6.1 AMF Electric Roadmap

Various AMF functionalities presented in blue and orange boxes in Figure 6.1 are defined to be released in three phases, (1) those that are "AMF Deploy Ready" and will be available at the end of the TSA-Exit milestone (*Groups 1 & 2*); (2) "AMF Enhancements During Meter Deployment" (*Groups 3, 4, and 5*); and (3) those "Future" enhancements (*Group 6*) that will be available after the AMF meters have been deployed. The systems that are required to enable the functionalities are also noted in Figure 6.1. Those functionalities in blue are standard and reasonably defined, while those in orange are future in nature and will require additional definition.

Figure 6.1: AMF Functionality Roadmap



Timing of the functionality is divided into 6 Groups. Groups 1 and 2 are available and enabled at the end of the TSA period and identified as "AMF Deploy Ready" meaning the functionality is planned to be in place when meter deployment starts. Groups 3, 4, and 5 are categorized as "AMF Enhancements During Meter Deployment" where this functionality will be phased in six month increments after meter deployment starts. Group 3 is planned within 6 months after deployment starts; Group 4 is available within 12 months after deployment starts; and Group 5 is planned to available by the time that the meter deployment is completed (18 months after starting deployment). Group 6 functionalities are planned to be available after meter deployment has been completed. Cost and benefits have been included in the Business Case for all functionalities described in all six (6) Groups. Costs and benefits for functionality in Group 6 are less certain than those that are coming earlier. As future requirements become firm, the cost and benefits may need to be adjusted. Because the AMF platform can enable additional functionality beyond that described herein, the incremental costs and benefits associated with new capabilities that may be defined and developed over the next 20 years beyond what has been contemplated in this proposal.

6.2 AMF Deploy Ready Functionalities at TSA Exit

Figure 6.2 below describes functionalities in Groups 1 and 2, which will be available at TSA Exit and functioning when the meter deployment begins and beyond. PPL already has significant experience in deploying this functionality in its other footprints. For example, AMF outage detection integrated with PPL restoration systems and processes is planned to be implemented in tandem with the meter deployment utilizing prior PPL system integration capability. The PPL approach differs from National Grid's Updated AMF Business Case where achieving automatic power outage notification was anticipated to take a few years given the time that they needed to integrate Last Gasp and "Power-up" meter information with the National Grid's restoration system. PPL has had the integration operational for several years so the effort at hand is to migrate the pre-existing capability to Rhode Island. Given the availability of ADMS Basic from PPL as a condition of the Acquisition, it facilitates the integration of the outage information from the AMF meters with the operating domain early in the AMF deployment process, thereby making dispatch efficiencies and storm response benefits readily available early in the AMF project.

Figure 6.2: AMF Deploy Ready Functionalities – Available at TSA Exit

AMF Functionality	Working Definition
Remote (AMF) Meter Reading & Billing	Reading and billing interval energy usage at standard latency using AMF meters.
Remote Meter Configuration & Investigation	Remote "over-the-air" firmware and software updates & investigation of meter malfunctions. Proactively enabled energy data analytics and reactively enabled by alerts and alarming.
Deployment Exchange	The Meter Deployment solution to status and update the accounts that have been exchanged as part of the AMF deployment. Traditionally this involves exchanging of a "Population file" and syncronizing with the customer system and asset system to reflect the newly installed AMF meter.
AMO Data Driven Operations	Implementation of operational dashboards to manage the AMF Network and associated endpoints. For example, configuration management, firmware levels, endpoint inventory, reading percentages, interval completeness, and overall network health.
Alerts & Alarms: High Temp	Alerting & Alarming - Alerting when configurable internal temperature is reached and sending to work management system for disposition
Proactive Outage Management (Last Gasp / Power-up)	Alerting operations and OMS System when meter experiences an outage or power is restored.
Remote Electric Connect & Disconnect	Activation of remote electric meter switch to turn on/off service; also includes meter tamper alerts and usage analytics.
CP: Customer Portal	Customer-facing usage data availability, usage analytics, normative comparisons, and other data-driven customer experience features. Provide omni-channel access and continuous improvement through an agile and iterative development approach that incorporates on-going customer experience updates.
Customer Outage Alerts	Proactive communication of outages identified in the OMS system to customers.

6.3 AMF Enhanced Functionalities During Meter Deployment

The enhanced functionalities enabled during the Meter Deployment period are described in Figure 6.3 and will deliver benefits to Rhode Island customers throughout the deployment period and beyond.

Figure 6.3: AMF Functionalities During Meter Deployment

AMF Functionality	Working Definition
CP: Green Button Connect	Enables customers to transfer energy usage data at a standard latency to authorized third parties.
CEMP - Bill Alerts	Alerts for variety of customer needs. Examples include projected high-bill (consumption and/or costs), prediction of peak demand or usage, and customizable threshold alert at various points during a billing period.
CP: Near Real-Time Customer Data Access	Availability of near real-time raw usage data through the customer portal. This allows 15-minute electrical raw usage data, available within 30-45 minutes, updated with bill quality data within 24 hours.
CP: In-Home Device Support	Enable communications between a customer owned home Device and the AMF meter.
ADMS: Voltage Conservation (Volt-Var Optimization)	Providing interval meter voltage and reactive power data to the ADMS to support conservation voltage reduction (CVR) and Volt-Var Optimization (VVO).
ADMS: Voltage Automated Notification (Sag/Swell)	Configurable real-time alert for momentary under or over voltage on a meter, integrated to ADMS for immediate action.
ADMS: On Demand Voltage Measurement (to ADMS)	ADMS function to ping networked electric devices and meters for voltage measurements.
ADMS-DER: Monitor & Management	Enabling the ability to monitor & manage distributed energy resource (DER) inverter based infrastructure (eg. battery banks, solar PV, net-meters).

Figure 6.3: AMF Functionalities Enabled During Meter Deployment (continued)

AMF Functionality	Working Definition
Network Model Analytics	MDMS functionality to support analysis of the network, identifying outlier issues for investigation (e.g. misassociated meters).
Theft Detection Analytics	MDMS functionality to identify outlier patterns that indicate potential energy theft.
CP: Solar Marketplace	Customer portal functionality that creates an integrated marketplace for customer research of solar PV adoption.
CP: Carbon Footprint Calculator	Customer portal functionality that creates an ability for customers to calculate carbon footprint based on usage data and actions to better manage usage.
CP: C&I and Multi-Family Portfolio View	Customer portal functionality that enables a portfolio view of C&I facilities as well as properties for multifamily unit owners and managers.

6.4 AMF Future Functionality

Figure 6.4 describes when the AMF-enabled future functionality is envisioned (Group 6) to be developed and implemented. Rhode Island Energy will evaluate the future functionalities (e.g., proof of concept) as the Company implements the AMF solution. TVR functionality will depend on regulatory approval of a TVR structure: implementation is expected to lag customer meter installation to provide customers sufficient time to become familiar with their new meter and understand the new interval usage information and pricing options. All AMF meters, network and systems infrastructure must be deployed before TVR can be implemented to support communication of the time varying rates as well as having the ability to process the billing complexity.

Figure 6.4: AMF Future Functionalities

AMF Functionality	Working Definition
CP: Streamlined Energy Efficiency & Demand Response Program Signup	Provide customers with streamlined ways to access information and programs on ways to reduce energy consumption.
Time Varying Rates (TVR) Foundational	Interval meter data with VEE integrated to billing systems and billing system functionality to support Time Variable Rate billing.
Load Disaggregation & Waveform Analytics	Provide a breakdown of electricity consumption by appliance or end-use for educational purposes and/or recommended actions to save, available through the customer portal.
Grid Edge Computing (writing applications to the meter)	Metering platform for customer- and grid-facing software applications at the meter.
Enabled Time Varying Rates ("TVR")	Customer engagement and approved regulatory framework to support Time Variable Rate billing options to customers.

6.5 Rhode Island Energy AMF Development Planning Approach and Estimating

Based on the review of the scope, the initial view of interdependencies, and the AMF filing considerations, the development effort was differentiated between application and functionality required by the close of TSA Exit ("AMF Deploy Ready") and functionality that is required to support AMF Programs in the timescale after TSA Exit ("AMF Enhancements"). The system functionality required in the first category of "AMF Deploy Ready" was further refined to consider the program milestones required before the TSA Exit is reached, such as the capabilities needed to support the deployment of the Rhode Island Energy communication network. Other programs within the "AMF Deploy ready" group are solely focused on supporting the TSA Exit milestone that will coincide with the beginning of meter exchanges. This approach provides an implementation plan prioritization to meet the critical milestone of TSA-Exit and the functionality as defined in this AMF Business Case. With the abundance of concurrent requirements, an agile approach will be used to manage the many parallel systems development initiatives.

6.6 Rhode Island Energy AMF Systems Cost Estimating Method

Two stages were used to develop the AMF Systems cost estimates. The first was to review the original estimate from National Grid's Updated AMF Business Case and apply experiences from the Pennsylvania AMF deployment and system experiences to improve the estimate. The second involved working with an external system integrator to apply wider industry experience specific to AMF and related IT systems and to review and update the entirety of the metering systems program scope.

1. Develop metering requirements
2. Assess the requirements for complexity & interfaces needed
3. Assess the conversion requirements & complexity
4. Allocated effort to appropriate delineation (TSA-Exit or AMF)
5. Applied the requirement and interface counts

Given the complexity of the IT systems development and the criticality of to the AMF Business Case, this level of IT systems planning was needed to provide confidence in the cost estimate and the development timing.

6.7 Roadmap Functionality Comparison: Rhode Island Energy and National Grid

The Design and Deployment for both plans consist of similar steps including Back-Office Systems, Field Network Deployment and an 18-month Electric Meter Deployment. Customer Engagement is also structured in three phases triggered off of the same metrics. For Benefits Realization, PPL is bringing ADMS Basic to Rhode Island customers as part of the Acquisition, making operational integration with AMF information available much sooner than anticipated in the National Grid Updated AMF Business Case. Because of this integration, which will be in development and completed before exchanging meters, incremental benefit realization can be achieved with each meter upgrade. This contrasts with National Grid's Updated AMF Business Case, in that the integration of AMF data with the ADMS operational data was scheduled to occur after meter deployment (through a separate investment) and as result, benefit realization for items such as outage notification, remote disconnect, and dispatch efficiencies for storm response took some time to achieve. This timing difference is significant because it impacts when value can be realized which, in turn, impacts the BCA.

Section 7

SECTION 7: CONSIDERATION OF ALTERNATIVE BUSINESS MODELS

This Section describes new and emerging ownership approaches to the implementation of various AMF elements and how these opportunities have been considered in Rhode Island Energy's AMF proposal.

As part of the development of National Grid's AMF Updated Business Case, the Company, while under National Grid ownership, retained Accenture to perform a detailed assessment of alternative business models. The scope reviewed approaches to the AMF solution by focusing on four discrete areas:

- New and emerging approaches to AMF
- "As-a-service" offerings
- "Shared services" opportunities; and
- The relative magnitude of "communication infrastructure backbone" and the impact of potential alternatives.

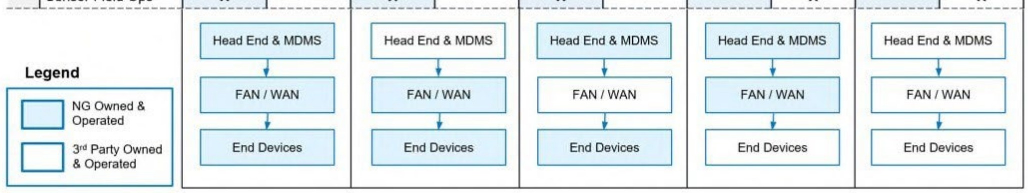
In summary, the assessment found that the AMF ownership model that the Company proposed in its PST Plan, while under National Grid ownership, constituted an innovative and cost-effective approach. The alternatives, which are discussed below, were found not to be cost-effective or presented significant implementation risk due to the lack of market maturity for some options. Rhode Island Energy agrees with this assessment.

Figure 7.1 presents AMF vendor service offering options to utilities, ranging from licensed to an end-to-end AMI/AMF as-a-service ("AMI/AMF aaS") subscription model. The vendor service offerings are independent of the underlying technology, and whether the utility networks are shared is defined as follows:

- **A closed utility AMF network** is one in which only the utility's operational devices are used, and such devices are only used to transmit the utility's operational data – the architecture is closed to other third-party-owned devices (e.g., water meters, streetlights).
- **A shared utility AMF network** is one in which other third-party-owned devices can connect with and transmit data across a utility's AMF network – the architecture is shared between the utility (with the primary function being AMF) and other third-party-owned devices.

Figure 7.1: Defining AMI/AMF aaS Offering (Source: Accenture Report)

		Licensed		Software As-a-Service		Network As-a-Service		Meters As-a-Service		AMI As-a-Service	
		Utility	Vendor	Utility	Vendor	Utility	Vendor	Utility	Vendor	Utility	Vendor
Ownership	Meters	X		X		X			X		X
	Modules	X		X		X			X		X
	Sensors	X		X		X			X		X
	Networks	X		X			X	X			X
	Software	X			X	X		X			X
	IT Infrastructure	X			X	X		X			X
Operations	IT Services	X			X	X		X			X
	Back-office Ops	X		X			X	X			X
	Network Field Ops	X		X			X	X			X
	Endpoint Field Ops	X		X		X			X		X
	Sensor Field Ops	X		X		X			X		X



Vendor service offering definitions for the above models is shown below:

- **Licensed** software is the traditional approach to utility software procurement which places full financial and operational control of all assets on the utility. Vendor software and IT infrastructure are purchased by the utility and installed on the utility's premise or in the utility's private cloud.

- **Software-as-a-Service ("SaaS")** is a vendor-managed service offering where the third-party vendor is responsible for the upfront investments of purchasing, setting up, maintaining, managing, and monitoring the cloud-based IT infrastructure and software. The third party also provides labor to manage and maintain the systems.

- **Network-as-a-Service ("NaaS")** is a vendor-managed service offering that provides turnkey FAN/wide-area network (WAN) ownership and operations (back-office and network field operations). Typically, however, vendors that offer NaaS effectively "de-risk" investments into WAN by leveraging their network provider partnership ecosystem to lease backhaul/backbone bandwidth.

- **Meters-as-a-Service ("MaaS")** is a vendor-managed service offering that provides services around the lifecycle of the meters themselves including finance/ownership, procurement, installation, and field maintenance.

- **AMI/AMFaaS** is a vendor-managed service offering that provides a turnkey end-to-end solution that combines SaaS, NaaS, and MaaS to provide a fully integrated solution for clients.

Managed services provided by vendors may include components of one or more of the above, most likely using SaaS as the foundational offering, then adding components of NaaS, then AMI/AMFaaS in that order. On the one hand, "as-a-service" offerings aim to reduce upfront costs and the total cost of ownership while also ensuring that utilities have access to the latest technologies and periodic software upgrades. On the other hand, such models decrease a utility's control over future technology development and represent new commercial contracting risks.

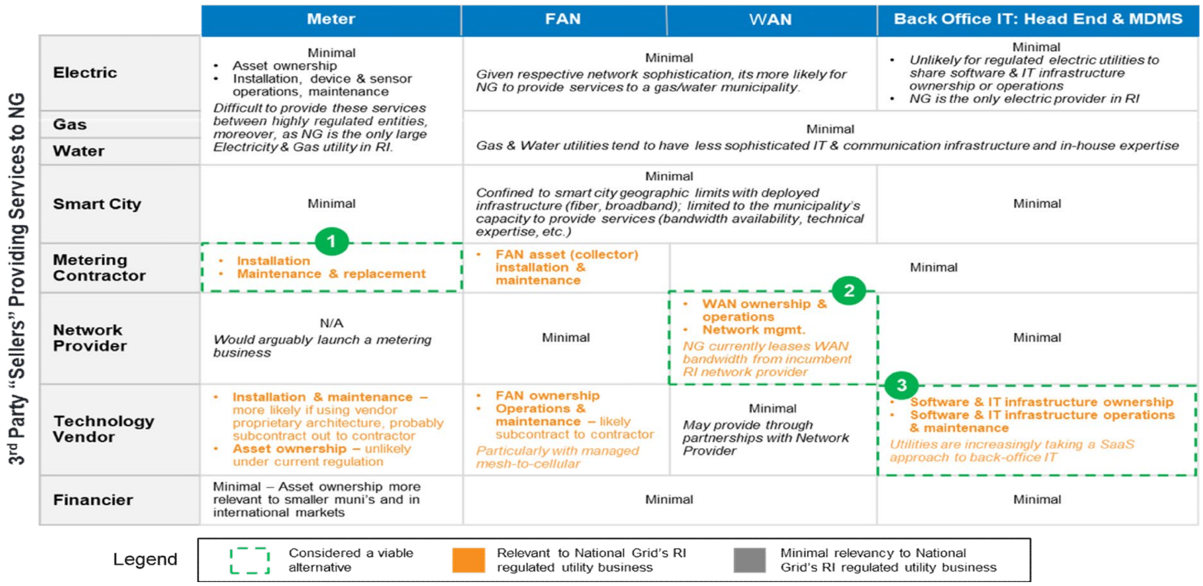
7.1 New and Emerging Approaches to AMF

To identify alternative viable operating approaches, Accenture conducted a market scan for findings of existing and emerging capabilities around the world based on primary research of public information, utility and telecom industry consulting experience, interviews with market participants (e.g., Google Fiber and Leidos), and workshops/discussions with a variety of experts. The market research consisted of approximately 40 alternative ownership examples of utility advanced metering networks (i.e., electric, gas, and water) of entities including investor-owned utilities ("IOUs"), municipal utilities, co-operative utilities, network, and telecom infrastructure and metering providers. The market research findings analyzed the ownership and operations of AMF technology solution components considering both shared and closed networks.

7.2 Consideration of "As-a-Service" Offerings

Based on the Rhode Island regulatory context, combined with an understanding of market participant offerings and PPL's own experience with AMF deployments in Pennsylvania and Kentucky, potential "as-a-service" procurement opportunities are identified and considered in Figure 7.2 below:

Figure 7.2: Services Rhode Island Energy Could Procure From Third Parties



Because Rhode Island Energy is as the primary delivery service provider for electric and gas service in Rhode Island, service offerings provided by other regulated or government entities (e.g., gas delivery, water, smart cities) to the Company are not practical. The Financier service model, which is seen in international markets, is not considered practical. Under a Financier service option, a specialty financial firm or infrastructure investor provides meter asset ownership and receives "rent" from utilities or energy suppliers. It exists only in specific international markets where the governments and regulators have promoted competitive metering models and developed associated market rules for participation throughout the value chain. There are technological downsides to this approach, which requires plug-and-play metering solutions. For example, the latest AMF technology that includes grid-edge computing and application capability has interoperability limitations that would render a Financier structure more difficult and potentially impractical to implement.

Third-party service providers could potentially provide services to support the Company's AMF solution including metering contractors, network providers, and technology vendors. Consideration of these providers and services within the Company's proposal is described below:

- A metering contractor can provide services such as meter installation and maintenance. The Company's BCA assumes a combination of internal and outsourced resources to install and maintain the meters. The Company will make resourcing decisions to seek efficiencies without increasing costs.

- A FAN contractor can provide services such FAN installation and maintenance where the BCA assumes outsourced resources to install and combination resources to maintain the FAN equipment. Rhode Island Energy will make resourcing decisions to seek efficiencies without increasing costs.

- A cellular network provider can provide WAN communications ownership, operations, and management. The Company currently leases bandwidth from a network provider and assumed that this would continue in the BCA to provide meter data backhaul for the AMF solution.

- A technology vendor could also provide a suite of services, including meter installation and maintenance; FAN installation and maintenance; and software hosting and operations.

Rhode Island Energy's proposed AMF solution includes SaaS for the back-office IT systems, including the HES and MDMS. With respect to technology vendor meter ownership, the Company does not believe this option is economically viable, particularly considering the Company's access to capital and low financing costs. In addition, market research also indicates a nascent market for AMF network and infrastructure services defined by small-scale engagements with little indication of business success.

In summary, Rhode Island Energy's proposal includes "as-a-service" approaches for the WAN and back-office IT systems. Rhode Island Energy also plans to outsource the network installation and pre-sweeps. The meter installation will utilize a combination of in-sourced and out-sourced resources during the detailed meter deployment. The SaaS approach for the back-office IT systems is a general trend in the IT space and is increasingly being adopted as part of AMF implementations. The Company believes its proposed AMF solution approach leverages third-party services where they can improve the cost-effectiveness and/or capabilities and quality of the solution.

The approach is consistent with the compiled market research that is organized by closed and shared networks in Figure 7.3 and Figure 7.4. In general, large U.S. utilities own and operate the FAN component of the AMF network and own the meters (i.e., end devices). Increasingly, however, utilities of all sizes have been outsourcing back-office IT services and look to lease backhaul/backbone bandwidth WAN from network providers.

Figure 7.3: Market Research Inventory of Closed AMF Ownership Models

	Back Office IT (MDMS, Head-end)	WAN	FAN	End Devices	Telecom Model / Architecture	Shared/Closed Network	Own/Operate Network
Lansing Board of Water & Light	Leidos SaaS	Leidos NaaS	Leidos NaaS		Unknown	Closed	Procured aaS
City of Copperas Cove (Water)	FATHOM SaaS (MDMS)				Unknown	Closed	Procured aaS
Newport Utilities	TUNet SaaS				Mesh Network	Closed	Utility
Xcel Energy					Mesh/WiMAX to Fiber	Closed	Utility
Florida Power & Light	Itron SaaS				FAN: Mesh	Closed	Utility
City of Tallahassee					Mesh to Cellular & Ethernet/Fiber	Closed	Utility
American Municipal Power	ElectSolve Saas (MDMS)				Mesh to Cellular	Closed	Utility
Grayson-Collin Electric Coop.		Itron NaaS	Itron NaaS		Cellular-only	Closed	Procured aaS
Puget Sound Energy	L+G SaaS	L+G NaaS	L+G NaaS		Mesh to Cellular	Closed	Procured aaS
EPB Chattanooga					Fiber	Closed	Utility

Note: general direction based on public information and primary market research

Definition of Terms:

- Metering coordinator: responsible for metering services (installation, maintenance, etc.) and contracting with telecom providers for network services
- Meter asset/metering provider: owns the meter (typically a financial entity); also provides installation and maintenance services or contracts to other entity

Legend: Utility Owned & Operated | 3rd Party Owned & Operated | Unknown, information not available

Figure 7.4: Market Research Inventory of Shared AMF Ownership Models

	Back Office IT (MDMS, Head-end)	WAN	FAN	End Devices	Telecom Model / Architecture	Shared/Closed Network	Own/Operate Network
UK Utilities	DCC (CGI)	DCC (Telefonica & Arqiva)	DCC (Telefonica & Arqiva)	Meter asset provider	Mesh to Cellular & Long-Range Radio	Shared (Gas & Electric)	3rd Party
Australia Electric Utilities		Telecom providers	Metering coordinator	Metering provider	Mesh to Cellular	Shared	3rd Party
SoCalGas		Verizon / AT&T			Mesh to Cellular	Shared (Gas & Water)	Mixed
Montana-Dakota Utilities	Itron SaaS				Mesh to Cellular	Shared (Elec. & Water)	Utility
New Zealand Electric Utilities		Telecom providers	Metering coordinator	Metering provider	Unknown	Shared	3rd Party
ComEd	Itron SaaS (head-end)				Mesh to Cellular	Shared (Elec. & Water)	Utility
Enel					Fiber	Shared (Telecom Co.'s)	Utility
Kuwait Ministry of Elec. & Water		Zain telecom	Zain telecom		Unknown	Shared	3rd Party
VELCO					Fiber	Shared	Utility

Note: general direction based on public information and primary market research

Definition of Terms:

- Metering coordinator: responsible for metering services (installation, maintenance, etc.) and contracting with telecom providers for network services
- Meter asset/metering provider: owns the meter (typically a financial entity); also provides installation and maintenance services or contracts to other entity

Legend: Utility Owned & Operated | 3rd Party Owned & Operated | Unknown, information not available

7.3 Consideration of Shared Services Opportunities

In the U.S., there are a limited number of shared AMF/AMI networks between utility entities, with the more prevalent model including a larger IOU that owns its communication network and a smaller utility or municipality (often restricted to gas and/or water) that leases bandwidth. Examples of such shared networks are described below:

- Commonwealth Edison Company ("ComEd") announced a pilot with American Water (of Illinois), leasing its existing AMF network. Each entity owns and operates its respective electric/water meters and back-office IT systems but shares ComEd's communication infrastructure. American Water had to install vendor-specific communication modules for its water utilities to use ComEd's FAN network.

- Southern California Gas Company ("SoCalGas") also shares its AMF network with the Los Angeles Department of Water & Power ("LADWP") and the City of Santa Monica's water department. SoCalGas owns and operates its own head-end system (using Aclara technology) while the water entities use an Aclara-hosted and operated head-end (SaaS).

- The City of Bismarck, North Dakota's water department used a public-private partnership to enter a contract with Montana-Dakota Utilities ("MDU") to access its AMF communication network. Though MDU manages the entire AMF communications system ("FAN/WAN"), Bismarck had to upgrade its water metering communication modules to access the shared network.

The Company's AMF proposal includes a commitment to leverage the AMF solution over time to integrate other end-point sensory devices that provide additional value. The opportunities to leverage the AMF solution for additional Company-owned devices and use cases are less complex compared to integrating third-party devices on a shared network. The complexities of shared networks include cybersecurity, data privacy risks, and usage coordination including service-level agreements ("SLAs") for availability, reliability, and traffic prioritization on the network. As an indication of the complexity, all but one of the domestic and international shared networks analyzed are shared between regulated entities. In addition, the costs to secure the data and develop robust interoperability requirements could potentially be large and eliminate the benefits of cost-sharing or new revenues. Based on these factors, the exploration and evaluation of network sharing opportunities is a significant undertaking that requires a careful and comprehensive effort between the Company and third parties. The Company will continue to monitor developments in other jurisdictions to leverage industry learning for potential shared-network opportunities.

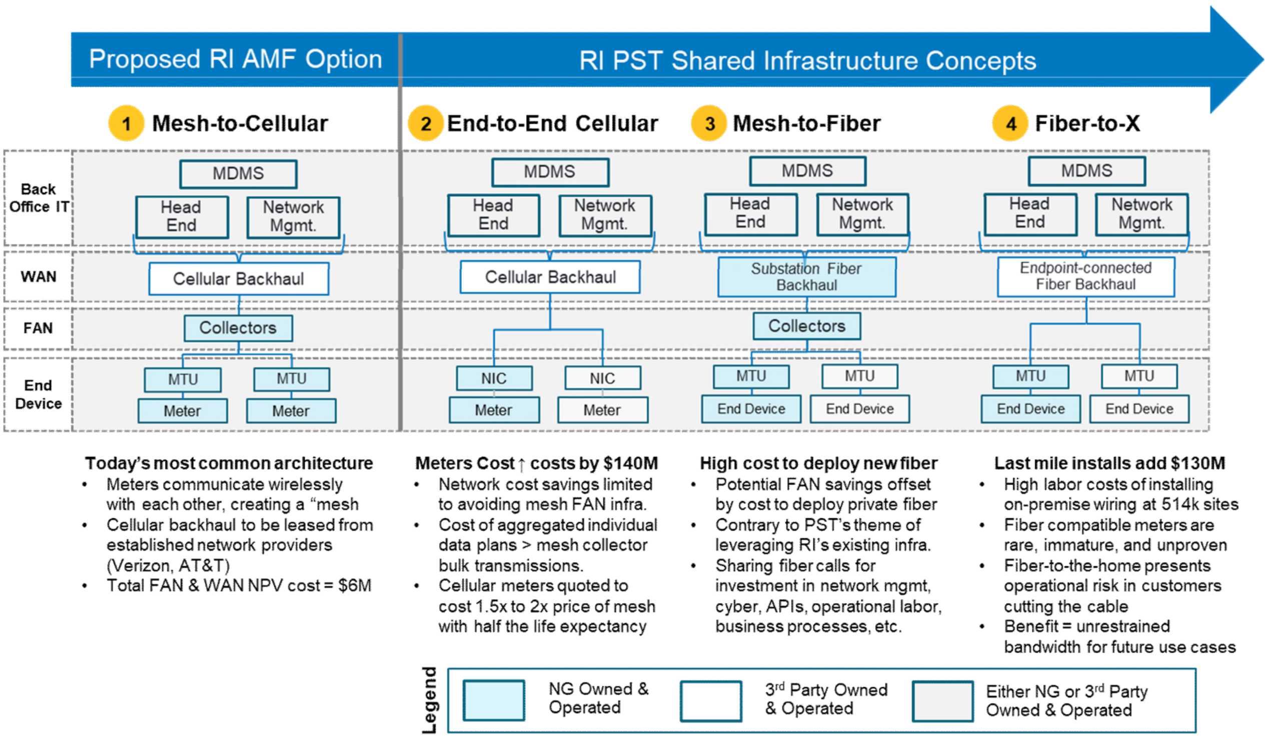
7.4 Consideration of Telecommunications Infrastructure Alternatives

The alternative business model assessment also considered the broad concept of a statewide shared network ("SWSN") from its impact on the Company's approach to AMF technology architecture, the various players, and performance requirements of Rhode Island participants. The assessment considered several key recommendations from the PST Phase One Report including:

- Consider leveraging existing infrastructure for next-generation networks;
- Explore synergies in connectivity needs between the Rhode Island Energy and the public-infrastructure sectors;
- Understand potential impacts to Rhode Island of different approaches to a SWSN; and
- Consider cost savings opportunities to AMF through network partnerships.

With respect to the AMF plan, which includes a private mesh FAN and public cellular WAN, three alternative SWSN telecommunication technologies were compared, including end-to-end cellular, mesh-to-fiber, and fiber-to-x (meter or home). The alternatives are depicted in Figure 7.5, along with a summary of the quantitative and qualitative findings of the assessment.

Figure 7.5: SWSN Technical Options Cost Comparison



Mesh-to-Cellular (Utility-Owned FAN, Third Party-Owned WAN): This is the most common AMF architecture, particularly for large IOUs, and is proposed as the Company's AMF strategy. In this model, meters communicate wirelessly with each other, creating a "mesh" that connects to field-deployed (pole-mounted) collectors that transmit bulk meter data to the utility's back-office over a cellular backhaul. Under Rhode Island Energy's proposed architecture, cellular backhaul would be leased from established network providers such as Verizon and AT&T. However, Rhode Island Energy may consider moving towards a Company-owned private network for backhaul as a part of future operational telecommunications processes. There are potential savings from the following:

- **WAN Avoidance**: The cost of leasing backhaul/backbone bandwidth from an SWSN compared to the cost of leasing from the current network providers Verizon and AT&T.
- **FAN Avoidance:** The cost of enabling direct connections to SWSN infrastructure and thus eliminating the need for FAN collectors.

The findings of the assessment conclude that while very modest savings may be possible in telecommunication costs by using the SWSN, the enabling AMF metering and operations solution costs would increase significantly. As such, the SWSN alternatives analyzed are expected to lead to overall negative impacts on the Company's total cost of the AMF solution.

End-to-End Cellular (Third Party-Owned FAN & WAN): Under the current AMF strategy, Rhode Island Energy is not planning to use cellular technology to provide meter communications because the RF network will provide complete coverage of the service area. Therefore, evaluating the option of leasing cellular backhaul/backbone bandwidth from a SWSN is not relevant. If it was relevant, potential network-related cost savings would be limited to avoiding the mesh FAN infrastructure. Such potential savings are outweighed by the added costs of cellular meters, as well as the increased costs of individual end-point data plans compared to bulk data transmission in a mesh-to-cellular approach. These findings are supported by the following data:

- Cellular meters are quoted to cost 1.5 to 2 times the price of the mesh alternative and have half the life expectancy (i.e., 10 years).
- The aggregate cost of individual data plans for meters is expected to be significantly higher than bulk data plans of collectors in a mesh-to-cellular architecture.

Mesh-to-Fiber (Utility-Owned FAN & WAN): The third approach would leverage the Company's established and future transmission and sub-transmission fiber network as part of the backhaul/backbone to a mesh-to-fiber strategy. Given that fiber is currently deployed at approximately 6% of substations, the Company would be required to further invest in developing its private fiber network to connect all mesh collectors.

The Company believes this approach does not fully leverage the State's existing infrastructure. Before PPL can lease bandwidth as a participant in a SWSN, considerable investment in network management, cybersecurity, supporting infrastructure, application programming interfaces ("APIs"), operational labor, business processes, etc. would be required to its application-built private fiber network.

Fiber-to-X: (Third Party-Owned WAN): Even though Rhode Island already has substantial fiber-to-home infrastructure deployed to 84.2% of residents,[40] considerable last-mile investment would still be required if Rhode Island Energy were undertake an end-to-end fiber approach to AMF regardless of if it were a private or shared network. In addition to the labor costs of installing on-premise wiring at all metering locations, the following are other factors to consider:

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[40] *Rhode Island Internet Coverage & Availability in 2022*, broadbandnow.com/rhode-island.

- Fiber compatible meters are extremely rare, immature, and unproven in today's market.
- Assuming that fiber termination points are conveniently located near meter sockets, additional infrastructure, and installation labor would be required above and beyond the basic meter swap.
- Physical fiber-to-the-home connections present an operational risk in that customers cut the cable resulting in additional reconnection costs. Similar to the approach described above, leasing bandwidth as part of a SWSN will require considerable investment in network management, cybersecurity, supporting infrastructure, APIs, operational labor, business processes, etc.
- A benefit to such an approach would be practically unrestrained bandwidth for any evolving or future use cases that generate larger data sets (although this is not currently forecast or cautioned by meter vendors).

Although the opportunity to partner with network providers, municipalities, cooperatives, and non-profits to create a SWSN exist, the potential technology solutions are not cost-effective option. In addition, major challenges exist with respect to the formation of a SWSN, including high costs, lack of technological advancements, and regulatory enablement. As these factors evolve in the future, so can the Company's consideration of its role in a SWSN.

Section 8

SECTION 8: AMF IMPLEMENTATION PLAN

This section describes the AMF implementation schedule, approach to vendor selection, managing with a Project Management Office, key deployment activities, and project governance plans.

This Section coupled with Attachment D addresses deployment details and the length (duration) of meter deployment. Rhode Island Energy is proposing a three and a half year, phased AMF deployment schedule, as shown in Figure 8.1.

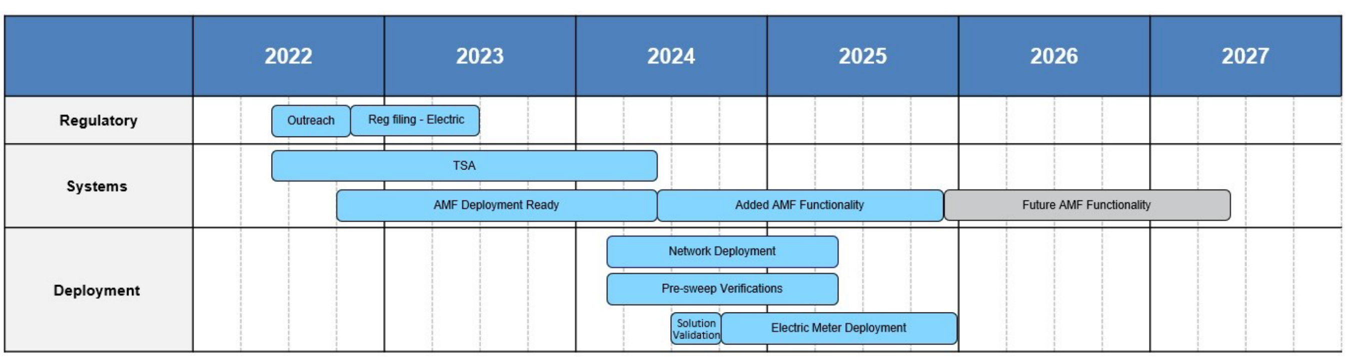
AMF deployment is a complex, integrated, multi-year technology project that will deliver significant benefits for all stakeholders - most importantly, Rhode Island Energy customers. The plan, processes, and practices that follow are based on PPL's experience, the Company's previous work while under National Grid ownership, and industry best practices - all adjusted given Rhode Island Energy's unique infrastructure and systems, Rhode Island's most current energy regulations, as well as their future vision of the electric grid and customer needs and expectations.

This project implementation plan is logical in flow, realistic in terms of timelines and deliverables, and based on the learnings of dozens of utility industry rollouts of advanced technology products and programs over the last decade. When implemented, this advanced meter functionality will deliver state-of-the-art technology to Rhode Island Energy and its customers.

8.1 Project Timeline

To implement AMF, Rhode Island Energy proposes a three and a half (3 ½)-year implementation plan and project timeline as shown in Figure 8.1.

Figure 8.1: AMF Project Timeline



The AMF Project Timeline is comprised of three overlapping and overarching functions – Regulatory, Systems, and Deployment – each of which is necessary and integral to success, briefly described as follows:

Regulatory

The AMF Project commenced in earnest several months ago with the regulatory preparatory work to file this Business Case with the PUC. The "Outreach" to the PST Advisory Group (see Section 1.6 and Figure 1.6) was to present the AMF Business Case and seek feedback from the AMF/GMP Subcommittee of the PST Advisory Group. These stakeholder members represent a broad spectrum of interests ranging from environmental and clean-energy groups to low-income, community, and business interests, as well as non-regulated power producers ("NPPs"). Together, these stakeholders assisted in the development and review of the AMF implementation strategy and work-plan schedule.

The "Reg Filing – Electric" represents the months of research, analysis, planning, and documentation of all the activities required to prepare and submit this Business Case to the PUC for approval with an anticipated PUC ruling in the 2nd quarter of 2023.

Systems

Systems work associated with the TSA and the functionality to be "AMF Deployment Ready" has commenced concurrently with this filing. As discussed in Section 6, "AMF Deployment Ready" includes system integration work that is core and essential to exchange AMR meters with AMF meters while maintaining billing and it enables increased customer visibility of usage data so customers can better manage their energy consumption as soon as they receive their new meter. "Added AMF Functionality" will provide enhanced functionality and applications for both customers and Rhode Island Energy, and "Future AMF Functionality" will incorporate learning and efficiencies for further application development. The AMF functionality roadmap is displayed in Figure 6.1 of Section 6, and descriptions of the associated functionalities are detailed in Figures 6.2, 6.3 and 6.4.

Deployment

The Deployment function is comprised of a series of activities that represent the bulk of the physical deployment activities and customer premise work to be performed including pre-sweeps, the installation of the RF mesh communication network, and meter deployment.

Pre-sweeps are the first activity in the meter deployment process constituting a detailed physical review and gathering of customer premise meter information in advance of the AMF meter installations. Pre-sweeps proactively collect information to identify issues in order to make the meter installation as efficient and effective as possible. Issues may include meter obstructions, meter base repairs, and other safety, power quality, and electrical issues that need to be resolved and/or repaired prior to new meter installation and activation.

"Network Deployment" represents the design, planning, and installation of the RF Mesh Communications Network in each sector in advance of actual meter installations. The communications network will be installed, tested, and required to meet specific communications requirements and criteria prior to the start of new AMF meter installations. Geographic segments of the network will be installed and connected to the necessary back-office systems to verify communications from installed network devices and the transfer of other critical data before advancing to the next geographic segment. Once meter installations begin in a particular sector, the network optimization in that sector will continue as the RF mesh fully forms.

"Electric Meter Deployment" represents the installation of new AMF meters which is preceded by a "Solution Validation" phase. This Solution Validation phase will start during the 3rd Quarter of 2024 and will include a total deployment of up to approximately 500 meters. The goal of Solution Validation is to test the new AMF solution from end to end to ensure the entire system is working as designed, prior to full deployment of electric meters.

Customer engagement throughout and between these activities will be significant, requiring coordination among internal work groups and frequent external communications to customers, public officials, and others as discussed in Section 9 - Customer Engagement Plan.

8.2 Key Deployment Activities

This section expands upon the deployment function described above, providing further detail on pre-sweeps, network design and deployment, solution validation, and full electric meter deployment, as well as other key deployment activities including "stabilization period" and "meter replacements and new construction." Each of these key activities is summarized and explained below. Additionally, a comprehensive, detailed deployment plan has been developed and is attached to this filing as Attachment D. It describes the deployment plan and activities in greater detail and will serve as a guide for execution by the Program Management Office and the various Workstream Teams as part of the overall Project Governance Model as depicted in Figure 8.2 below:

Pre-Sweeps for Meter Deployment

Pre-Sweep verifications will be performed several months prior to the installation of new meters. This work will permit Rhode Island Energy to gather general information on customer meters, as well as identify and address any power quality or safety issues that are identified, including any meter base repairs that are needed. Rhode Island Energy will perform any repairs needed with qualified contractor personnel. All information identified through the pre-sweep process will be used to update the customer service database to facilitate meter deployment and perform safe meter exchanges.

Customers will be informed of approximate dates of pre-wweeps and will not need to be home if their meters are located and accessible outside of their home. Customers will also be provided with information on how to schedule an appointment if they prefer. The vendor performing the pre-sweep will make several attempts to complete the pre-sweep if they are unable to access a customer's meter (e.g., inside meter locations) on the first attempt.

Pre-sweep personnel will carry proper identification and have company logos on their vehicles. All customers will receive a letter in the mail prior to their pre-sweep review. The letter will include the Rhode Island Energy and other associated companies' call center phone numbers that customers can utilize if they have questions about the pre-sweep process or if they would like to schedule an appointment. Every attempt to perform a pre-sweep review will be documented in the Company's Customer Service System ("CSS").

Network Design and Deployment

Communication network design and deployment starts with a power system and telecom engineering assessment. The design process utilizes site surveys for the network equipment that constitute photographs of the terrain coupled with receiver noise floor and interference testing information. Implementation of the network includes installation of pole structures, network high-capacity gateways followed by routers, and network testing. LTE/cellular will be used to backhaul information from the gateways to the IT platforms for assessment and processing. The communication network design and deployment will be completed before any installation of meters during the Solution Validation phase for the first deployed sector and before meter deployments in sectors thereafter. A timeline of this process as well as a map of equipment deployment can be seen in figures 8.2 and 8.3 respectively.

Figure 8.2: Two-Way Communication Network Staging and Deployment

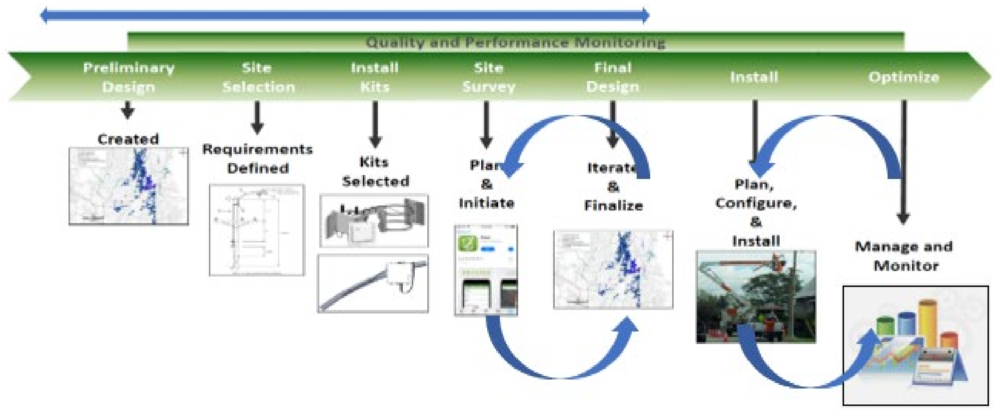
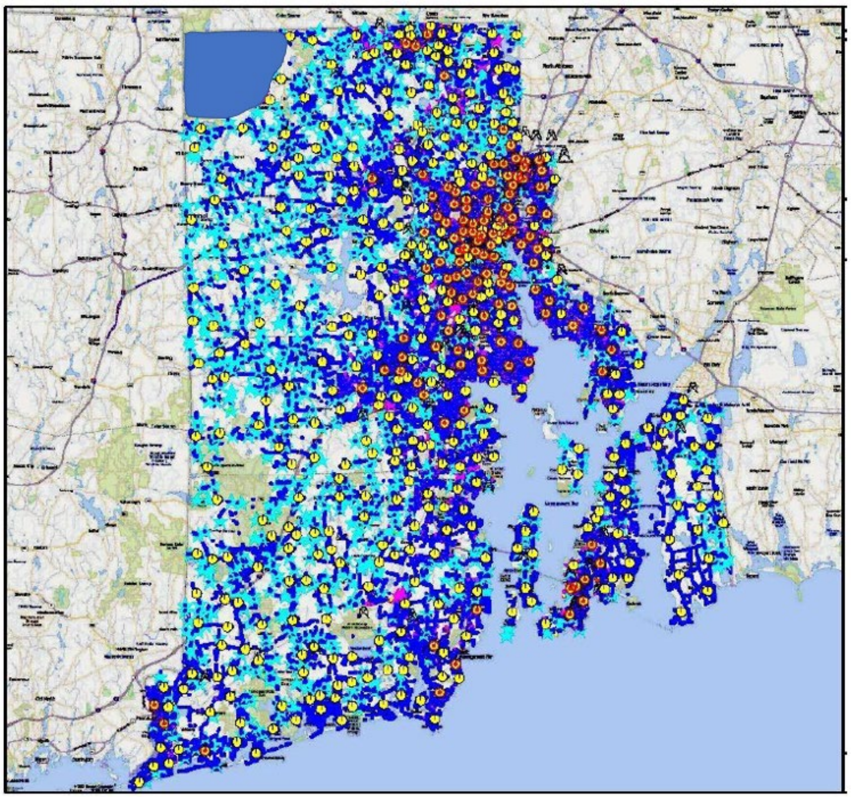


Figure 8.3: Network Deployment Map



Network Equipment		Quantity
High-Capacity Gateways (3 radios)		**109**
Standard Capacity Gateways (1 radio)		**402**
RF Routers		**1280**

Rhode Island Energy's network design incorporates lessons learned from PPL's Pennsylvania deployment resulting in more network equipment to support endpoints, dedicated gateway pole structures and a more resilient network design (compared to the design approach proposed by the Company while under National Grid ownership). As a result, Rhode Island Energy is bringing greater antenna height to mount more antennas to reduce receiver "de-sensing" and more redundancy in the system so there is less impact to network performance if equipment fails. To the extent that there is an alarm for the network it will be acknowledged and managed by the PPL Fusion Operations Center (24x7x365) which features automation-based ticketing for gateway/router issues that occur across all PPL jurisdictions.

Solution Validation

The purpose of the Solution Validation phase will be to use the processes and tools planned for full deployment with a limited meter population and slower deployment rate as well as to further optimize the RF mesh network. Installing a limited number of meters during this phase will allow for fine-tuning of the meter and communications network following the field testing of equipment and systems. Solution Validation will only be initiated in a geographic sector where a business-approved pre-sweep verification has been completed.

The strategy for the Solution Validation phase will identify specific aspects of the deployment plan to be optimized. These will include geographic area deployment plans, cross-dock, and warehousing strategy, use of deployment vendor field tools, work management process optimization, safety program compliance, hard-to-access customer processes, and other aspects of the deployment. Each of the identified optimization areas will be measured as appropriate, and the Company will ensure that the Solution Validation results are successful before commencing with Full Deployment. This phase will also include testing of business processes such as billing and remote connect/disconnect functionality.

Full Electric Meter Deployment

The full deployment of electric meters will begin following the Solution Validation Phase and will continue through the 4th Quarter of 2025. To fully deploy the remaining approximately 524,677 electric meters in the Rhode Island Energy service territory will require a gradual monthly ramp up to an average deployment rate between 35,000 – 40,000 meters/month, followed by a gradual ramp down in the last couple of months. Network and communications infrastructure (gateways, backhaul equipment) will be deployed ahead of the meter hardware. This will allow newly installed meters to become operational on an existing communications network and will mitigate potential communications issues.

Processes for deployment will rely on the tools offered by the chosen deployment vendor, industry best practices, and PPL's experience in Pennsylvania and Kentucky with previous large projects of this nature. Rhode Island Energy's detailed deployment plan (Attachment D) addresses all major components, such as:

- *Deployment Vendor Contracting Strategy*: Processes for development, execution, and management of deployment vendor contract. This will include a strategy for managing vendor terms and accountability structures in the contract, as appropriate.
- *Geographic Deployment Plan and Sector Selection*: Location-based deployment plan for electric meter deployment across the Rhode Island Energy service territory. This also will align geographies to the timing of deployment during the Solution Validation and Full Deployment phases.
- *Regional Readiness and Transition*: Pre-deployment strategy at the Rhode Island Energy regional operations level to ensure preparedness for incoming deployment.
- *Sector Acceptance Criteria*: Checklist for activities required prior to approving deployment in a particular sector, i.e., certain level of read rates, mitigation of all communication issues, etc. This effort will include a strategy for handoff of the solution on a sector-by-sector basis from the deployment team to operations.
- *Supply Chain and Logistics*: Procurement strategy and logistics, including strategies for location of cross-docks and warehouses, mobile project management requirements, and movement of hardware across the service territory.
- *Workforce Management Strategy*: Management of deployment contractors and personnel including badging, training, on-and off-boarding, safety procedures.
- *Risk Identification and Mitigation Strategy*: Strategy to manage risk associated specifically with deployment. Rhode Island Energy will address potential power quality and safety issues with customer-owned meter bases during deployment.
- *Communication Network Optimization Strategy:* Strategy for deploying meters that builds out the RF mesh network through volume and in a manner that supports meter-to-meter communications and optimization.
- *Safety Plan*: Plan describing safety policies and procedures required by all deployment personnel in alignment with the Company's existing safety requirements.

Stabilization Period

Following the completion of electric meter deployments in each sector, the system will enter a stabilization period of several months whereby fine-tuning of the mesh network and back-office systems occurs. This time will also be used to deploy any final systems enhancements or upgrades prior to full operationalization.

Finally, this time will also be used for refinement of business processes impacted by the AMF technology implementation, as well as to address any meters in hard to access locations or difficult-to-reach radio frequency environments where the RF signal may not propagate effectively.

Meter Replacements and New Construction

Rhode Island Energy will replace existing AMR meters for existing customers and install new AMR meters for new construction as necessary until the new RF mesh network has been extended to the geographic area where the request is generated from. If Rhode Island Energy were to install the new AMF meters that communicate via the RF mesh network, it would be impossible to read these new meters remotely because the communication network had not been installed yet.

8.3 Back-Office Systems Deployment and Integration

Back-office systems deployment and integration consist of a series of systems technologies that are critical for managing data and delivering AMF functionality as well as business integration and testing as described below:

Systems Technology

The work required here includes the IT design, build, integrate, test, and implement phases for meters, the RF mesh network, the network operating center (PPL's Fusion Operations Center), the MDMS, billing system, and other supporting technologies. This new IT infrastructure will be required to ensure that critical information captured by the new AMF meters is carried to the appropriate systems for billing, settlement, validation, analytics, and other core business functions.

The IT activities will follow a staged functionality approach whereby systems will be built and released in stages over the deployment period. This staged approach provides a method for risk mitigation and ensures effective and efficient operations. The IT timeline is being driven by the requirement to ensure the existing AMR meters are transitioned and sourced from the new MDMS, as well as the requirement for the IP-based RF mesh communication network installation in advance of the meter deployment schedule including the Solution Validation Phase, which is critical because it is used to test the final versions of the IT systems and deployment tools. Therefore, before full deployment can commence, these IT systems must be in place and meet all required performance criteria.

The IT system creation process will use the Agile methodology for software development including definition, discovery, design, development, deployment and debrief. Testing of IT systems will follow a similar approach beginning with unit (component) testing of specific functionality and features, then functional testing for processes around multiple features, then integration testing across systems and of end-to-end communication functionality, followed by User Acceptance Testing ("UAT") and security testing.

The AMF system requirements will be factored into the systems' design and integration requirements. Examples of anticipated functionality include creating an integrated Customer Experience ("CX") omni-channel portal for customers that will be augmented by the new AMF meters. In addition to reliably supporting billing as it transitions from AMR drive-by collection to AMF fixed network, at the end of the TSA, Rhode Island Energy plans for its customers to migrate to the PPL website which relies on AMF usage data. At this point, the PPL applications will become available offering a wide variety of capability such as the ability for customers to view historic consumption, utilize Green Button capability for customers to share their data with vetted third parties, receive high bill alerts, views portfolios if customers are responsible for multiple facilities.

Systems Testing

Testing begins with requirements and includes the system vendors, the system integrator, and PPL. The requirements, along with the architecture and security plans, drive the implementation of the systems and the system interfaces, which in turn drives the test plans and test scripts. The following types of testing are conducted to ensure proper functioning of systems end to end:

- *Unit (Component) Testing* – low level testing of specific components of software in relative isolation to ensure the components work as designed, before proceeding to higher level testing.

- *Functional Testing* – testing the functionality delivered in each system meets the requirements. Many functions are required business capabilities. User roles and their capabilities and limitations are tested here.

- *Integration Testing* – verify that requirements are met both within and across systems, e.g., passing billing determinants to the customer system. Initially, this is functionality tested at low data volumes with selected data to exercise the interface and grows to high data volumes with the full complement of data that is required in the production system.

- *System Testing* – verifies end-to-end functionality, intentionally including the meter communications network and meters, operating with firewalls properly configured, under full system load of users and batch job processing, along with server and database performance monitoring to ensure expected runtimes and system responsiveness are achieved.
- *User Acceptance Testing* – is the last major testing effort that must be successful before moving to production use of the systems, interfaces, and communications networks. It includes many of the tests done in earlier testing with an emphasis on the systems working end to end while users accomplish business functions.

All phases of testing include the reporting and correction of defects and issues before proceeding to more advanced testing and environment promotions. Similarly, security testing occurs in many of the testing phases (who has what access, verify access is appropriate to role, user id and password policies are enforced, non-user accounts are properly established and managed, system to individual meter communications is encrypted and only usable by the endpoint meter, meter alerts for tampering or unexpected activities are reported to users, etc.).

8.4 Vendor Selection and Management

Rhode Island Energy will require external assistance from vendors with extensive experience and/or specialized services to meet the resource needs. Pre-established PPL AMF contracts and relationships that can be leveraged by Rhode Island Energy will be executed through several sole-source contracts with such vendors to derive efficiency and scalability. This approach is consistent with industry best practices and will expedite the contract execution process and the delivery of services.

Rhode Island Energy will be leveraging many existing strategic partnerships that have been established through AMF deployments in both Pennsylvania and Kentucky. The most recent application in Kentucky will serve as a good basis for cost comparisons.

Vendors will be needed for project management, material and equipment, and IT systems development, implementation, and/or integration with existing systems. Contracts may be issued for multiple aspects of the project including but not limited to the AMF system including meters, network infrastructure (communications), and head-end technology; meter data management and billing systems, the Customer Portal, meter deployment/installation, Program Management Office ("PMO"), and an overall System Integrator ("SI").

When the Company selects vendors through the execution of contracts, the responsibility for the day-to-day management of vendors will lie with the AMF Project Team. Vendor-related processes such as onboarding and offboarding of vendor personnel, processing of vendor invoices, contract management, and change requests will also be performed by members of the PMO.

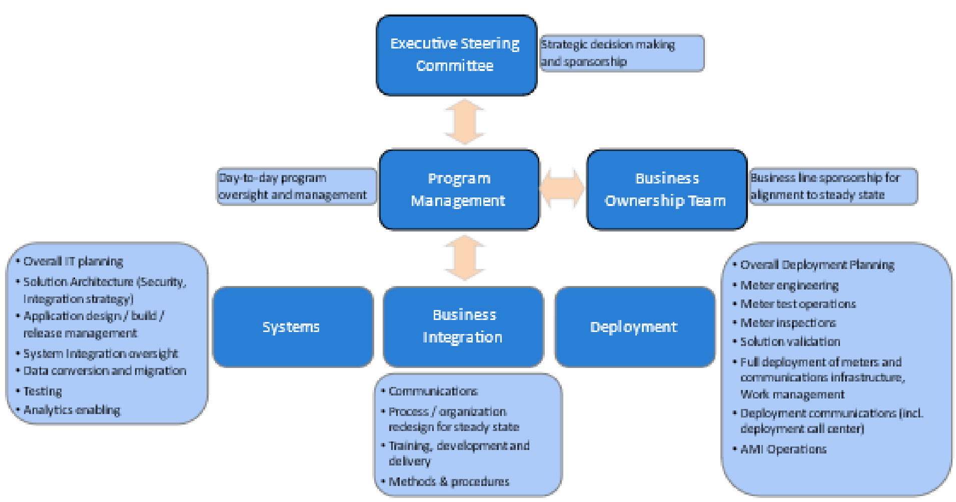
8.5 Project Governance

Rhode Island Energy will use an AMF Project Governance Model to define the structure, processes, methods and interfaces to manage and oversee the AMF Project. It provides an organizational framework to enable the completion of a successful deployment and overall implementation of this state-of-the-art advanced metering functionality. It also ensures that responsibilities, decision-making authority, and processes for the project are clearly defined. Lastly, it describes the process for issue resolution and outlines a leadership meeting and communication structure.

AMF Project Governance Model

As shown below in Figure 8.4, the AMF Project Governance Model consists of an Executive Steering Committee, PMO, key Workstream Teams including Systems, Business Integration, and Deployment, all supported by line organization business owners – the Business Ownership Team.

Figure 8.4: AMF Project Governance Model



Executive Steering Committee

The Executive Steering Committee is a strategic decision-making group and project sponsor. This committee's purpose is to provide overall governance and approval of all major policy, strategy, and financial decisions. Their ongoing responsibilities are to ensure organizational goals are aligned, necessary resources are assigned, and organizational issues are resolved to ensure successful project completion and execution. The Executive Steering Committee ensures expectations are understood by the organization and those who are assigned from their organization to participate on working teams. This committee meets quarterly and will include representation from senior leadership and key AMF Project Team members.

Program Management Office ("PMO")

The Program Management Office is the AMF project leadership team whose purpose is to plan and execute the project in its entirety, including day-to-day program oversight and management. They are responsible for the successful deployment of all infrastructure and implementation and/or migration of all IT systems. Expected outcomes include execution of all work activities such that expected deliverables are within scope, on time, and on budget, achievement of strategic and operational objectives, and the transitioning of all outstanding work items to ongoing operations upon project completion and closeout.

The project team will be comprised of dedicated, full-time internal personnel from various utility functions integral to the project. It will also include subject matter experts external to the PMO that can provide ongoing support and/or provide specific and finite services and value. It will be led by the AMF Project Team Leader who is expected to champion the project vision, manage all resources and schedules including Workstream Teams, and be responsible for successful development of the overall project.

The PMO will also manage all administrative functions of the project including but not limited to creating agendas, maintaining meeting minutes, tracking schedules and milestones, and monitoring how the project is progressing compared to the plan.

Business Ownership Team ("BOT")

The Business Ownership Team is the line leader representing ongoing operational functions within the organization. They are critical to the successful implementation of AMF because they ensure the ongoing operation of the business during the deployment of meters, network, and systems infrastructure. These BOT works collaboratively with the PMO and Workstream Teams to understand deployment activities and the impact they will have on operations, and consequently, prepare for and ensure business continuity and work to mitigate and/or eliminate customer impacts. This committee meets monthly and will include leadership representation from all departments impacted from the AMF deployment.

Workstream Teams

There will be three Workstream Teams including a Systems Team, a Business Integration Team, and a Deployment Team. They will represent the bulk of people assigned to the project as they carry out the primary day-to-day work activities of the project. These teams will be staffed with a variety of full-time, internal resources based on the skills needed to perform the work. The overall staffing will be based on the respective work volumes required. The teams shall be staffed with employees from Planning, Engineering, Operations, Customer, Information Technology, Legal, Regulatory, and Corporate Communications - as these represent the primary groups within the utility that possess the management skills, experience, process knowledge, and subject matter expertise to effectively execute the required work.

The Systems Team will incorporate work activities associated with planning, solution architecture, application design/build/release, system integration, data conversion and migration, testing, and analytics. The Business Integration Team will incorporate work activities associated with communication, process redesign, training development and delivery, and methods and procedures. The Deployment Team will incorporate work activities associated with planning, engineering, pre-sweeps, solution validation, full deployment of meter/communication network, work management, deployment communications, AMF operations, and meter testing operations.

Team leaders shall be appointed for each workstream team and will be key direct reports to the AMF Project Team Leader. Charts will be developed for the working teams to ensure roles, accountability, leadership, and communication are clearly defined and understood. Their core responsibilities include developing and executing the detailed workstream activities, managing scope in coordination with the PMO, and tracking progress to plan.

Vendor Support

Multiple vendors with specific and requisite expertise will support the AMF Project based on the products and services they are providing by contract. As such, all major vendors will be part of and accountable at a regular cadence of meetings as part of the governance structure. These may include:

- *Strategic Management Consulting* – firm responsible for providing industry expertise to facilitate and document the AMF regulatory filing and the end-to-end AMF strategic plan.

- *IT System Integrator* – primary IT firm responsible for the development, integration, and implementation of all new and existing management and business information systems.

- *Infrastructure Deployment* – firm responsible for PMO functions including planning, tracking, and monitoring of deployment activities and performance.

Issue Resolution Process

The Issue Resolution Process establishes a means to bring visibility to unresolved and/or critical issues so they can be appropriately managed. It provides a mechanism to log issues and assign owners and associated actions for resolution. This process ensures that decisions are made in an expeditious and timely manner to prevent undesirable impacts to the project, and that appropriate parties are informed and involved in critical decision-making.

The PMO will prepare a summary of weekly progress and issues for escalation. Any issue that requires escalation will be documented in the Issues Log. The Issue Log will be reviewed weekly by the AMF Project Team Leader and his/her direct reports where resolution and/or further escalation will be determined.

Leadership Meetings/Communication Structure

Figure 8.5 is a governance and project management tool demonstrating how the AMF Project Team Leader and associated teams will develop a cadence to organize and communicate.

Figure 8.5: Leadership Meeting/Communication Structure

Event/Forum	Purpose	Frequency	Participants	Owner(s)
Huddles/Stand-Up Meetings	Progress Reports, Issue Resolution	Daily	Workstream Teams, PMO	Workstream Team Leaders, PMO
Tactical Meetings – Systems, Bus. Integration, Deployment	Planning, Progress Reports, Issue Resolution	Weekly	AMF Project Team Leader, Workstream Team Leaders, PMO	AMF Project Team Leader
Performance Review w/Business Ownership Team	Full Project Performance Review, Course Correction	Monthly	AMF Project Team Leader, Workstream Team Leaders, PMO, BOT	AMF Project Team Leader
Executive Update	Executive-level readout of AMF Program Status	Quarterly	Executive Steering Committee	RI President & COO

Section 9

SECTION 9: CUSTOMER ENGAGEMENT PLAN

This section describes the phases of customer engagement throughout the life of the project, how customer concerns will be addressed, and the customer experience enabled with the Customer Portal. Examples of communication that is planned for various aspects of engagement, including opt-out, is provided.

Customer engagement is a top priority for ensuring that the Company's AMF investments are fully leveraged and utilized by customers. The Customer Engagement Plan ("CEP") will educate, engage, and empower customers to maximize these benefits. During its initial stages, the CEP is designed to ensure that stakeholders are kept informed about program status and implementation schedule for the deployment of the RF Mesh network and installation of advanced meters. Further along, the CEP strategy ultimately aims to maximize the benefits available from deployment of the AMF technology platform. The Company recognizes the importance of engaging all market segments, and the challenges in reaching all customers. To that end, the plan provides for customized approaches to the various market segments including low income, non-English speaking customers, elderly, high usage customers, customers with plug-in electric vehicles, and customers with solar panels and/or battery storage units. The CEP will engage customers throughout the AMF implementation planning, installation, and post-installation processes by seeking customer feedback to adjust communication messages and channels based on customer preferences. The modes of communication that the company will use are listed below.

Rhode Island Energy will utilize a variety of communications platforms throughout the project to communicate with different external stakeholder groups. Key tactics that may be utilized to deliver program-related communications include:

- Rhode Island Energy Website – The website that gets built for the AMF project will be based on what PPL has developed in both Pennsylvania and Kentucky. The website will house all the information available about the project that a customer may need. If a customer does not find what they need or have additional questions, information will be provided as to how they can contact Rhode Island Energy to get their question answered.

- Direct Mail – Direct mailings include letters, postcards and brochures. These materials will be used to notify customers about deployment activities and provide information about the new meters and new programs and services.

- Email Notifications – Email notifications may be utilized to notify customers about deployment or to provide information about new programs and services.

- Phone Calls – Phone calls, including automated voice messages, can be used to remind customers about their meter replacement or to schedule an appointment for a meter replacement.

- Handouts – Handouts include door hangers, brochures, fliers and fact sheets. Handouts can be downloaded off the website or mailed to customers upon request.

- News Releases and Media Outreach – State and local news sources can be utilized to notify communities about deployment or other major project milestones.

- Social Media – Social media can be utilized to better understand customer sentiment, obtain feedback, and communicate information about new programs and services. Rhode Island Energy will monitor social media platforms for mention about the AMF program and for specific customer inquiries.

- Video – Videos can be posted to Rhode Island Energy's website to demonstrate a meter replacement or to educate customers about how to make use of new programs and services.

Rhode Island Energy has created this CEP by utilizing what has worked in other AMF deployments and incorporated the input and feedback it has received, including feedback received by the Company when it was under National Grid ownership, and feedback from the GMP and AMF Subcommittees as part of the PST Advisory Group. Prior to PPL's ownership of Rhode Island Energy, the Company conducted multiple stakeholder meetings to discuss the CEP strategy. This feedback has been incorporated into the customer engagement and deployment plans of this AMF Business Case.

9.1 CEP Activities During Meter Installation and RF Mesh Network Deployment

The communications plan will ensure that stakeholders are kept informed about program status, schedule, and features and benefits of the new RF Mesh and AMF systems, including the new advanced meters. The overall objectives of the communications effort are to:

- Inform stakeholders about the AMF program and provide reasons why Rhode Island Energy is replacing the AMR system

- Educate customers about the features and benefits of the new AMF system and meters

- Inform stakeholders of program progress and address stakeholder concerns regarding the new AMF system and meters

- Prepare customers and community stakeholders for installations in their geographic region
- Educate customers about new programs and services made available to them
- Engage customers to participate in new programs and services that will help them better understand and manage their energy use
- Ensure stakeholders have a mechanism to provide feedback and solicit additional information about the program
- Ensure that all educational materials are available in various languages, including Spanish and Portuguese, based on Rhode Island customer demographics

The key messages that will be communicated to stakeholders and customers throughout the program are as follows:

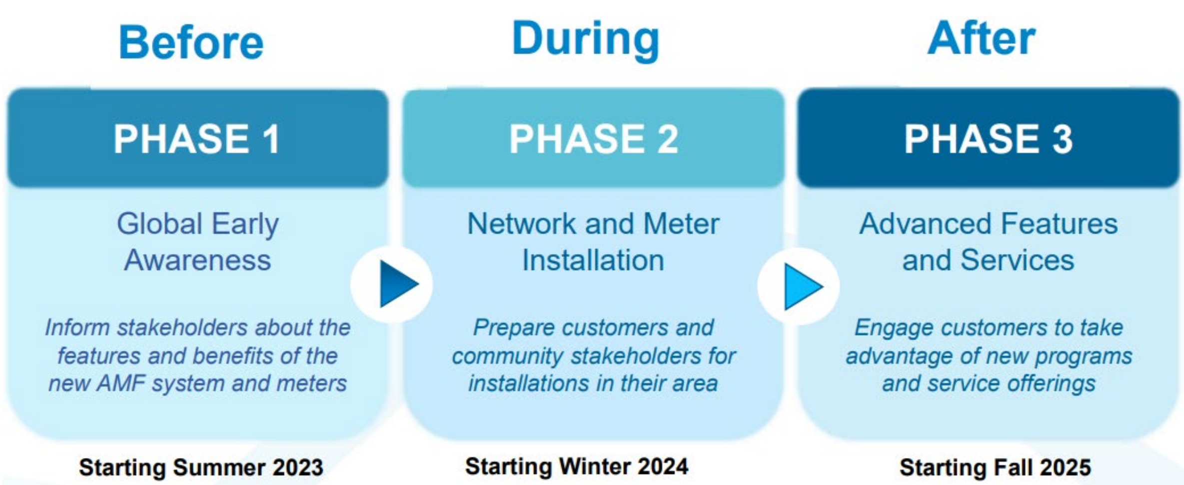
- The current meters are nearing the end of their useful lives and this project will proactively replace them.
- The replacement of current meters will give customers improved access to data that will help them manage energy use and shop for their electricity supply.
- The new meters will also improve service reliability by helping the Company to better detect outages.
- The new meters will help the Company more quickly connect or disconnect service, and thereby provide faster service to those moving into or out of homes.
- The new meters will enable future programs, services, and rate structures.
- Rhode Island Energy will carefully protect customers' information, consistent with all regulatory requirements and, to support that commitment, has developed a stand-alone customer privacy policy specifically related to the protection of meter information.
- Rhode Island Energy is committed to proactive communications with customers and other stakeholders in the period leading up to the rollout of the new meters, and to helping customers understand the benefits of the new meters once they are in place.
- Rhode Island Energy is committed to listening to and addressing all stakeholders' questions and concerns.

Rhode Island Energy will communicate and engage with a variety of stakeholder groups throughout the program. PST stakeholder updates are anticipated to be provided two times per year and an annual report will be provided.

9.2 CEP Phases of Implementation

Communications will be delivered in three phases, which may overlap, based on program life cycle and how and when stakeholders are impacted. The key communication will evolve over time as the project progresses and new functionalities become available to customers. The three phases of the communications implementation plan are summarized in Figure 9.1 and are subsequently described below.

Figure 9.1: Three Communication Phases



9.2.1 Phase 1: Global Early Awareness

Phase 1 occurs prior to the start of installation of the RF Mesh communication network and meters. The objective is to establish awareness of the plan to replace its existing AMR system and inform stakeholders about the features and eventual benefits of the new AMF system and meters. Phase 1 communications are targeted at all stakeholder groups. The key activities include:

- Establishment of a dedicated website
- Explaining the importance of smart Electric AMF infrastructure to enable customers and clean climate objectives

- Providing new meter FAQs segmented for customers, employees, and contractors
- Offering new meter brochures provided as a download on Rhode Island Energy's website that can be distributed to customers, employees, and contractors

9.2.2 Phase 2: Network and Meter Installation

The objective of Phase 2 is to prepare customers, government officials and other community stakeholders for the pre-sweeps, the installation of AMF network devices and the exchange of electric meters in their respective geographic area. Phase 2 begins with the pre-sweep process, during which crews will canvas and inspect legacy meters for the purpose of identifying potential issues with the meter exchange and to update company records to ensure the meter exchange process is efficient. During the pre-sweeps, the Company will send representatives to collect information on customers' meters to identify barriers, obstructions, and viability of the meter bases. The purpose of these activities is to document potential meter installation issues and to update Rhode Island Energy's customer service database with information in advance of meter installations to make the meter conversion process as efficient as possible. Pre-sweep communications will consist of letters mailed to customers informing them of the upcoming activities and how they will be impacted. These letters will be sent 2-4 weeks ahead of the pre-sweep activities.

The next activity that will occur in Phase 2 is the installation of the AMF communications network, which includes the RF Mesh devices. These will be installed four to six months ahead of the installation of meters in any given geographic area. Phase 2 communications start approximately one month prior to the installation of RF Mesh network devices in an area and are targeted at customers and community stakeholders. Communications regarding the AMF Network installations will start with the first installation area and will continue until all RF Mesh device installations are completed.

The final Phase 2 activity is the exchange of the legacy electric meters with new AMF meters at all premises in a geographic area. Communications associated with the meter exchange will consist of a series of letters and calls in advance of the day of the meter exchange. The Company will follow a staged process to prepare customers and community stakeholders for installations within their respective areas. Installation communications activities will occur at different times in geographic regions based on the installation schedule. Rhode Island Energy plans to communicate with local government officials and community leaders prior to beginning any field work in their respective areas. In addition, throughout the installation process, the Company will keep both the PUC and the Division informed of the status of the AMF project and any issues or concerns that may arise.

Customer notifications will occur at various AMF project milestones as summarized in Figure 9.2 and as each are subsequently described.

Figure 9.2: Customer Notification Milestones

Approximate Timing	Notification
Prior to Pre-Sweep	▪ Pre-Sweep notifications letter sent to customers
Prior to Network Device Installations	▪ Letter sent to local legislative offices and municipalities
6 Weeks Before Meter Exchange	▪ Meter exchange notification letter sent to customers
3 Weeks Before Meter Exchange	▪ Letter sent to local legislative offices and municipalities ▪ Meter exchange notification letter sent to customers
1 Day Before Meter Exchange	▪ Automated phone call / voice message to customers
Day of Meter Exchange	▪ Door knock prior to meter exchange ▪ Door hanger left at premise post meter exchange

Prior to Pre-Sweeps and Network Device Installations

Contact with Local Law Enforcement, Government Officials and Community Leaders – Prior to the pre-sweeps and installation of network devices in an area, Rhode Island Energy will contact local law enforcement, local and state government officials (elected officials, civic leaders) and leaders of community groups to inform them that Rhode Island Energy is preparing to start network deployment. This communication will occur approximately four to six months prior to meter deployment. This communication will include information about the AMF Project, the features of the new AMF system and meters, when network and meter deployments will occur, who will be performing the installations and how to access information on PPL's website. Rhode Island Energy will provide these stakeholders with a fact sheet containing FAQs regarding network and meter deployment and a copy of the new meter brochure.

Contact with the PUC and the Division – PPL will provide information to the PUC and the Division prior to the start of meter installations. Such information will include a copy of the new meter brochure, FAQs regarding meter installations and the meter replacement program and a copy of the installation schedule. This information will assist PUC and Division employees with addressing any inquiries received from customers regarding the AMF Project.

45 Days before Meter Replacement

Direct Mail Notification to Customers – Customers scheduled to receive a new meter will be sent a notification letter in the mail approximately forty-five days before their scheduled meter replacement. In addition to notifying the customer that they are scheduled to receive a new meter, this letter will provide information about Rhode Island Energy's meter replacement program, the new AMF system and meters and how to access additional information on Rhode Island Energy's website. A sample of this letter is available in Attachment F.

PPL Electric Website Update – In preparation for deployment, Rhode Island Energy's website will be updated to include information about network and meter deployment. This information includes the deployment timeline, who will be performing the installations and how to identify them, what to expect during the meter installation, specific information for medical and commercial customers and how to schedule an appointment for a meter replacement.

21 Days before Meter Replacement

Direct Mail Notification to Customers – Customers scheduled to receive a new meter will be sent a second notification letter in the mail approximately twenty-one days prior to their scheduled meter replacement. This communication will focus on the meter and meter replacement event. Key messages include the features of the new meter, what to expect during the meter replacement, who will be performing the exchange, contact information and how to access additional information on the website.

Newsletter – A news story may be included in the customer newsletter to announce the start of meter deployment in the first deployment area and provide the address of the website to visit for more information. Periodic updates regarding deployment may be included in the newsletter to announce major deployment milestones.

Contact with Local Law Enforcement, Government Officials and Community Leaders – Prior to the installation of meters in an area, Rhode Island Energy will contact local law enforcement, local and state government officials (elected officials, civic leaders) and leaders of community groups to remind them of the upcoming deployment. The

Company will provide these stakeholders with an updated meter installation schedule and FAQs regarding meter deployment.

1 Day before Meter Replacement

Automated Phone Call – The day before a customer is scheduled to have their meter replaced, Rhode Island Energy's deployment vendor will make an automated phone call to customers. Per regulations from the Federal Communications Commission, Rhode Island Energy will not make automated phone calls to customers' cell phones unless the customer has provided their consent. The phone call will inform the customer that their meter is scheduled to be exchanged within the next couple days and provide brief information about what to expect during the meter replacement and a number to call if the customer wishes to schedule an appointment.

Day of Meter Replacement

Courtesy Contact/Door Knock – Prior to beginning the meter replacement, the installer will attempt to make contact with the customer to inform them of the potential brief interruption of power. The installer will inform the customer that they are working on behalf of Rhode Island Energy. Installers will carry Rhode Island Energy contractor identification badges and have company logos on their vehicles. Installers will also be provided with copies of the new meter brochure to provide to customers that request additional information about the new meter.

Door Hanger – After the meter replacement is complete, the installer will leave a door hanger at the customer's premise that informs them of the meter replacement and provides a number to call if they have any questions or concerns regarding the meter replacement. The door hanger will direct the customer to visit the website to learn more about the new meter. If the meter replacement could not be completed, the door hanger will indicate that a return visit is required and provide a number for the customer to call to schedule an appointment.

Additional Contact Attempts – If a customer's meter is indoors or in another location that the installer cannot access (e.g., behind a locked gate) and the customer is not home to provide access to the meter, Rhode Island Energy's deployment vendor will follow a nine-step contact attempt process consisting of a combination of three phone calls, three field visits and three notification letters to attempt to contact the customer and schedule an appointment to complete the meter replacement. If the customer does not provide access after the nine contact attempts have been made, the meter replacement order will be returned to the Rhode Island Energy deployment team to review and determine the next appropriate action. If a customer refuses to allow the meter replacement, they will move to the customer concerns process, outlined in Section 9.3.

9.2.3 Phase 3: Advanced Features and Services

Rhode Island Energy's AMF solution provides many advanced features for customers such as having the ability to view and analyze hourly usage data. During the last phases of the program the scope will include integration of the AMF meter with a customer's HAN device. These devices are purchased by the customer and can be provisioned to communicate directly to the new AMF meter providing the customer with near real time visibility into their usage. Rhode Island Energy will develop this program, including easy to follow instructions for the customer to determine what devices are authorized to communicate with the meter and how to get them provisioned. This phase will continue throughout the lifetime of the new meters, evolving as new programs and energy saving technologies are introduced. The Company will continue to evaluate new Behind-the-Meter applications and tools as the technology emerges and determine the best ones to offer to customers. The new AMF meters will enable these new applications which will provide even more benefits to customers.

The Phase 3 communications activities will be further developed once the scope of new programs and HAN technologies becomes more clearly defined. PPL currently plans to offer some combination of the following communications initiatives:

- Direct Mail Notification to Customers
- Email Notification to Customers
- Demonstration Videos
- HAN Brochure and FAQs
- Website Update

9.3 Customer Concerns Related to AMF Meters

The implementation of the new AMF system will enable new features and benefits for both Rhode Island Energy and its customers. The AMF system is also expected to generate inquiries from customers regarding the new technology. The Company has conducted research across government organizations, scientific studies, industry groups, consumer education non-profits, and court rulings, all of which have concluded that the low-level frequency produced by smart meters poses no credible health or safety threats to consumers. These findings are summarized in Section 10.

Rhode Island Energy is committed to addressing customer inquiries and alleviating any confusion regarding the impact of the new technology. Materials developed for customers including FAQs and brochures will be designed to educate customers about the technology and will contain targeted information to address common customer inquiries and concerns. These materials will be evaluated and updated as necessary throughout the program based on the volume and types of concerns received. Examples of communications that PPL has used in the past and will likely be adopted for Rhode Island can be found in Attachment F.

Rhode Island Energy's AMF installation vendor call center ("Call Center") agents, as described in the detailed deployment plan provided in Attachment D, will be trained to have the tools and knowledge required to address customer inquiries regarding the new AMF system and meters. Contact Center representatives will also be provided with FAQs, brochures and talking points. The majority of customer concerns will be handled by the Rhode Island Energy Call Center where customers' concerns can be addressed by Call Center agents. If a customer has a complex question and desires more information than can be provided by the agent, Rhode Island Energy will establish a process to place the customer in contact with a member of the program team or other subject matter expert who will work with the customer to better understand and address their concerns.

9.4 Long-term Strategy for Leveraging AMF Platform

The longer-term objective of the CEP strategy is to inform and educate Rhode Island Energy customers on the benefits of AMF meters to increase customer access to new technologies and to empower customers to utilize new insights and services. Many of the customer benefits lie within the increased granularity and timeliness of the energy usage data that the AMF platform will deliver. Access to this information helps tie energy usage directly to the cost of energy, providing customers with the opportunity to change their energy usage, particularly when combined with time-varying rates. Customers can benefit from:

- Improved access to timely energy usage data
- Enhanced control over energy management and costs
- Increased choices on ways to save money throughout their billing cycle
- Expanded communication on outages and restoration; and
- Greater innovative energy solutions knowledge and insights

The Company will continue to build out and refine its Customer Portal, which will be the customers' new touchpoint to access their energy data, helping customers to interpret their energy consumption and manage their energy usage to effectuate bill savings. Customers will be able to share their energy usage data with third-party energy service providers through Green Button Connect ("GBC") to access various service offerings. As GBC continues to evolve in the industry, Rhode Island Energy will continue to explore how the GBC function within the Customer Portal can be expanded and improved. AMF will also allow for new direct, automated linkages of energy usage data and price signals to a customer's home-area network ("HAN") Customers who connect to a HAN can also leverage third-party vendor technology, as well as internet-based options to monitor and control their energy usage. Taken together, the future state following the proposed AMF and GMP deployments will be mutually beneficial for both end-use customers and Rhode Island Energy alike.

9.5 Leveraging PPL's Customer Segmentation Data

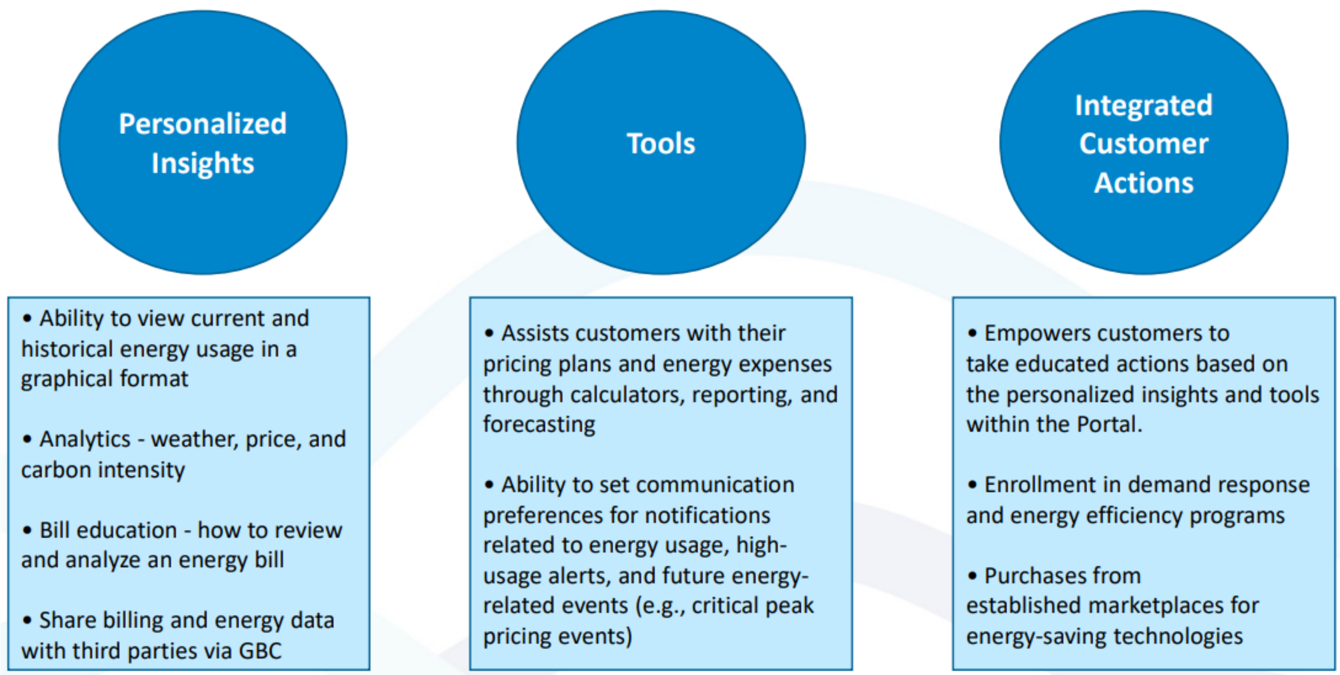
Rhode Island Energy will leverage PPL's work on customer segmentation data. PPL established customer segments that have been in place for several years and are an integral part of the PPL marketing and communications efforts. This data has contributed to PPL's exceptional results in the area of residential and business customer satisfaction and the multiple JD Power awards that PPL has received. The strategy uses several levels of data to determine the customer segments. Primary data includes operational data such as survey results, transaction, interaction and account history, program and service enrollments, usage, and billing/payment behavior. Secondary data, such as household, life-stage, socio-economic, demographic and business characteristic data is used to supplement primary data. The same customer segmentation strategy will be implemented for Rhode Island Energy customers and used by the AMF program so Rhode Island Energy can target communications to customers, specifically when it comes to the rollout of future functionality, programs and services being offered.

9.6 Customer Portal ("CP")

Each residential customer has different needs when it comes to using, understanding, and paying for their energy. Recognizing this, the Company will design the Customer Portal to not only provide better insights and tools in one place, but to allow for alerts, predictive analytics, and a window into the use of granular smart meter data. The Customer Portal is an integrated hub of energy data, insights, and actions available for all customers.

The Customer Portal is comprised of three main components: personalized insights, tools, and integrated customer actions. The first component, *personalized insights*, will bring together customer energy usage, better understanding of customer bills, and energy savings recommendations. The second Customer Portal component, *tools*, helps assist the customer with their pricing plans and energy expenses through calculators, reporting, and forecasting. Customers will be able to set (digital and non-digital) communication preferences with the Company for notifications related to energy usage, high-usage alerts, and proactive notifications of future energy-related events (e.g., critical peak pricing events). The third Customer Portal component, *integrated customer actions*, will empower customers to take educated actions based on the personalized insights and tools mentioned above. Actions such as enrollment in the Company's demand response and energy efficiency programs, purchases from established marketplaces for energy-saving technologies, and other actions can all occur in one convenient location on the Customer Portal. The primary features of these three components can be seen below in figure 9.3.

Figure 9.3: Customer Portal Features



Additional value can be delivered by connecting customers to their energy usage data. For example, high-usage alerts can be proactively provided to help customers to better manage their energy consumption. It will allow customers to access accurate and personalized energy usage information, as well as enable various choices and options to enroll in programs and services that can leverage the more granular data provided by AMF meters.

The Customer Portal will facilitate PPL's integrated Customer Experience ("CX") omni channel portal that includes functionality enabled by the new meters and all of the new data that becomes available with AMF. Coinciding with the expiration of the TSA, customers will begin using PPL's website, thereby providing customers with simple, seamless access to tools, information, and actionable insights that can be accessed through a streamlined website or by mobile device.

Once activated, the Customer Portal will not only allow customers to access accurate and personalized energy usage information, but also various choices and options to enroll in Company and third-party programs and services that can leverage the more granular data provided by AMF meters. Some Customer Portal components, like monthly energy summaries with average usage in smaller increments, could also be layered into non-digital communications like the customer bill or bill inserts. PPL also plans to expand and update the Customer Portal over time as necessary to meet the evolving needs of customers. New features and existing programs, such as integration with DERs, energy storage, and electric vehicles, can be integrated into the Customer Portal as these technologies become more widely utilized by customers. The Company envisions the Customer Portal to be the one-stop place to manage all customer energy needs today and into the future.

9.7 Breakdown of Data Components Available Under the Customer Portal

The Customer Portal ("CP") aims to provide more granular data to customers. Below are examples of data elements that may be transmitted and provided to customers and figures corresponding to how some of these elements will be displayed in the portal:

- Read Date & Days
- Read Type
- Total Kilowatt Hours (kWh)
- Net Metered Kilowatt Hours (kWh)
- Delivery Charges
- Supply Charges
- Late Payment Charges
- Total Charges
- Metered Peak Kilowatts (kW)
- Metered On-Peak kW
- Billed Peak kW
- Billed On-Peak kW
- Time of Use ("TOU") On-Peak kWh (applicable to specific rate design)
- TOU Off-Peak kWh (as applicable to specific rate design)

- Reactive Power
- Load Factor

Figure 9.4: Monthly Billing Estimate

Figure 9.5: Monthly Energy Use

Figure 9.6: 15-Minute Interval Customer Usage Data Export

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X
Meter Number	Date	Min	Max	Total	12:00 AM	12:15 AM	12:30 AM	12:45 AM	1:00 AM	1:15 AM	1:30 AM	1:45 AM	2:00 AM	2:15 AM	2:30 AM	2:45 AM	3:00 AM	3:15 AM	3:30 AM	3:45 AM	4:00 AM	4:15 AM
301334557	07/26/2022	0.08	0.84	17.09	0.16	0.16	0.2	0.17	0.17	0.14	0.16	0.16	0.16	0.14	0.14	0.16	0.16	0.13	0.12	0.16	0.45	0.1
301334557	07/25/2022	0.1	1.12	20.18	0.2	0.2	0.16	0.17	0.17	0.19	0.18	0.2	0.19	0.15	0.17	0.14	0.18	0.17	0.19	0.17	0.15	0.17
301334557	07/24/2022	0.11	1.42	30.66	0.19	0.18	0.21	0.18	0.19	0.17	0.16	0.19	0.19	0.18	0.15	0.2	0.2	0.21	0.18	0.18	0.18	0.2
301334557	07/23/2022	0.06	1.12	15.94	0.19	0.46	0.17	0.15	0.2	0.19	0.19	0.2	0.18	0.16	0.18	0.2	0.17	0.17	0.15	0.17	0.17	0.16
301334557	07/22/2022	0.06	1.69	27.08	0.21	0.18	0.16	0.2	0.18	0.19	0.2	0.16	0.17	0.19	0.18	0.15	0.14	0.16	0.16	0.2	0.12	0.11
301334557	07/21/2022	0.05	0.68	17.06	0.21	0.21	0.19	0.19	0.2	0.21	0.17	0.18	0.16	0.21	0.18	0.19	0.17	0.18	0.18	0.16	0.17	0.2
301334557	07/20/2022	0.1	1.32	20.65	0.16	0.18	0.14	0.17	0.16	0.13	0.15	0.15	0.16	0.14	0.13	0.14	0.15	0.15	0.11	0.15	0.16	0.13
301334557	07/19/2022	0.07	0.67	17.5	0.16	0.14	0.12	0.12	0.12	0.12	0.14	0.16	0.14	0.12	0.12	0.11	0.14	0.15	0.47	0.13	0.13	0.1
301334557	07/18/2022	0.06	1.43	20.05	0.14	0.13	0.14	0.15	0.14	0.13	0.12	0.2	0.44	0.1	0.15	0.15	0.13	0.12	0.13	0.14	0.12	0.13
301334557	07/17/2022	0.06	1.3	20.11	0.17	0.14	0.12	0.16	0.14	0.13	0.15	0.14	0.14	0.12	0.11	0.15	0.12	0.11	0.13	0.16	0.13	0.16
301334557	07/16/2022	0.06	0.76	16.58	0.11	0.13	0.15	0.45	0.11	0.14	0.13	0.15	0.11	0.1	0.15	0.15	0.09	0.11	0.15	0.12	0.08	0.15
301334557	07/15/2022	0.06	1.2	16.47	0.16	0.19	0.51	0.13	0.15	0.15	0.16	0.15	0.13	0.15	0.16	0.13	0.12	0.16	0.15	0.11	0.16	0.14
301334557	07/14/2022	0.08	1.86	20.78	0.13	0.14	0.17	0.17	0.11	0.13	0.16	0.13	0.12	0.13	0.14	0.13	0.12	0.14	0.14	0.14	0.09	0.13
301334557	07/13/2022	0.08	0.87	17.71	0.17	0.15	0.18	0.15	0.13	0.14	0.14	0.16	0.12	0.12	0.14	0.16	0.44	0.12	0.16	0.11	0.12	0.14

C&I customers will have access to new features, such as a portfolio-level view allowing them to seamlessly access information across multiple accounts. Rhode Island Energy will leverage customer segmentation data to enable meaningful insights for an individual customer. In a future state with TVR, this information will provide suggested actions that could help reduce consumption and/or shift load to less expensive periods.

9.8 Supplier Portal

Suppliers and NPPs also will realize benefits from AMF through the PPL Supplier Portal ("SP"). The PPL SP has been available to Suppliers in Pennsylvania since 2013 and it has gone through several phases of added functionality and improvements since then. Rhode Island Energy suppliers will have access to the PPL SP free of charge at the end of the TSA period. Then, as existing meters are replaced with AMF meters, Suppliers will begin to access even more granular 15-minute usage data for their customers. The Supplier Portal was designed to provide Suppliers with the ability to have timely access to customer information to enhance their ability to provide services to the market. The Portal is not meant to replace the Electronic Data Interchange process but rather to supplement it. User roles in the SP are tightly controlled to ensure Suppliers are able to access only information for their customers. Audit reports are also regularly run to verify that the data requests are appropriate. Functionality in the SP includes:

- Request customer bill image
- Request monthly usage – summary
- Request ICAP & NITS

- Load Profile
- Meter Constant
- Request customer historical interval usage
- Supplier contact information
- Download Eligible Customer List

9.9 Utilizing AMF to Satisfy Net Metering Requirements and Renewable Energy Growth Program ("REGP")

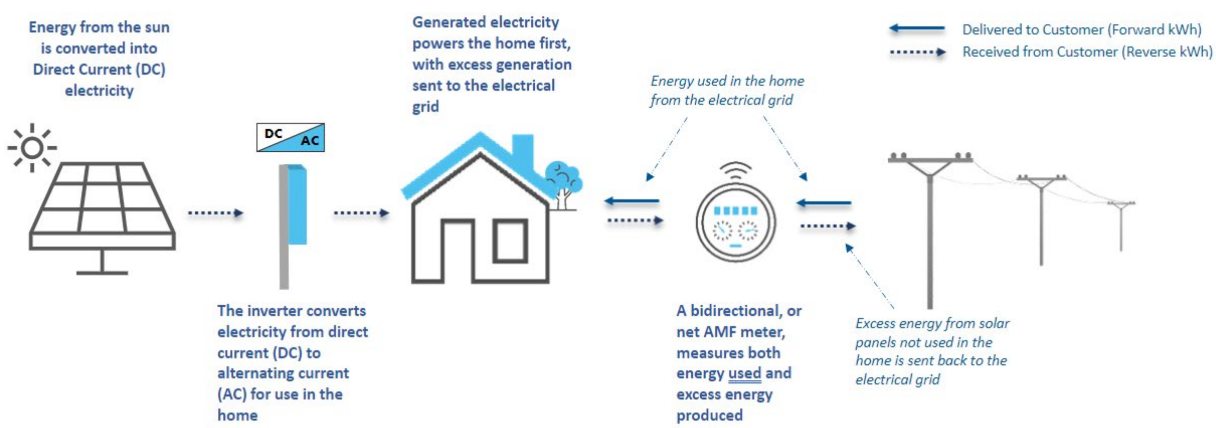
In Rhode Island, net metering is administered under the Company's electric tariff. AMF meters will be well-suited to serve net metered customers. The use of AMF would not affect the methodology for calculating and applying net metering credits.

The use of an AMF meter for net metering or Renewable Energy Growth Program ("REGP") will allow for accurate reporting of either net generation (under net-metering) or total generation (under REGP) to the ISO-NE so that wholesale revenues can accrue to the Company and would be used to offset the costs of either program.

As the AMF meters proposed in this Business Case have interval metering, any expansion or changes to the net metering or REGP could occur without requiring the meter to be replaced. Over-the-air software and firmware updates will allow for remote re-programming if needed. In addition, the use of raw interval data can be manipulated by the MDMS proposed to allow for numerous billing scenarios, including time-varying credit payments, which would better reflect the value of DG to the system and would mimic the TVR pricing expected for consumption. In addition, virtual bills for multiple off-takers from a solar or wind farm (community renewable energy applications) can be constructed if the need arises with the use of the raw data from an AMF meter.

AMF technology provides several benefits for net metering by capturing the forward and reverse energy flows measured by AMF meters. 15-minute energy data values are sent to the utility's MDMS where kWh Net consumption is calculated by subtracting kWh Received (from the customer) from kWh Delivered (to the customer) and made available to customers through an online Customer Portal. Raw data includes both received and delivered kWh and will be available for viewing 30 to 45 minutes after meter registration. Billing quality data includes received, delivered, and calculated Net kWh values and will be available within 24 hours after raw data has been through the VEE process. The enhanced usage perspective from AMF meters not only allows customers to better understand how they are consuming generated energy from their on-site DERs, but also helps Rhode Island Energy Customer Representatives and other utility staff better answer questions related to net-metered services and associated energy bills. Presently, energy bills include Net kWh and a banked energy total representing excess energy that has been transferred back to the grid. See Figure 9.7. After an AMF meter is installed, bills will also include Delivered and Received kWh energy values, resulting in fewer questions about how bills are calculated for net-metered services.

Figure 9.7: How Residential Net Metering Works



As part of Rhode Island Energy's REGP, customers can sell generated output back to the utility under long-term tariffs at fixed prices. REGP customers currently have two meters installed. This includes a net meter at the residence, and an additional meter at the inverter to measure Generated kWh. Both meters will be replaced with an AMF meter so the customer and the utility can access the detailed, 15-minute energy values from both locations. By aligning like intervals, REGP customers will be able to determine when they receive the most benefit from local generation by comparing Generated kWh to Delivered, Received, and Net kWh. In the future, Rhode Island Energy anticipates the availability of a single AMF meter with multiple ports that would alleviate the need for installing two meters. At that time, the Company may choose to change the metering requirement for new and/or existing REGP customers to replace the existing meter base with one that accommodates the additional ports.

Figure 9.8: Example of how AMF meters measure generated energy and energy used throughout a 24-hour period.

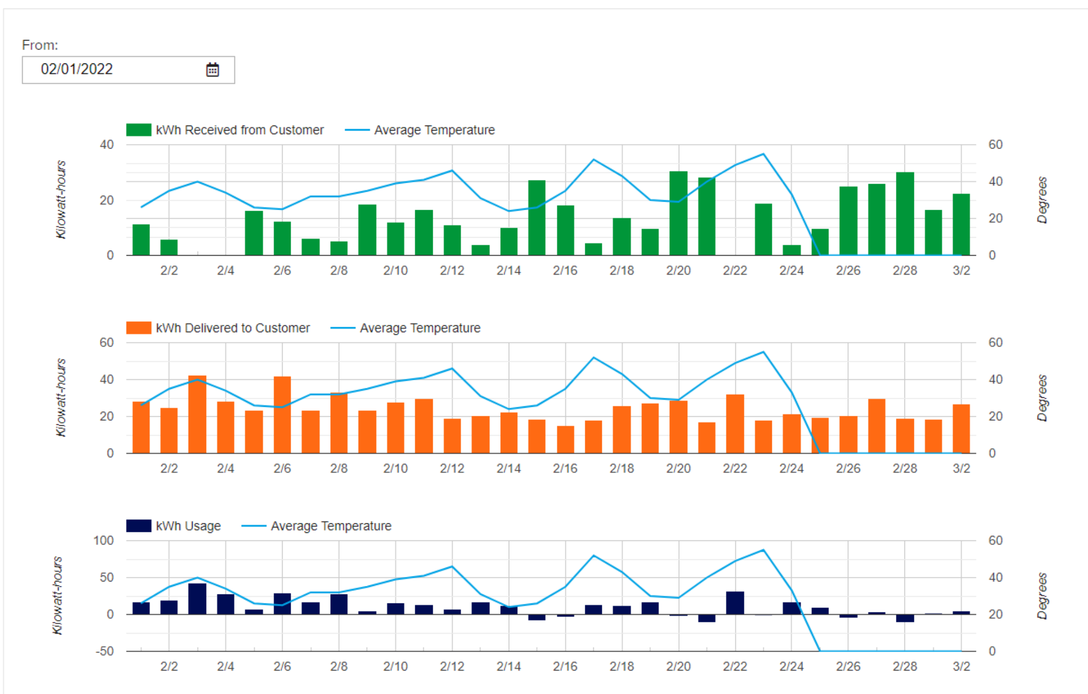
Time Range	AMF meter at Inverter Generated Energy (kWh)	Energy (kWh) Used	AMF Net Meter Registration		
			Channel 1	Channel 2	Derived in MDMS
			Forward Usage (kWh Delivered)	Reverse Usage (kWh Received)	Net Usage (kWh Delivered – kWh Received)
12AM-1AM	0	1	1	0	1
1AM-2AM	0	1	1	0	1
2AM-3AM	0	1	1	0	1
3AM-4AM	0	1	1	0	1
4AM-5AM	0	1	1	0	1
5AM-6AM	0	3	3	0	3
6AM-7AM	1	4	3	0	3
7AM-8AM	1	3	2	0	2
8AM-9AM	2	2	0	0	0
9AM-10AM	3	2	0	1	-1
10AM-11AM	10	1	0	9	-9
11AM-12PM	10	1	0	9	-9
12PM-1PM	5	2	0	3	-3
1PM-2PM	5	1	0	4	-4
2PM-3PM	3	2	0	1	-1
3PM-4PM	2	3	1	0	1
4PM-5PM	1	5	4	0	4
5PM-6PM	0	4	4	0	4
6PM-7PM	0	3	3	0	3
7PM-8PM	0	3	3	0	3
8PM-9PM	0	2	2	0	2
9PM-10PM	0	1	1	0	1
10PM-11PM	0	1	1	0	1
11PM-12AM	0	1	1	0	1
	43 kWh	**49 kWh**	**33 kWh**	**27 kWh**	Billed Usage **6 kWh**

The table above shows an example of how AMF meters measure generated energy and energy used throughout a 24-hour period. 60-minute intervals are listed for simplification. Rhode Island Energy AMF meters will display usage value for every 15-minute interval.

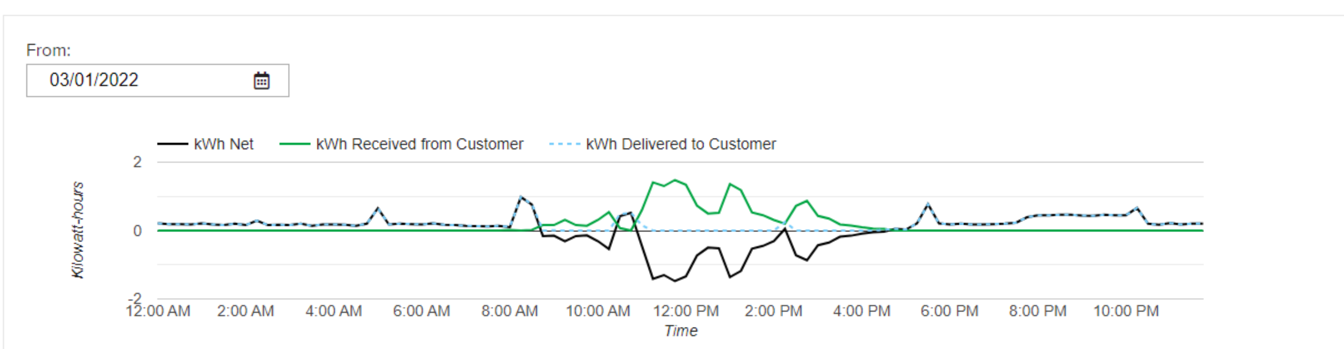
Included in Figure 9.9 below are example usage charts generated from the MDMS. Customers and contact center agents will have visibility into Received, Delivered, and Net Usage channels from net meters in the customer portal within 24 hours.

Figure 9.9: Example usage charts generated from the meter data management system available in 24 hours

Daily Electricity Usage



Hourly Electricity Usage



9.10 Leveraging AMF for Improving Energy Efficiency Programs

The programs offered through the Company's annual energy efficiency plan cover a wide variety of customer segments reaching hundreds of thousands of customers. The residential programs include no-cost home energy assessments where many energy upgrades are also at no-cost or have generous incentives available to assist customers in moving forward with upgrades. There are programs dedicated to lighting products, HVAC opportunities, and behavioral energy savings. Installation of AMF technology will allow for more granular energy consumption data to enable real-time energy optimization which will be useful to enhance or create new energy efficiency programs. The more granular data would result in an improvement to the current non-AMF high-bill alerts.

9.11 Customer Choice and AMF Opt-Out

Rhode Island Energy's goal is for full adoption of AMF by all customers to allow all customers to have access to the benefits provided by AMF meters. Rhode Island Energy will focus its Opt-Out campaign on decreasing the number of customers who decline to allow the Company to install an AMF meter by proactively alleviating typical concerns through awareness and education. Rhode Island Energy is committed to educating customers on the safety and security of AMF so they can make an informed decision. In the event customers choose to Opt-Out, a clear process will be provided to them explaining their options. Customers will be given advanced notice, via mail and email, of plans to install AMF meters and the opportunity to Opt-Out of the AMF metering program. Opt-Out information will be included in the letter/notification customers receive. Processes and resources to Opt-Out will be available to support customers who are considering or decide to pursue an alternative approach. All customers, including those who Opt-Out, will retain the right to purchase energy from third-party suppliers. For landlord/renter situations, the Company will provide the planned communications with the account holder, who is typically the renter. The account holder is expected to make the Opt-Out decision.

Early in the AMF deployment process, customers will be able to choose to Opt-Out of an AMF meter through customer service support. If a customer calls the Call Center, the customer service representative will ask to understand the reason the customer is interested in the Opt-Out provision, provide additional information as appropriate, and complete the Opt-Out process. At this time, the Company will aim to inform customers of AMF program benefits, privacy information, and impacts of selecting the Opt-Out provisions, including the consequential rate impacts.

Customers will continue to be able to Opt-Out at any time leading up to the day of the AMF meter installation. On the day of installation, if the customer chooses to Opt-Out when the utility representative makes initial contact, the technician will not install the new AMF meter at that location. The utility representative would contact a supervisor to place a "hold" on the installation and the Company would then provide the customer with instructions on how to contact Rhode Island Energy to verify that they do not want an AMF meter. If the customer then chooses to Opt-Out by submitting the form, the Company will follow-up with a confirmation to the customer that clearly explains the implications to the customer experience and the customer responsibilities moving forward.

The Company will seek to learn as much as possible from Opt-Out customers, including why they are choosing to Opt-Out and foregoing the opportunity to participate in future benefits. This will allow the Company to focus additional resources toward other sectors, or specific customer groups that may be at risk of opting out. Customers choosing to Opt-Out of an AMF meter will receive additional education on the benefits they would likely forego by not participating, based on their access to features and services requiring smart meter data (e.g., more personalized usage insights and bill-saving opportunities with new potential TVR plans). If a customer prefers not to receive the additional materials, they may inform the Company, and the Company will honor the customer's request.

Customers who Opt-Out of an AMF meter will be subject to charges consistent with the terms and conditions specified in the Company's current Opt-Out meter reading tariff. These charges will be communicated within each phase of the plan. Opt-Out charges can be examined prior to AMF meter installation using an approach similar to that prepared in Docket No. 4342, where the PUC approved the AMR opt-out fees. Charges are likely to include a one-time meter exchange fee and a monthly manual meter reading fee.

For those customers who Opt-Out, the Company will continue to provide information on AMF program benefits, health, safety, privacy, and security, as well as the path to Opt-in through the website and customer service support. Customers who choose to receive an AMF meter after initially choosing to Opt-Out, will receive an AMF meter at no additional cost.

9.12 Projected CEP and Customer Portal Implementation Costs

The Company estimates the total spend on customer engagement for AMF to be $12.6M in nominal terms which includes Customer Portal initial functionality that allows customers to view their energy usage as well as future functionalities around additional alerts, and GBC. For additional details, please see the Section 11 – Benefit/Cost Analysis.

Section 10

SECTION 10: ADDITIONAL CONSUMER PROTECTIONS

This section describes how Rhode Island Energy is committed to providing customer protections ensuring that health concerns are fully addressed, highlighting scientific studies, expert testimonies, and technical literature verifying that the radio frequency technology used by the AMF solution does not present a health risk for customers. Also, this section demonstrates Rhode Island Energy's commitment to stewarding AMF data through its Cybersecurity, Privacy and Data Governance Plan as a consumer protection making data accessible and keeping it secure, while also guarding customers' privacy.

Rhode Island Energy is committed to providing essential customers protections throughout the life cycle of AMF. In addition to providing a proposal that is cost effective and investing in infrastructure that will more fully engage customers and offer additional affordability options, this Section addresses two additional customer protections. Health considerations for AMF area addressed by providing references to scientific studies and a wide range of literature that cite evidence for consumer safety. This Section in conjunction with Attachment G also provides cyber and privacy protection by having data governance in place that defines conditions for access system, customer and billing data with a defined process to keep it relevant as technology evolves. The approach planned for related customer education and messaging is also included in this Section.

10.1 Research for AMF Health Considerations

Advanced meter solutions in other states have previously generated concerns around RF exposure.[41] The Company has conducted research across government organizations, scientific studies, industry groups, consumer education non-profits, and court rulings, all of which have concluded that the low-level frequency produced by smart meters poses no credible health or safety threats to consumers. These findings are summarized below, and further detail can be found in the links presented at the end of this Section. Rhode Island Energy will also make these health aspects known to customers related messaging into the Customer Engagement plan.

An illustrative representation of health awareness communications that is planned is included in Attachment F. Key messages consist of the following:

[41] *See e.g., Investigation by the Dep't of Pub. Util. on its own Motion into Modernization of the Elec. Grid,* Docket D.P.U. 12-76-B at 37, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208 (June 12, 2014) ("After careful review of all the information, scientific research, and data presented in this proceeding, and consideration of other jurisdictions' studies, reports and approaches, we conclude that the best balance of these factors is to allow electric distribution companies to include their plans to achieve advanced metering functionality the broad deployment of advanced meters, but to require the companies to provide customers with an option to decline the installation of advanced meters.").

- When the meter is not signaling, there is no RF field surrounding or near the meter.
- There is no reliable scientific basis for a mechanism by which RF fields can cause effects in the human body other than through heating, i.e., a thermal effect. The RF fields from the AMF meter being used by Rhode Island Energy are far too low to cause a heating/thermal effect.
- The RF field levels from the AMF meters being used by Rhode Island Energy more than comply with the applicable FCC RF exposure limit for the radio in the AMF meters. The FCC exposure limit is based on a 30-minute average exposure, and the 30-minute average RF field level from the AMF meters being used by Rhode Island Energy is 98,000 times smaller than the FCC exposure limit.
- There is nothing unusual about the RF fields from the AMF meters. The RF fields from the AMF meters are the same types of RF fields that are used for radio communications by many common everyday devices, such as radios, garage door openers, baby monitors, portable phones, Wi-Fi, and other wireless communications devices.
- The RF fields 30 feet away from a person using a cell phone are 3 times larger than the RF fields from the AMF meters. The RF fields from using cell phones near the head can be over 260,000 times higher than the RF fields from the AMF meters.
- As an example, if a person were to use their cell phone to make 275 minutes of calls over a 6-month period (about 1.5 minutes of calls per day) they would need to stay within 1 meter of an AMF meter for 103,569 years to receive an equivalent level of RF exposure as they would from the cell phone. If this same person used a headset or earphones, they would still need to be within 1 meter of an AMF meter for 259 years to receive an equivalent amount of RF exposure. This does not consider other usage of the cell phone such as texting and internet browsing which would only increase the amount of RF exposure from typical cell phone usage.
- The RF exposures from microwave ovens can be more than 820,000 times larger than the RF fields from the AMF meters.
- Background RF fields from television broadcast towers is often many times higher than the RF fields produced by AMF meters.

Every day, people are exposed to low levels of RF energy, from natural sources, such as the sun, the Earth and the Earth's outer atmosphere, and from man-made sources, such as telecommunications and common electronic devices like cell phones or microwaves. The Federal Communications Commission ("FCC") requires testing of all wireless communications devices to ensure they meet minimum guidelines for safe human exposure to RF energy before allowing the devices to be used.[42] The smart meter technology the Company proposes to use is no different. All smart meters installed will follow the FCC process, certifying the meters are safe and comply with applicable government safety standards.

The existing scientific research supports the assertion that smart meters are safe for consumers. In 2010, the California Council on Science and Technology ("CCST") received a request from the California Assembly to perform an "independent, science-based study" to help policymakers and the public resolve the debate on smart meter health risks. The CCST's final report in 2011 concluded: 1) "the FCC standard provides an adequate factor of known RF induced health impacts of smart meters"; and 2) "there is no evidence that additional standards are needed to protect the public from smart meters."[43] The report further details that even in a worst-case scenario in which a meter is constantly relaying data at a 100% duty cycle, RF emissions "would be measurably below the FCC limits for thermal effects."[44]

Importantly, RF energy is only emitted when smart meters are transmitting data. Research from the Electric Power Research Institute ("EPRI") on 47,000 smart meters installed in Southern California found that 99.5% of meters were transmitting for three minutes or less a day. EPRI concluded that smart meters are below FCC limits.[45] A 2010 study from the Utilities Telecom Council provides a useful comparative perspective, highlighting that smart meters present significantly less exposure than many common devices, such as laptop computers (100-200 x greater), cell phones (300-100,000 x greater), and microwave ovens (50,000 x greater).[46]

The Smart Energy Consumer Collaborative ("SECC"), an energy consumer education nonprofit, offers an additional view, concluding that "smart meters do not produce any negative health

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[42] Federal Communications Commission, *RF Safety FAQ*, https://www.fcc.gov/engineering-technology/electromagnetic-compatibility-division/radio-frequency-safety/faq/rf-safety#Q10.

[43] California Council on Science and Technology, *Health Impacts of Radio Frequency Exposure from Smart Meters*, https://www.ccst.us/wp-content/uploads/2011smart-final.pdf (April 2011).

[44] *Id.* at 15.

[45] *See* Electric Power Research Institute, *Characterization of Radiofrequency Emissions From Two Models of Wireless Smart Maters* v. (December 2011), https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/advanced_meters/04_EPRI_Characterization%20of%20Radio%20Frequency%20Emissions %20From%20Two%20Models%20of%20Wireless%20Smart%20Meters.pdf.

[46] *See* Utilities Telecom Council, *No Health Threat from Smart Meters 6,* https://www.nema.org/docs/default-source/technical-document-library/smartmeter-nohealththreat.pdf *(2010) (Comparison: cell phone RF frequency when held up to head; microwave RF frequency when turned on and close to door; smart Meter frequency when standing 10 feet away from meter.).*

impacts."[47] According to the SECC, even standing continuously in front of a smart meter would result in RF exposure approximately 70 times less than FCC limits.[48]

In 2015, The Maine Coalition to Stop Smart Meters challenged the Maine Public Utilities Commission's finding that smart meters do not pose a health risk. The case went to the Maine Supreme Judicial Court in 2016, which confirmed the Maine Public Utilities Commission's finding, ruling that smart meters installed by Central Maine Power Co. pose "no credible threat to the health and safety" of the utility's 615,000 customers who have them installed.[49] The court cited the Maine Center for Disease Control and Prevention's findings in 2010, which concluded there was no indication of "any consistent or convincing evidence to support a concern for health effects related to the use of RF in the range of frequencies and power used by smart meters."[50]

The Company is making it a priority to educate and communicate with consumers and other stakeholders early and often to improve public confidence and acceptance of AMF technology. As detailed in the CEP, information on smart meter safety and customer support will be available to customers before, during, and after meter deployment. In addition, Rhode Island Energy plans to have mechanisms in place to address customer concerns during each phase of deployment. All customers will also have the choice to opt out of the AMF metering program. However, the Company notes that it cannot remove other customers' meters because they are in proximity to the home of a customer who opts out of having an AMF meter. The following are additional sources that address AMF health concerns:

- Evaluating Compliance with FCC Guidelines for Human Exposure to Radiofrequency Electromagnetic Fields. Federal Communications Commission Office of Engineering & Technology Bulletin 65 (August 1997).

- Smart Meter – What We Know: Measurement Challenges and Complexities – A Technical Paper to Clarify RF Radiation Emissions and Measurement Methodologies. Environmental Testing & Technology, Inc. (December 2011).

- Electromagnetic fields and public health: Base stations and wireless technologies. World Health Organization (May 2006).

47 *See* Smart Energy Consumer Collaborative, *Radio Frequency and Smart Meters,* https://smartenergycc.org/download/seccs-radio-frequency-and-smart-meters-fact-sheet/ *(2011).*

48 *See Id.* at 2.

49 *See Friedman v. Pub. Utilities Comm'n*, 132 A.3d 183, 187 (Me. 2016).

50 *Id.*

- Guidelines for Evaluating the Environmental Effects of Radiofrequency Radiation. Federal Communications Commission (August 1996).

- Characterization of Radiofrequency Emissions from Two Models of Wireless Smart Maters. Electric Power Research Institute (2011).

10.2 Cyber and Privacy Protections Using Data Governance

AMF brings with it many new data collection, communication, and information sharing capabilities related to energy usage, and these technologies in turn introduce concerns about both security and privacy. Security and privacy are important to *individuals*, directly relating to customers' personal information, personal privacy, behavioral privacy, and personal communications privacy. Recognizing the need to maintain and enhance a defense in depth cybersecurity plan to prevent and mitigate everchanging cyber threats, and address privacy aspects, the Company has developed pertinent policies addressing data privacy, data governance, information classification, and cyber security, and enterprise security standards. Through these policies and standards, the Company seeks to provide standard information security practices to safeguard the privacy of personal information effectively and consistently while also supporting its critical infrastructure and vital business functions, including AMF. The Company's commitment to stewarding AMF data is memorialized through its Cybersecurity, Privacy and Data Governance Plan in Attachment G which provides provisions to making data accessible while keeping it secure and maintaining customers' privacy.

As discussed earlier in the Business Case, AMF provides capability for customers to authorize the sharing of their data to third parties. There are three ways in which customers' data can be shared using secure, controlled, and standards-based processes:

- **NPPs (Non-regulated Power Producers)** – Energy Suppliers can access customers' data that enroll in their services in two different ways: 1) Electronic Data Exchange; and 2) SP.

- **Green Button Connect** – Customers can access their own data through the Customer Portal and download usage for use in third party analyzers. The customer has ownership of where their data goes and whether it can be shared with a third party.

- **Supplier Portal** – The SP, modelled after the PA Supplier Portal, will be made available in Rhode Island where NPPs and other market participants (Marketers, Brokers, Curtailment providers) can access customer data at differing levels.

Section 5.5 provides a technical overview of the customer programs and describes how billing data is handled. It also describes the customer portal and options that customers have access to manage their data, such as Green Button Connect. The Company also recognizes that the timeliness and availability of the energy usage data are of growing importance to support services, innovative rate designs and incentives, enhanced customer education, and demand response capabilities. As such, Section 5.6 addresses key design considerations resulting in "data latency" referring to the time delay from when a meter or endpoint captures data to when the information is available to a customer or authorized third-party service provider in raw and in billing form. This AMF data latency establishes the timing of when energy service providers, customers and third parties can expect to have access to granular data to plan offerings accordingly.

The Data Governance Plan exists to ensure the data generated by the Company through AMF is collected, managed, stored, transferred, and protected in a way that preserves customer privacy, and is consistent with cybersecurity requirements, as well as grid modernization objectives and the Climate Mandates. It provides a framework of corporate policies that have been developed to ensure the management, protection, and secure availability of the Company's data and information assets is appropriate and maintained. It is based upon risk-based cybersecurity framework components that focus on principles, regular assessments and constant vigilance using an approach that tracks across people, process and technology. Furthermore, the Data Governance Plan defines organizational commitment to having enterprise-wide operational processes that provide robust security environment for the AMF project with specific responsibilities defined for AMF cybersecurity. The Data Governance Policy, one of several policies that support the Data Governance Plan, further defines the roles and responsibilities for different data creation and usage types, and maps clear lines of accountability. It also develops best practices for effective data management and protection, ensuring that a process is in place to comply with applicable laws, regulations, exchange, and standards and establishes a mechanism to ensure that a data trail for vulnerabilities, threats and complaints is effectively documented and managed.

To ensure emerging security and privacy risks are identified and adequately addressed, the Company is committed to using a process that identifies vulnerabilities by conducting an initial privacy impact assessment before deploying AMF. The approach for the impact assessment is defined by NISTIR 7628 Guidelines for Smart Grid Cyber Security. The assessment compares the NIST Guidelines to the Company's existing privacy policies, procedures and the AMF implementation plan to identify where best practices are in place or further alignment is needed given the emerging security and privacy challenges that are presented by AMF. Acting with the privacy impact assessment demonstrates that the Company understands that AMF technologies brings new types of information that can involve security and privacy and is evidence of the Company's commitment to the Data Governance Plan. If needed, the Company will provide communications relating to privacy and security risks and what can be done to mitigate them. Additionally, manufacturers and vendors of various aspects of the AMF system will be expected to engineer and operate to collect and limit the use of the data to only that necessary for purposes of AMF. Such elements may include but are not limited to customer assigned peak load conditions, energy and capacity loss factors, internal usage, and / or other information that may be needed for efficient wholesale and retail market participation. It will also address billing quality customer data such as electric usage in kWh containing register and interval reads with the proper privacy and security provisions.

Section 11

SECTION 11: BENEFIT/COST ANALYSIS

This section presents the AMF BCA approach and results including Docket 4600 alignment, cost contingencies, benefits by operations, customer and societal breakdown, and a cost-benefit sensitivity analysis.

11.1 Summary Results

The purpose of the Benefit/Cost Analysis ("BCA") is to demonstrate the benefits and costs of implementing AMF electric meters across the Rhode Island Energy service territory. Not only are the AMF meters critically needed for reliability and safety, but the overall results are significantly positive from a BCA perspective using the Docket 4600 Framework. Furthermore, the reliability and safety, customer, operational, clean energy, and financial benefits justify full deployment including: 1) AMF electric metering equipment; 2) a wireless radio frequency (RF) mesh communications network; 3) related information technology ("IT") management and network systems; and 4) implementation and programmatic services. Over a 20-year evaluation period, with a five-year deployment scenario, Rhode Island Energy expects to invest on a $2022 Net Present Value ("NPV") basis, $188.0 million. Over the 20-year life of the AMF meters, Rhode Island Energy expects Rhode Island customers and society to realize a total of $729.2 million in total benefits NPV-$2022. This results in a net value of benefits minus costs of $541.2 million NPV for the project and a BCA ratio of 3.9.

This section begins with a presentation of high-level results and includes detailed descriptions of the elements that compose the results. This section also includes comparisons between the BCA performed by the Company while still under National Grid ownership and the BCA performed by Rhode Island Energy.

Most AMF costs are incurred the first four years of project implementation. Costs incurred in the first two years of project implementation are associated with setting up back-office and IT systems to support the new meter functionality. Costs incurred in years three and four increase significantly as deployment and installation of the meters occurs. Corresponding with this electric meter deployment schedule, significant benefits from avoided AMR costs appear in years three and four as well. Following meter installation, O&M savings are anticipated in every year thereafter. Costs incurred following program implementation consist of only those costs necessary to maintain the system. The bulk of the benefits will phase in over time as the meters are replaced. Based on this stream of costs and benefits over time, the AMF program has a payback period of 8 years, both on a nominal and NPV ($2022) basis.

The cost and benefit results for a six-year AMF deployment scenario are shown in Figure 11.1 below.

Figure 11.1: Base Case
Benefits and Costs of Full AMF Deployment ($Nominal and $2022 NPV)

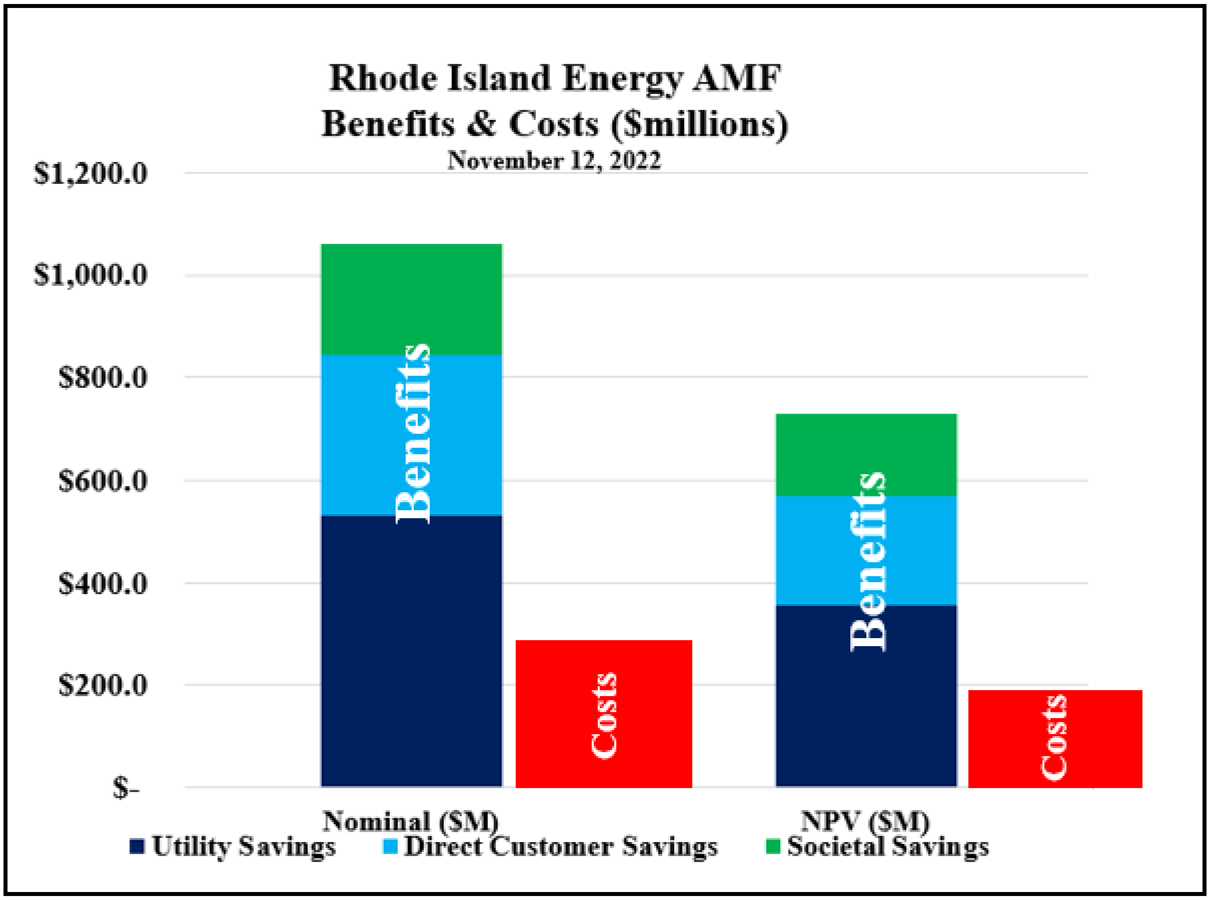
Financial Highlights and Summary ($NPV in Millions)		
As of November 12, 2022		
Business Case Component	Benefits (20-Year NPV)	
A. Costs		
O&M Expense for AMF System	$	57.5
New Capital Investment for AMF System	$	130.5
Total Costs		$188.0
B. Benefits		
Utility Benefits	$	354.7
Direct Customer Benefits	$	213.2
Societal Benefits	$	161.2
Total Benefits	$	729.2
C. Results		
Benefits Less Costs	$	541.2
Benefit/Cost Ratio	3.9	
Payback (Years)	8	

The benefits shown in Figure 11.1 result from:

- Avoided costs for replacing end-of-life AMR drive-by meters,
- Avoided costs for feeder sensors,
- Energy cost savings,
- Capacity cost savings,
- Transmission and distribution savings,
- Customer reliability savings,
- Savings from enabling TVR, and
- Societal/clean energy savings.

Rhode Island Energy calculated both the nominal and the Net Present Value ($2022) of the benefits and costs. Rhode Island Energy also grouped the benefits into Utility, Direct Customer and Societal benefits as shown above. Figure 11.2 depicts the benefits and costs from a nominal and an NPV perspective.

Figure 11.2: Graph of Benefits and Costs of Full AMF Deployment



The values shown above in Figures 11.1 and 11.2 are based on the Opt-In values for TVR that have been evaluated including Whole House Time-of-Use ("TOU") rates, Whole House Critical Peak Pricing ("CPP") rates, and peak demand and energy benefits associated with TVR for Electric Vehicles ("EV"). For each of these TVR benefits, Rhode Island Energy evaluated an "Opt-In" program and an "Opt-Out" program. The Opt-In and Opt-Out programs have very different estimated participation rates. The Opt-In program assumes 20% of eligible customers will participate while the Opt-Out program assumes 85% of the eligible customers will participate. It is further assumed that, while both groups ultimately reduce their peaks by the same amount, the Opt-In group achieves those savings more quickly than the Opt-Out group.

Assuming an Opt-In approach for TVR programs is more conservative than assuming an Opt-Out approach. Most Opt-In programs have significantly less participation than 20%. A Brattle report on TOU participation rates notes, "-Reasons for low enrollment … include no marketing of the TOU rate, inconvenient design (i.e., long peak period), and/or additional charges to cover cost of TOU meter (where smart metering has not been deployed)."[51] Utilities who are best-in-class and/or have Critical Peak Pricing have Opt-In rates of 20-50%.[52] Rhode Island Energy has not yet planned its Time Varying Rates approach and has the opportunity to learn from the best-in-class utilities. Figure 11.3 shows the benefits and costs of the Opt-In and Opt-Out scenarios for comparison to the Base Case.

Figure 11.3: TVR Programs: Opt-In and Opt-Out Results ($NPV in Millions)

TVR Opt-In (Base Case) & Opt-Out Comparison		
As of November 12, 2022	Opt-In Case	Opt-Out Case
A. Costs (20-Year NPV)	**$188.0**	**$188.0**
B. Benefits (20-Year NPV)		
Utility - Opt-In/Opt-Out	$161.3	$665.7
Utility - All Other	$193.5	$193.5
Direct Customer - Opt-In/Opt-Out	$0.0	$0.0
Direct Customer - All Other	$213.2	$213.2
Societal - Opt-In/Opt-Out	$2.3	$5.4
Societal - All Other	$158.9	$158.9
C. Total Benefits (20-Year NPV)	**$729.2**	**$1,236.7**
Benefits Less Costs	$541.2	$1,048.7
Benefit/Cost Ratio	3.9	6.6

As shown in Figure 11.3, if Rhode Island Energy were to develop its TOU/CPP/TVR programs with an Opt-Out approach, both the Utility Benefits and the Societal Benefits are significantly higher than they are with the Opt-In approach Rhode Island Energy has chosen for the AMF Business Case. Utility Benefits impacted by the Opt-In approach total $161.3 million NPV versus $665.7 million NPV with an Opt-Out approach. Similarly, Societal Benefits impacted by the Opt-In approach total $2.3 million NPV ($2022) versus $5.4 million NPV ($2022) with an Opt-Out approach. However, the total benefits of the AMF program are still significant with an

51 Ahmad Faruqui, Ryan Hledik, Sanem Sergici (of The Brattle Group), *A Survey of Residential Time-of-Use (TOU) Rates*, https://www.brattle.com/wp-content/uploads/2021/05/17904_a_survey_of_residential_time-of-use_tou_rates.pdf (November 19, 2019).

52 *Id.*

Opt-In approach, which results in an overall BCA ratio of 3.9. The BCA ratio increases to 6.6 if an Opt-Out approach is chosen.

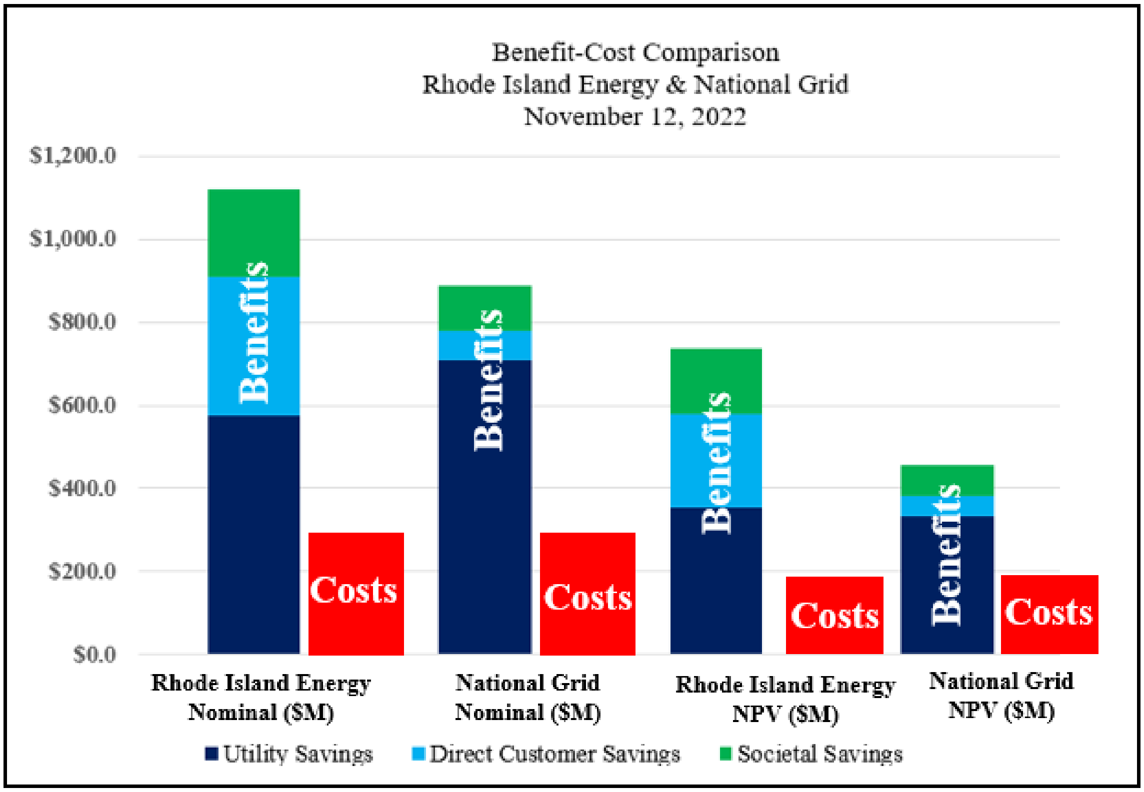
11.2 Comparison to Company's Previous BCA Under National Grid Ownership

Rhode Island Energy used much of the work that was done by the Company, while under National Grid ownership, in developing this BCA, including adopting the structure for the BCA and, in some cases, applying the previously calculated benefits. For both BCAs, the benefits significantly exceed the costs of a Full AMF deployment plan. Figures 11.4 and 11.5 depict the benefits and costs, both nominal and NPV, for this Business Case and National Grid's Updated AMF Business Case. As can be seen, the costs for both companies are nearly identical, while the benefits Rhode Island Energy calculated are higher.

Figure 11.4: Comparison of Rhode Island Energy and National Grid Benefits and Costs

Rhode Island Energy and National Grid Benefit/Cost Comparison		
As of November 12, 2022		
Nominal ($M)	**RIE**	**NG**
Utility Savings	$ 529.7	$ 708.5
Customer Savings	$ 314.5	$ 70.8
Societal Savings	$ 215.1	$ 109.7
Total Savings	$ 1,059.3	$ 889.0
AMF Costs	$ 289.0	$ 289.4
Benefit/ Cost Ratio	3.7	3.1
NPV ($2022 M)	**RIE**	**NG**
Utility Savings	$ 354.7	$ 333.3
Customer Savings	$ 213.2	$ 48.5
Societal Savings	$ 161.2	$ 75.0
Total Savings	$ 729.2	$ 456.8
AMF Costs	$ 188.0	$ 192.6
Benefit/ Cost Ratio	3.9	2.4

Figure 11.5: Graphical Comparison of Rhode Island Energy and National Grid Benefits and Costs



There are three major differences that can be observed looking at Figures 11.4 and 11.5. The first is that the Utility benefits are very similar from a Net Present Value ($2022) perspective, but the nominal benefits are significantly different. This result is driven by two main factors. First, National Grid's nominal Utility benefits are higher due to differences in the avoided energy and avoided capacity costs between the AESC 2018 Report and the AESC 2021 Report; energy values were 25-30% higher and capacity values were 40-45% higher in the 2018 report. Second, Rhode Island Energy discounted the Utility benefits that utilized the AESC values by 2% rather than 6.97% that National Grid used. The Company chose the 2% discount rate because the avoided cost values developed in the AESC 2021 report are shown in $2021dollars ("real" dollars) regardless of which year was being forecast. Rhode Island Energy inflated these values by 2% to develop the nominal values and discounted them by 2% to get back to the initial "real" values, adjusted to be $2022. This would create a much higher NPV than discounting those values at 6.97% but discounting values that are already "real" is not appropriate in calculating net present values. Hence, National Grid's Utility nominal benefits are higher because the energy and capacity costs were higher in 2018 and their NPVs are lower because they discounted them by 6.97% rather than 2%.

Second, the Customer benefits for Rhode Island Energy are significantly higher than those calculated in the National Grid Updated AMF Business Case. This is due to two significant benefits included by Rhode Island Energy that were not calculated or included in the National Grid Updated AMF Business Case. The first is the benefit associated with getting an immediate outage notification from the customer's meter rather than waiting for the customer to call in an outage. In Pennsylvania, PPL's experience with AMF meters is that outage notification with AMF meters occurs 22 minutes faster than notification by customers calling in outages. This allows PPL to dispatch crews 22 minutes faster. Although it does not change the time for the utility to fix the outage, it does reduce the customer's overall outage time by 22 minutes. This time saved results in dollar savings to customers which were estimated using the Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") calculator. The ICE calculator calculates savings to customers based on changes in either the utility's SAIFI (frequency of outages) values, SAIDI or its CAIDI (duration of outages). The values are estimated based on type of customer (residential, commercial, industrial) and estimates values for each state individually. Calculating a 22-minute reduction in CAIDI for Rhode Island Energy's mix of residential versus commercial & industrial customers resulted in savings of approximately $11.9 million/year ($2022).

The second Customer benefit estimated by Rhode Island Energy, but not included in the National Grid Updated AMF Business Case involved customers' bill savings from reducing energy as part of the Energy Insights program. With the information from AMF meters, both Rhode Island Energy and the National Grid Updated AMF Business Case estimated that customers who participated in the Energy Insights program could save 1.5% of their energy overall. The National Grid Updated AMF Business Case estimated the energy cost and several societal savings associated with the reduced energy use but did not calculate the reduction in electricity bills that participating customers would experience. Rhode Island Energy estimated the overall bill savings participating customers would achieve with that 1.5% savings (less the energy cost savings to avoid double counting). These two benefits resulted in significantly higher Customer benefits.

Societal benefits are significantly higher for Rhode Island Energy than for National Grid due to significantly higher avoided CO2 costs being developed as part of the AESC 2021 report than for the AESC 2018 report. Table "ES-Table 4: Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #4 versus AESC 2018"[53] from the AESC 2021 report shows a 66% increase in the avoided costs of non-embedded GHG costs. However, although the CO2 benefits were significantly higher in AESC 2021, many of the other avoided costs in AESC were lower. The ultimate result was no change in the benefits calculated

[53] AESC 2021 Report, Executive Summary, p. 8, by Synapse Energy Economics, Inc. Link: AESC_2021_.pdf (synapse-energy.com).

using AESC 2018 versus AESC 2021. This is discussed more fully in the sensitivities discussion below.

11.3 AMF BCA Approach

In developing the BCA, Rhode Island Energy built upon the BCA included in the National Grid Updated AMF Business Case. National Grid's BCA was thorough and vetted extensively with Rhode Island stakeholders; therefore, Rhode Island Energy was able to realized efficiencies by starting with National Grid's work. Rhode Island Energy enhanced the BCA with data and experience from PPL's implementation of AMI meters in Pennsylvania several years ago. Additionally, the costs and benefits developed for the National Grid Updated AMF Business Case were developed in 2018, so Rhode Island Energy reviewed all costs and benefits and updated where necessary to reflect current values.

Rhode Island Energy's AMF Project team also worked with key internal and external business groups to conduct the BCA, including PPL, PPL's Kentucky subsidiaries ("LG&E/KU"), suppliers, industry experts, and Grid-X Partners. Over the course of the evaluation the team: (1) conducted workshops with key internal and external personnel; (2) gathered data to refine the scope of the AMF investment; (3) gathered relevant use cases from across the industry; (4) evaluated pertinent PPL operational data pre- and post-AMF implementation; (5) conducted extensive independent research on different aspects of the benefits and costs; (6) developed and finalized the key benefits of the BCA; and (7) validated the results. The results are described below followed by a more detailed discussion on how the costs and benefits were developed.

11.3.1 General Assumptions

The baseline used by Rhode Island Energy is meeting the Climate Mandates using AMR meters as compared to using AMF meters. All the benefits are calculated based on the efficiencies, additional functionalities, and avoided costs that can be achieved with AMF meters that cannot be achieved with AMR meters.

In an analysis as complex as the AMF BCA, there are literally thousands of different assumptions that come from dozens of different sources and internal calculations. Rhode Island Energy relied on the foundation of the analysis developed in the National Grid Updated AMF Business Case and, in some cases where the benefits were very small, Rhode Island Energy has used those estimates directly.

Where the benefits were significant or where there was updated information, Rhode Island Energy has recalculated the value of the benefits. Since the National Grid Updated AMF Business Case was developed circa 2018-2019, additional information has become available. This additional information includes but is not limited to:

- Updated 2021 AESC Avoided Cost report developed by Synapse,
- Updated peak energy and DER forecasts developed for Rhode Island in November 2021 and subsequent forecasts developed specifically for the GMP (which comply with Rhode Island's Climate Mandates),
- Additional information from the U.S. government on electric vehicle performance and adoption,
- Results from Rhode Island's Electrifying Transportation pilot,
- Rhode Island's actual progress on electrifying transportation,
- ISO-NE's 2050 study on implementing the clean energy goals across all of New England, and
- ISO-NE's May 1, 2022 experience with the lowest load they have ever experienced due to increased penetration of DERs.

11.4 Docket 4600 and the Rhode Island Test

The cost-effectiveness test on which the Docket 4600 Framework is based is known as the "Rhode Island Test." The Rhode Island Test considers benefits to the power system, the customer, and certain societal impacts. Because the Rhode Island Test is intended for evaluating a variety of programs, the Docket 4600 Framework includes a wide array of categories for consideration – some of which will be relevant depending on the proposal. In this Section, the Company explains how it applies the Docket 4600 Framework for the purposes of this updated AMF Business Case.

The Docket 4600 Framework attempts to quantify whether the state of Rhode Island will be better off adopting a proposed program. The benefits assessed under the Docket 4600 Framework include operational utility benefits, customer benefits, reductions in resource requirements (e.g., transmission and distribution, generation capacity, and energy use) and reductions in externalities such as carbon emissions. Expenses borne by the utility or its customers appear as costs in the BCA. Transfers of money between different customer groups are internal to this cost definition and are not included in Net Benefit calculations or in BCA ratios, although these transfers are generally going from customers who are not paying their fair share for electricity to those customers who are paying extra as a result of theft/undermetering. They are presented as part of the analysis to demonstrate an additional benefit to having AMF meters, particularly from an equity perspective.

The benefit categories used throughout this section are based on AMF capabilities, such as the ability to read meters remotely or implement TVR for mass market customers. To tie these benefit categories to the more generalized Docket 4600 Framework, Figure 11.6 lists the AMF benefits associated with each quantified Docket 4600 category. Along with this listing are the values in $NPV millions of dollars for each Docket 4600 category calculated in the BCA, broken out by the Opt-In versus Opt-Out categories.

Figure 11.6: Docket 4600 Framework categories quantified in the BCA model

Figure 11.6 Docket 4600 Table November 12, 2022			
Docket 4600 Category	NPV ($M)		AMF Benefits in BCA
	Opt-In	Opt-Out	
Power Sector: Distribution Delivery Cost	$114.81	$114.81	Avoided Sensors Avoided AMR Cost Reduced Personnel
Power Sector: Distribution Delivery Safety	$0.00	$0.00	Damage Claims: Unable to Verify
Customer: Non-Participant Rate/Bill Impacts	$0.00	$0.00	Calculated Separately
Societal: GreenHouse Gas (GHG) Externality Cost	$158.32	$159.71	Reduced Truck Rolls, VVO/CVR EV TVR, Whole House TOU, Energy Insights
Societal: Non-GHG Externality Cost	$0.55	$0.68	Whole House TOU, VVO/CVR Energy Insights, EV TVR
Societal: Public Health	$1.78	$3.21	Whole House TOU, VVO/CVR Energy Insights, EV TVR
Power Sector: Energy Savings	$51.02	$56.26	VVO/CVR, Energy Insights Whole House TOU, EV TVR
Power Sector: GHG Compliance Savings	$23.03	$23.32	Whole House TOU, VVO/CVR Energy Insights, EV TVR

Figure 11.6 (continued): Docket 4600 Framework categories quantified in the BCA model

Power Sector: Retail Supplier Risk Premium	$0.00	$0.00	Captured in Energy Savings
Power Sector: Renewable Energy Credit (REC) Value	$0.00	$0.00	Captured in Energy Savings
Power Sector: Distribution Savings	$5.59	$22.66	Whole House TOU, VVO/CVR Whole House CPP, EV TVR
Power Sector - Transfer: Low Income	$42.35	$42.35	Meter Accuracy Theft Reduction
Societal: Economic Development	$115.86	$115.86	Sensitivity
Power Sector: Capacity Savings	$66.92	$264.35	EV TVR, Whole House CPP, VVO/CVR
Power Sector: Transmission Savings	$88.90	$364.72	Whole House CPP, VVO/CVR
Power Sector: DRIPE Savings*	$4.47	$13.00	Whole House TOU, VVO/CVR Energy Insights, EV TVR
Societal: Cross-DRIPE Savings*	$0.58	$0.75	Whole House TOU, VVO/CVR Energy Insights, EV TVR
Customer: Reliability & Resilience Impacts	$169.19	$169.19	Outage Notification
Customer: Customer Bill Savings	$44.02	$44.02	Energy Insights
* Demand Reduction Induced Price Effect (DRIPE)			

11.5 Benefit Calculations and Results

Benefits and costs were estimated over a 20-year period, both in nominal values and in Net Present Values ($2022 NPVs). Both benefits and costs were broken into capital expenses (“Capex”) and operational expenses (“OpEx”). To develop NPVs, Rhode Island Energy used its post-tax Weighted Average Cost of Capital (“WACC”) at 6.97% to calculate the Costs and the Utility Savings. Rhode Island Energy used a societal discount rate of 3% to calculate the NPVs of the Direct Customer Savings and the Societal Savings. For benefits that utilized avoided costs from the Synapse AESC 2021 report, a different approach was taken. The values in the AESC 2021 report are expressed in $2021 (real) regardless of the year for which they are estimated. Using those values directly resulted in summing to the NPV (in $2021) rather than summing to nominal dollars. To determine the benefits in nominal dollars, the AESC 2021 values were increased by 2%/year.

Benefits were placed into three categories: Utility Savings, Direct Customer Savings and Societal Savings. Utility Savings include those savings that are more direct savings to the utility and, ultimately, to the Rhode Island Energy customers. Direct Customer Savings include savings that go to particular groups of customers, who, in this analysis, include customers who have an outage or participate in the Energy Insights program. Societal Savings include costs that are incurred by society as a whole by the use of electricity but are not included (“embedded”) in the price of electricity that customers pay.

Specifically, the Utility Savings category includes:

- Avoiding replacement of end-of-life meters with new AMR meters,
- Reducing the number of meter personnel (meter readers, meter investigation personnel) needed,
- Energy and capacity savings associated with VVO,
- Energy Insights savings,
- Energy and capacity savings associated with TOU rates,
- Avoided transmission and distribution costs resulting from VVO, Energy Insights and TOU rates, and the Demand Reduction Induced Price Effect ("DRIPE") benefits where applicable.

Many of the Utility benefits result from remote connect / disconnect for electric meters, saving truck rolls, reducing customer calls, and providing increased operational flexibility. A significant number of the benefits also result from the need to replace Rhode Island Energy's existing AMR meters because they are at the end of their design life and cannot provide necessary functionalities.

Direct Customer Benefits includes two benefits that the National Grid Updated AMF Business Case did not include in the BCA. The first is the customer electricity bill savings as a result of customers saving 1.5% of their electricity usage as a result of the AMF meters and Energy Insights program. The second is a benefit resulting from faster notification of power outages from the Last Gasp function of the AMF meters. In Pennsylvania, PPL has experienced a 22-minute faster notification of power outages with AMF meters than with waiting for customers to call in an outage. This results in customers having their power back on 22 minutes faster even though the time to restore the power does not change.

Societal Benefits include savings from non-embedded CO_2 and NO_x reduction costs, Public Health benefits, and cross-DRIPE energy savings.

There are six "Tier 1" benefits that were described in the National Grid Updated AMF Business Case and for which the Company is committed to measuring and returning 80% of the benefits directly to the customers. These six benefits are:

1. AMR Meter Reading Savings;
2. AMR Meter Reading Vehicle Savings;

3. Reduced Meter Investigations;

4. Remote Metering Benefits;

5. FCS Costs; and

6. Interval Meter Reading Costs.

The total estimate for these Tier I benefits is $88.4 million nominal and $39.4 million NPV.

11.5.1 Benefit Breakdown

As part of this BCA, Rhode Island Energy considered approximately 80 different benefits. These benefits were subsequently sorted into four Categories; three were discussed above and included in the calculation of Net Benefits and BCA ratios; the last one, Transfers, was calculated but not included in the BCA results. Figure 11.7 shows the total benefits by each category in $Nominal and $2022 NPV.

Figure 11.7: Benefits by Category

Benefits by Category		
Rhode Island Energy	Nominal ($M)	NPV ($2022M)
As of November 12, 2022		
Utility Savings	$ 529.7	$ 354.7
Customer Savings	$ 314.5	$ 213.2
Societal Savings	$ 215.1	$ 161.2
Total BCA Savings	$ 1,059.3	$ 729.2
Transfer Payments	$ 92.1	$ 42.3

Each benefit was also assigned a Benefit Program, a Benefit Type and a Rate Type. The Benefit Program designations are meant to describe, generally, what programs and activities of the utility are giving rise to the benefits. The Benefit Programs include:

1) Direct Customer Benefits,

2) Energy Insights savings,

3) Volt Var Optimization/Conservation Voltage Reduction ("VVO/CVR") savings,

4) Electric Vehicle/Time Varying Rates ("EV/TVR") savings,

5) Avoided AMR Costs savings

6) Remote Metering Capabilities

7) Avoided Digital Signal Processor ("DSP") Sensors,

8) Whole House Time-of-Use/Critical Peak Pricing ("TOU/CPP") savings,

9) Reduced Field Investigations, and

10) Reduced AMR Meter Readers.

Figure 11.8: Rhode Island Energy Benefits Included in BCA by Program Category

RIE Benefits Included in BCA Sorted by Program Category		
As of November 12, 2022	Nominal ($M)	NPV ($2022 M)
Direct Customer Benefits	$ 314.5	$ 213.2
VVO/CVR Benefit	$ 168.9	$ 126.1
Energy Insights Savings	$ 147.6	$ 110.7
Whole House TOU/CPP - Opt-In (20%)	$ 115.1	$ 84.1
EV/TVR Benefit - Opt-In (20%)	$ 112.4	$ 79.5
Avoided AMR Costs	$ 89.5	$ 61.7
Remote Metering Benefits	$ 56.1	$ 25.1
Avoided DSP Sensors	$ 23.2	$ 14.4
Reduced Field Investigations	$ 17.2	$ 7.7
AMF Meter Reading Benefits	$ 14.8	$ 6.7
Total RIE Benefits included in B/C Ratios	$ 1,059.3	$ 729.2

Each of the benefits shown in Figure 11.8 are discussed more fully below. In addition to the benefits that Rhode Island Energy included in the BCA, the Company calculated two Transfer Payment benefits, Electricity Theft Reduction and Electromechanical Meter Accuracy. These are also discussed more fully below.

The Benefit Types are designed to describe what particular type of benefit is being evaluated, e.g., reduced personnel costs v. transmission savings v. energy cost savings v.

value of CO2 reductions. Finally, each benefit was also assigned a Rate Type. The Rate Types are:

1) Capital Expenditures (“Capex”),

2) Combination of Capital Expenditures and O&M Expenditures (“Capex/OpEx”),

3) Cost of Removal (“COR”),

4) Customer Benefits,

5) Operational & Maintenance Expenditures (“OpEx”),

6) Revenue, and

7) Societal Benefits.

These different categorizations are designed to enable stakeholders and the PUC to understand the benefits from different perspectives. For example, a programmatic perspective might be: “How many benefits are coming from the Energy Insights program?” While a Benefit Type perspective might be: “How many of the total savings are coming from Capacity savings?”

11.5.2 Direct Customer Benefits

The business case identifies two Direct Customer Benefits: Energy Insights/Bill Alert Electricity Bill Savings and Faster Customer Outage Notification. Figure 11.9 depicts the savings from each of these benefits.

Figure 11.9: Direct Customer Savings

Direct Customer Benefits		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
Faster Outage Notification	**$ 243.79**	**$ 169.19**
Electric Bill Reductions: Energy Insights	**$ 70.73**	**$ 44.02**
Total Direct Customer Benefits	**$ 314.51**	**$ 213.22**

Faster Outage Notification is the result of AMF meters’ ability to notify Rhode Island Energy operations immediately when an outage occurs. The control center is immediately notified there is an outage, including which customers are out; that data is promptly processed to provide a complete graphical picture of the outage, which serves to expedite the entire outage restoration process. Today, customer calls are used as the source of information, and customers may not be home or may fail to realize the need to report the outage to the utility, resulting in delays in the utility knowing there is an outage. Based on PPL's experience in Pennsylvania, utility operators receive notification from the meters 22 minutes faster than when relying on customer calls to report the outage. With AMF meters, crews are dispatched when they get the outage notification from the meter, rather than waiting for the customer to call in. The time savings on dispatching crews does not impact the time it takes to fix the outage, but it does impact the customer's outage time. Rhode Island Energy used the Department of Energy's Interruption Cost Estimator program to estimate the value of this 22-minute savings and included it as one of the benefits.

In addition, because of the data sent to the control center and GIS mapping, operators will know the size, location, and extent of the outage, enabling the dispatch of the correct vehicles and equipment. This benefit was not estimated as part of this AMF filing but will be estimated in the Grid Modernization Plan filing.

The second Direct Customer Benefit is the energy bill savings experienced by participants in the Energy Insights program. Rhode Island Energy estimates that customers who have near real-time information on their electricity usage will reduce that usage, particularly as the Company develops phone apps and more sophisticated energy information to share with customers. Rhode Island Energy estimates that 30% of residential customers and 25% of commercial customers will reduce their energy use by 1.5% because of the information and apps they will have with AMF meters. The utility will experience energy cost savings due to these reductions because they will not have to buy as much energy on the market. The energy savings accrue to the utility as a whole and those savings are included in the Utility Benefits. Participating customers will save on their electricity bills. Rhode Island Energy used a rate of $0.22/kWh escalated by 1.68% starting in 2026 to calculate the savings participating residential customers would save. Similarly, the Company used a rate of $0.159/kWh escalated by 0.99% starting in 2026 to calculate the savings for participating commercial customers. These estimates do not include the recent price increases but are based on historical growth rates. Rhode Island Energy calculated the amount customers would save on their bills and included this amount in Direct Customer Benefits after subtracting out the utility's energy cost savings to avoid double counting of benefits.

11.5.3 Volt/Var Optimization ("VVO") Opportunities/Conservation Voltage Reduction

As detailed in Section 3, distribution system operators of the electric system in Rhode Island currently have very limited awareness of high or low voltage conditions across distribution feeders, reverse flow information, and distribution transformer loading issues. AMF meters will provide the electric distribution operators with critical, real-time situational awareness of the electric networks. Alarms and near real-time data will be sent from AMF meters to the MDMS, which will feed business and operational platforms/systems to provide system visibility to the operators in a usable format.

This data will include locational knowledge of energy usage, voltage, current, flow, on/off status, and DER status at each meter; it will provide the opportunity for VVO, resulting in CVR. Rhode Island Energy estimates that VVO as a result of AMF meters would result in 0.5% energy savings overall and 0.167% peak savings. The same report of surveys of 52 utility programs referenced above in the Energy Insights savings discussion also showed a 1%-4% savings due to VVO/CVR as a result of AMF.[54] Rhode Island Energy also had a VVO/CVR pilot at three substations. The pilot was evaluated by a third-party vendor and, for two of the three substations, the kWh savings on each feeder ranged from 1.3%-3.5% on each feeder. The weighted average savings for one of the substations was 1.5% and the weighted average savings for the other substation was 3.5%.

The 0.5% energy savings results in fuel savings to the utility and it also results in CO_2, NOx and Public Health benefits. The peak savings results in System Capacity savings, Transmission and Distribution Capacity benefits, and Capacity Reduction Induced Price Effect ("DRIPE") benefits. Figure 11.10 depicts the benefit values created by VVO.

[54] Rachel Gold, Corri Waters, Dan York, *Leveraging Advanced Metering Infrastructure To Save Energy*, American Council for an Energy-Efficient Economy (revised January 27, 2020).

Figure 11.10: Volt/Var Optimization ("VVO") and Conservation Voltage Reduction ("CVR") Savings

VVO/CVR Benefit				
As of November 12, 2022	**Nominal ($M)**		**NPV ($M)**	
Non-Embedded CO2 Benefit: VVO/CVR	$	108.78	$	81.69
Energy Savings: VVO/CVR	$	34.06	$	25.61
Monetized CO2 Benefit: VVO/CVR	$	16.05	$	11.96
Public Health Benefit: VVO/CVR	$	0.50	$	0.37
Trans Capacity Benefit: VVO/CVR	$	4.16	$	3.05
System Capacity Benefit: VVO/CVR	$	3.07	$	2.25
Capacity DRIPE Benefit: VVO/CVR	$	0.46	$	0.17
Energy DRIPE Benefit: VVO/CVR	$	0.85	$	0.42
Energy Cross DRIPE Benefit: VVO/CVR	$	0.38	$	0.19
Non-Embedded NOX Benefit: VVO/CVR	$	0.31	$	0.24
Dist Capacity Benefit: VVO/CVR	$	0.27	$	0.20
Total VVO/CVR Benefits	**$**	**168.89**	**$**	**126.14**

There are a number of different types of benefits resulting from VVO/CVR benefits. Some are Utility benefits that flow back to customers in the near term, including Energy Savings, System Capacity benefit, and Monetized CO2 benefit. Some are Utility benefits that flow back to customer over time. These include Energy Demand Reduction Induced Price Effect ("DRIPE") benefit, the Capacity DRIPE benefit, and the Distribution Capacity benefit. Transmission Capacity benefits flow proportionally back to customers over time. Societal benefits do not actually flow back to customers as these are costs that are either incurred costs not included in the electricity price or, in the case of Cross-DRIPE benefits, savings that accrue to customers outside of Rhode Island Energy. The Societal benefits include Non-Embedded CO2 and NOx benefits, and Public Health. These are costs to society associated with electricity production, distribution and use that are not captured in the price of electricity.

11.5.4 Energy Insights/Savings

As discussed above, Rhode Island Energy estimates that customers who participate in the Energy Insights program will reduce their electricity consumption by 1.5% when they have near real-time usage information and phone apps to adjust their use. The Company estimates that 30% of residential customers and 25% of commercial customers will participate in the program.

The 30% residential participation and the 25% commercial participation were based on 50% participation in PPL Electric's Customer Portal, an evaluation of National Grid's Rhode Island energy efficiency programs from 2009-2015, and evaluations of Rhode Island Energy's Home Energy Reports Programs. The 1.5% savings was developed through industry research, including one report that surveyed results from 52 utilities across the U.S. who have installed AMF meters and found savings of 1-8%,[55] and a review of the savings from Rhode Island Energy's Home Energy Reports programs.

In terms of the amount of energy saved, National Grid had two estimates of energy savings – 1.5% and 3.5%. For programs involving near real-time information and behavioral feedback, Rhode Island Energy decided to use the lower of the two estimates used by National Grid – 1.5% - to be conservative and to reflect Rhode Island's long and successful history of achieving energy consumption reductions through energy efficiency programs. Figure 11.11 outlines the savings associated with the Energy Insights program.

Figure 11.11: Energy Insights Benefits

Energy Insights Savings		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
Non-Embedded CO2 Benefit: Energy Insights	**$ 99.53**	**$ 74.88**
Energy Savings: Energy Insights - Electric	**$ 31.10**	**$ 23.42**
Monetized CO2 Benefit: Energy Insights	**$ 14.58**	**$ 10.86**
Public Health Benefit: Energy Insights	**$ 0.45**	**$ 0.34**
Energy DRIPE Benefit: Energy Insights	**$ 1.18**	**$ 0.71**
Energy Cross DRIPE Benefit: Energy Insights	**$ 0.47**	**$ 0.29**
Non-Embedded NOX Benefit: Energy Insights	**$ 0.28**	**$ 0.22**
Total Energy Insights Savings	**$ 147.60**	**$ 110.73**

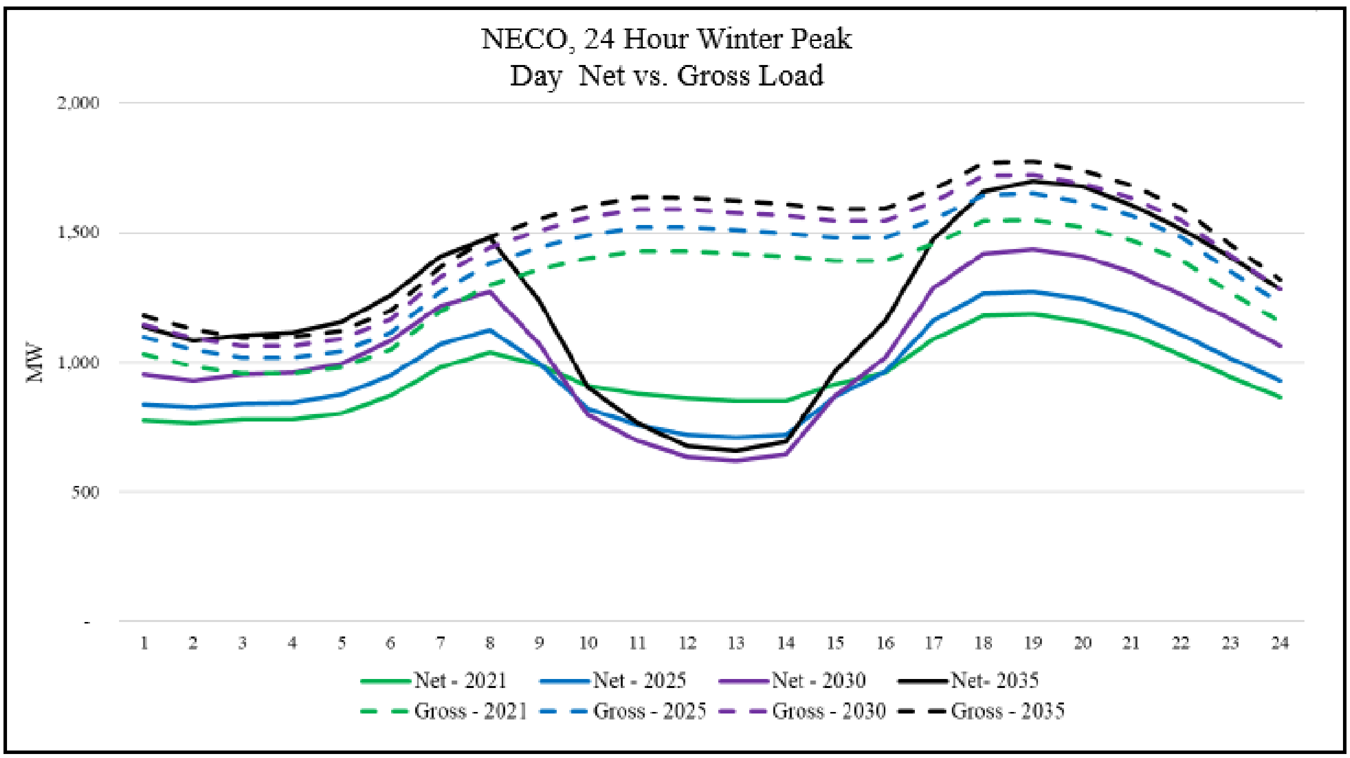
11.5.5 Future Time-Varying Rate Capability for Whole House

Rhode Island Energy estimated savings associated with using AMF meters for TVR and has made a commitment to return to the PUC in the future with a proposal for TVR.

55 *Id.*

While some very basic TVR or TOU rates can be implemented for customers without smart meters, these TVR/TOU programs are extremely limited. For example, a program might have higher prices in the summer than in the winter or higher prices for a set period of the day (although AMR meters are incapable of enabling daily TOU rates without some additional equipment.) These types of programs have been discussed and implemented for decades and have not provided significant savings to customers and have not had wide adoption. In addition, with the increased adoption of DERs, renewables and electric vehicles, the old TOU constructs will no longer apply. The load shapes experienced by the utilities are changing significantly and it is much more difficult to predict when the best time is to implement higher versus lower prices. Below is an example of how the load shapes are changing. Figure 11.12 shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. When the variable performance of wind is added, the load shape becomes even more unpredictable. When electricity use/production is changing so dynamically, TVR will be very helpful in managing the grid, but traditional AMR meters do not work for TVR because TVR need to be flexible.

Figure 11.12: Projected Load Shapes with Distributed Energy Resources ("DERs")



The Whole House TOU/CPP rate construct used in the BCA consists of a two-period (on-peak, off- peak) TOU rate and a separate CPP rate. The TOU rate is based on, and captures variation in, Independent System Operator-New England ("ISO-NE") energy market prices. The CPP rate includes all generation capacity costs, allocated over 70 hours per year. Based on the Company's expected duration of CPP events, this equates to approximately 12 to 15 events per year.

To calculate energy benefits from a Whole House perspective, Rhode Island Energy used a Time-of-Use ("TOU") construct to calculate energy savings associated with shifting electricity use from on-peak hours to off-peak hours. For Whole House peak savings, Rhode Island Energy assumed that only residential customers would participate and that participating customers would save 20% of their peak electricity usage on a Critical Peak Pricing rate. This approach results in system capacity savings, transmission and distribution savings, and Demand Reduction Induced Price Efficiency ("DRIPE") savings. Figure 11.13 shows the savings estimated from Whole House TOU/CPP rate constructs.

Figure 11.13: Whole House TOU/CPP Benefits

Whole House TOU/CPP - Opt-In (20%)		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
Trans Capacity Benefit: Whole House CPP	$ 58.72	$ 43.25
System Capacity Benefit: Whole House CPP	$ 38.84	$ 28.58
System Capacity Savings: Whole House Time-of-Use (TOU	$ 7.10	$ 5.23
Dist Capacity Benefit: Whole House CPP	$ 3.40	$ 2.51
Capacity DRIPE Benefit: Whole House CPP	$ 3.42	$ 2.48
Energy Shift Benefits: Whole House Time-of-Use (TOU)	$ 1.26	$ 0.48
Trans Capacity Benefit: Whole House TOU	$ 0.97	$ 0.71
Public Health Benefit: Whole House TOU	$ 0.41	$ 0.28
Non-Embedded CO2 Benefit: Whole House TOU	$ 0.41	$ 0.28
Energy DRIPE Benefit: Whole House TOU	$ 0.13	$ 0.06
Energy Cross DRIPE Benefit: Whole House TOU	$ 0.06	$ 0.03
Dist Capacity Benefit: Whole House TOU	$ 0.26	$ 0.19
Monetized CO2 Benefit: Avoided Energy - Whole House T	$ 0.09	$ 0.04
Non-Embedded NOx Benefit: Whole House TOU	$ 0.04	$ 0.03
Total Whole House TOU/CPP	**$ 115.10**	**$ 84.13**

11.5.6 Electric Vehicle Time-Varying Rates Benefits

AMF meters for electric customers provide the functionality to efficiently implement TVR in the future. TVR will be needed to deal with (1) DERs, which will be producing at different times and significantly changing the load shape, and (2) increasing penetrations of EVs. There are many different approaches to developing TVR structures ranging from a simple TOU construct with higher rates for specific peak periods of the day to charging customers varying real-time rates on an hourly basis. Some TVR involve developing significantly higher rates during critical peaks on the system – CPP. The benefits shown below were derived by implementing TVR for the Whole House. This section briefly describes the major assumptions Rhode Island Energy used for estimating benefits from TVR and presents the resulting savings. Much more detail on TVR and the Company's assumptions are presented in Section 13.

Rhode Island Energy estimated TVR benefits based on both an Opt-In approach and an Opt-Out approach. In an Opt-In approach, customers are offered the rate and must actively choose to be on the rate to participate. In an Opt-Out approach all customers are placed on the rate and given the option to remove themselves from the rate. Many factors affect the number of customers who enroll in TVR. Regulatory policy will dictate whether TVR will be offered on a default service basis (opt-out) or not (opt-in). The BCA presents results on both opt-out and opt-in bases, assuming 85% and 20% participation, respectively.

With the advent of EV charging on the distribution system and increasing quantities of Solar PV behind the meter, low-cost pricing hours may occur in the middle of the day, at night, or other times. It will be very important for overall transmission and distribution reliability and resource adequacy that consumers are incentivized to charge their EVs during low-cost operating hours.

The Company estimated the energy, capacity, transmission and distribution savings that would result from EVs shifting some charging from the peak hour to off-peak hours and also the impacts of participating EV owners reducing their EVs' contribution to the system peak. As can be seen in the figures above and below, the total energy savings due to TOU/CPP rates for EVs and Whole House TVR is much smaller than the capacity, transmission or distributions savings. Figure 11.14 shows the benefits calculated for EV TVR.

Figure 11.14: Electric Vehicle Time-Varying Rate Benefits

EV/TVR Benefit - Opt-In (20%)		
As of November 12, 2022	Nominal ($M)	NPV ($M)
Trans Capacity Benefit: EV TVR	$ 58.90	$ 41.89
System Capacity Benefit: EV TVR	$ 43.41	$ 30.86
Dist Capacity Benefit: EV TVR	$ 3.79	$ 2.70
Energy Shift Benefits: EV TVR	$ 2.08	$ 1.51
Capacity DRIPE Benefit: EV TVR	$ 1.32	$ 0.50
Public Health Benefits: EV TVR	$ 1.15	$ 0.79
Non-Embedded CO2 Benefit: EV TVR	$ 1.13	$ 0.78
Monetized CO2 Benefits: EV TVR	$ 0.26	$ 0.17
Energy DRIPE Benefit: EV TVR	$ 0.22	$ 0.12
Non-Embedded NOX Benefit: EV TVR	$ 0.10	$ 0.07
Energy Cross DRIPE Benefit: EV TVR	$ 0.09	$ 0.07
Total EV/TVR Benefits	**$ 112.45**	**$ 79.46**

11.5.7 Avoided AMR Electric Meter Replacement Costs

The bulk of Rhode Island Energy's AMR electric meters are at or near the end of their useful life and have been designated for replacement. As a result, the AMF project achieves a benefit of avoided cost for future replacement of these meters. The cost of replacing these electric meters is included in the overall project cost. The cost of AMR electric meter replacement is treated as an avoided cost in the AMF BCA analysis, because in lieu of an approved AMF program the Company would be required to replace the AMR electric assets.

There are two ways to account for the avoided costs of the AMR meters. The first is to take an incremental approach – if the AMR meter costs $100 and the AMF meter costs $110, you would only count the $10 incremental costs in the costs of the program and you would not count the replacement of the AMR meters as a benefit. The second approach is to include the total cost of the AMF meters and associated costs into the cost portion of the Benefit-Cost model and then take the dollars that would have been spent on AMR meters as a benefit.

Rhode Island Energy decided to use the second approach for a number of reasons. First, while it may seem that the incremental approach is simpler, accounting for all of the costs associated with replacing AMR meters and matching them with incremental costs of using AMF meters is complicated. Second, Rhode Island Energy has agreed not to exceed the costs set forth in the National Grid Updated AMF Business Case – $289.4 million nominal. Ensuring the Rhode Island Energy costs would not exceed this is much more straightforward using the full costs in the benefits and costs than it would be using the incremental costs. Finally, Rhode Island Energy will be using the cost model developed as part of this filing to track its costs. That also would be much more complicated to do and to explain if one were to take a "netting" approach to accounting for AMF versus AMR meters.

There are numerous benefits that were estimated associated with Avoided Electric Meter Replacement Costs and many of those benefits were very small. Rhode Island Energy used the same values for these benefits that National Grid used in their initial filing with the exception of Avoided Electric Meter Replacement and Avoided Electric Meter Installation Cost – Capex and Opex portions. The benefits for this category are shown below in Figure 11.15.

Figure 11.15: Benefits from Avoided AMR Costs

Avoided AMR Costs		
As of November 12, 2022	Nominal ($M)	NPV ($M)
AMR Meter Replacement	$ 50.62	$ 33.44
AMR Electric Meter Installation Cost - Capex Portion	$ 16.11	$ 10.61
Customer Engagement Plan Cost	$ 3.05	$ 2.35
AMR Internal Project Management Leadership - Capex Porti	$ 2.85	$ 2.33
CMS Deployment Coordination Labor Cost	$ 2.54	$ 2.04
CMS Deployment Center, Facility Cost	$ 2.43	$ 1.92
CMS Back Office & Clerical Cost	$ 2.32	$ 1.87
AMR Demonstration Period Cost	$ 1.34	$ 1.09
AMR Inventory Equipment Cost	$ 1.08	$ 0.76
Call Center Implementation Cost	$ 1.06	$ 0.84
Account Maintenance & Operations Implementation Cost	$ 1.05	$ 0.84
AMR Electric Meter Installation Cost - Cost of Removal (CO	$ 0.92	$ 0.63
CMS Field Installer Initial Training	$ 0.92	$ 0.78
AMR Internal Project Management Leadership - Opex Portio	$ 0.90	$ 0.84
FCS Costs	$ 0.67	$ 0.29
Interval Meter Reading Costs	$ 0.64	$ 0.30
AMR Electric Meter Installation Cost - Opex Portion	$ 0.50	$ 0.33
Service Representative Tools / Uniform Cost	$ 0.25	$ 0.20
CMS Cellular Communication Cost	$ 0.11	$ 0.09
MDS System Development Testing	$ 0.07	$ 0.06
Handheld Devices Cost	$ 0.07	$ 0.05
Installed Meter Quality Checks	$ -	$ -
Customer Engagement Plan Labor Cost	$ -	$ -
Total Avoided AMR Costs	**$ 89.49**	**$ 61.68**

11.5.8 Remote Meter Reading Benefits

AMF meters will also be equipped with a remote service switch which allows for remote connects and disconnects for electric meters. This capability will eliminate labor costs and “truck rolls” for:

- Scheduled turn-on activity (move ins/outs),
- Any subsequent trips for connect or disconnect due to access issues after initial attempt, and
- Scheduled disconnects due to non-payment/replevin action.

Eliminating the need to send crews to customers' residences for these types of issues will save significant personnel and associated equipment costs. The savings from the remote meter switch are shown in Figure 11.16. These benefit savings were calculated using experience from PPL in terms of the relative costs for these activities before their AMI meters were installed and after their AMI meters were installed.

Figure 11.16: Remote Meter Reading Benefits

Remote Metering Benefits				
As of November 12, 2022	Nominal ($M)		NPV ($M)	
Remote Metering Benefits	$	55.63	$	24.73
Non-Embedded CO2 Benefit: Remote Metering	$	0.47	$	0.33
Total Remote Metering Benefits	**$**	**56.10**	**$**	**25.06**

11.5.9 Avoided Digital Signal Processor ("DSP") Sensors

In addition to the Avoided AMR Costs, Rhode Island Energy estimated that a significant amount of distribution feeder sensors can be avoided due to the information that will be available from the AMF meters. Where, with AMR meters, three sensors would have to be deployed per feeder, AMF meters require only one sensor per feeder. The total number of feeders is 484 and, of these, 45 already have DSP sensors, leaving 439 of the feeders needing sensors. The capital and installation cost of DSP sensors, and related O&M costs total approximately $22,000/sensor. Figure 11.17 shows the benefits from the reduced need for sensors.

Figure 11.17: Avoided Digital Signal Processor ("DSP") Sensors Benefit

DSP Sensors				
As of November 12, 2022	Nominal ($M)		NPV ($M)	
Avoided DSP Sensors	$	23.18	$	14.36

11.5.10 Meter Investigation Efficiencies

Meter investigation efficiencies are realized through reduced field services enabled by the remote metering capabilities provided by AMF. Today, the utility responds to a significant number of outage reports per year that are determined to be "false outages." The utility must respond with crew and truck rolls to high voltage, low voltage, and flicker claims from customers. These "false outages" are often not associated with electric service being provided to the premise and instead require an electrician to resolve an internal electrical problem. With the deployment of AMF meters and the information they provide, office personnel can determine meter status and avoid additional crew and truck roll costs. Also, as a result of improved monitoring and measurement capabilities, real power quality problems may often be identified even before a customer experiences an issue.

Rhode Island Energy applied PPL's experience with the implementation of AMF meters in Pennsylvania to calculate the benefits associated with reducing these activities. In Pennsylvania, PPL has been able to reduce Meter Investigation and Support personnel much more than estimated in the National Grid Updated AMF Business Case. As a result, this business case reflects increased benefits in this area.

The savings for Reduced Field Services are shown in Figure 11.18 below.

Figure 11.18: Field Investigations Benefits

Reduced Field Investigations		
As of November 12, 2022	Nominal ($M)	NPV ($M)
Reduced Meter Investigations	$ 17.09	$7.63
Non-Embedded CO2 Benefit: Reduced Meter Investigations	$ 0.08	$ 0.05
Reduced Field Investigations	**$ 17.16**	**$ 7.69**

11.5.11 Meter Reading Benefits

AMF will deliver measurable benefits by automating meter reading functions. The need for drive-by meter reading will be eliminated. This will save eight Full-Time Equivalent ("FTE") positions in operations (meter readers for billing). Rhode Island Energy estimated the savings from eliminating these positions, including phone, uniform and maintenance costs for hand-held meter reading devices. In addition to the Meter Reader FTE reductions, there will be a reduced need for Meter Reading vehicles, which will also result in lower CO2 emissions.

Figure 11.19 shows the benefits related to reduced Meter Reading FTEs.

Figure 11.19: AMR Meter Reading Benefits

AMF Meter Reading Benefits		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
AMR Meter Reading Savings	**$ 11.19**	**$4.97**
AMR Meter Reading Vehicle Savings	**$ 3.20**	**$1.43**
Non-Embedded CO2 Benefit: Eliminated AMR Vehicles	**$ 0.45**	**$ 0.32**
Total AMF Meter Reading Benefits	**$ 14.84**	**$ 6.71**

11.5.12 Avoided Transmission and Distribution ("T&D") Costs

Implementing a full AMF metering and communication/IT structure will result in better visibility, reductions in electricity usage and, subsequently, reductions in transmission and distribution costs. These savings are reflected in Avoided T&D Costs. Avoided T&D costs arise from many of the benefits included in the analysis:

- The 0.167% capacity savings due to VVO/CVR,
- Whole House Time-of-Use ("TOU")/ Critical Peak Pricing ("CPP"), and
- Electric Vehicle ("EV") peak reductions due to TVR.

The avoided T&D costs are embedded in the benefits associated with the program that created the savings. Rhode Island Energy calculated benefits using information from National Grid for the coincidence of T&D peaks with the system peak and the avoided T&D costs from the 2021 AESC report.

11.5.13 Societal Benefits

Many AMF benefits translate directly into consumer reliability benefits and achievement of Rhode Island's Climate Mandates. AMF meters also will provide Societal benefits, including reductions in harmful emissions with improvements in public health. The deployment of AMF will result in emission savings and health benefits as arising from multiple functionalities they enable, such as:

- Energy Insights/Bill Alerts;
- TOU/TVR rates for EV Charging enabled by AMF meters; and
- VVO/CVR enabled by AMF meters.

The societal benefits include reduced Greenhouse Gas ("GHG") emissions, reduced NOx emissions,[56] and improved public health. Societal benefits also include Cross-DRIPE benefits, which are the electricity price reductions due to reduced energy/peak usage that accrue to the ISO-NE area outside of Rhode Island.[57] Reductions in demand create reductions in energy and capacity prices within Rhode Island and also creates some smaller reductions throughout the ISO-NE area. The reductions in the rest of the ISO-NE area are known as the Cross-DRIPE effect.

Reductions in demand create reductions in energy and capacity prices within Rhode Island and also creates some smaller reductions throughout the ISO-NE area. The reductions in the rest of the ISO-NE area are known as the Cross-DRIPE effect.

The societal benefits are shown in the tables summarizing the benefits associated with each of these functions.

11.6 Transfer Payments Benefits

Rhode Island Energy estimated two transfer benefits. These benefits are not included in the BCA but the Company calculated them to reflect benefits that will accrue to customers as a result of reduction of electricity theft and an improvement in meter accuracy. Both theft and inaccurate meters result in costs to provide electricity for which the utility does not receive payment. In the case of theft, customers are intentionally bypassing/slowing down the meter to avoid paying for all their electricity. In the case of meter inaccuracy, the customers do not know that their meter has "slowed down" but still end up using kWhs for which they do not pay. Because of how rates are set, these costs are spread across all ratepayers. Because the benefits are "transferred" from one set of customers to another they will net zero in a benefit/cost analysis. However, utilizing AMF meters will result in more equity in the system.

Figure 11.20 shows the transfer payment amounts associated with reduced electricity theft.

[56] CO2 and NOx benefits are calculated in two different categories in this analysis. The first is the direct costs paid by utilities and consumers for CO2 and NOx emissions; when emissions are reduced, the costs are also reduced. The direct cost reductions are included in Utility Savings. The second, and larger, set of savings from emissions reductions is the "Non-Embedded" emissions calculations. These calculations reflect the societal benefits of the emissions reduction that are not reflected in electricity rates.

[57] DRIPE benefits are the savings that accrue to Rhode Island customers, which are included in Utility Savings.

Figure 11.20: Reduced Electricity Theft Transfer Payment

Reduced Electricity Theft		
As of November 12, 2022	Nominal ($M)	NPV ($M)
Electricity Theft Reduction	$ 60.61	$24.46

Figure 11.21 depicts the savings realized from increased meter accuracy.

Figure 11.21: Meter Accuracy Transfer Payment

Meter Accuracy Improvements		
As of November 12, 2022	Nominal ($M)	NPV ($M)
Electromechanical Meter Accuracy	$ 31.47	$ 17.89

11.7 Development of AMF Deployment Costs

The Company developed its deployment costs using information from the National Grid Updated AMF Business Case, PPL's experience with its Pennsylvania and Kentucky AMF meter installations, and consultations with vendors and industry experts. The costs include not only the meters themselves and installation but also the communication/IT infrastructure necessary for the AMF meters to provide visibility of the system to operators, visibility of electricity use to customers and the reliability and safety benefits described above. Rhode Island Energy's design for telecom requirements is more robust than set forth in the National Grid Updated AMF Business Case because the Company believes it is necessary to provide functionality needed for electric meters and DER management. Rhode Island Energy's AMF deployment also includes more software functionality than proposed in the National Grid Updated AMF Business Case. In addition, Rhode Island Energy's cost estimate includes the cost of pre-sweeps and meter base repairs where needed, as identified in the pre-sweeps which the National Grid Updated AMF Business Case did not include.

Detailed assumptions for all the costs discussed below are included in Attachment H, which has been filed confidentially.

11.7.1 AMF Costs Included in the BCA

This evaluation includes descriptions and estimates of four major cost elements associated with AMF deployment and ongoing support: Meters; Network; Systems; and Program Costs. The assumed costs for AMF equipment, installation, and ongoing O&M

are based on proposed prices from vendors and PPL's experience in other states. These are discussed in detail in subsequent sections.

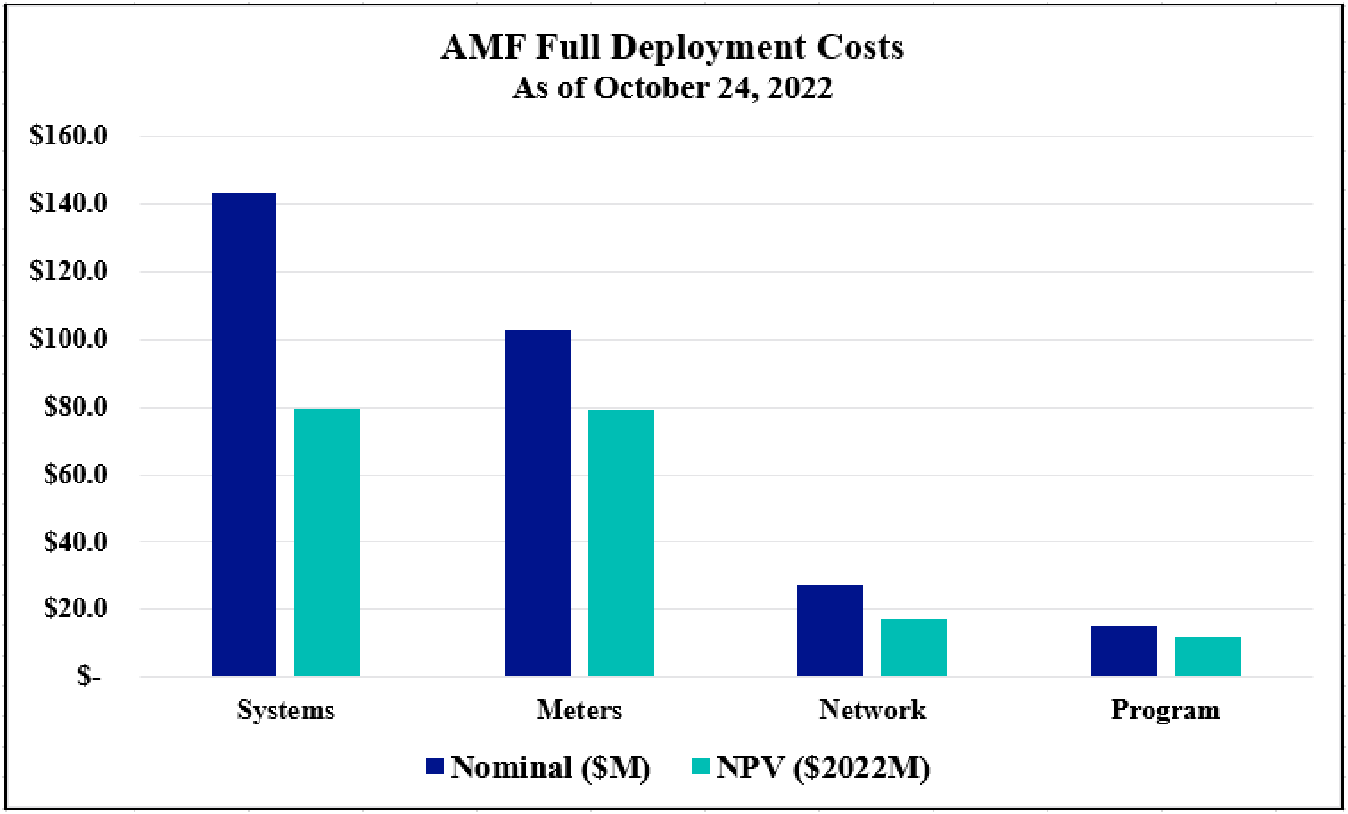
The deployment period is from 2022 to 2025. The first year involves migration of existing PPL platforms and development of IT infrastructure and systems for Rhode Island. The following years will complete the telecom network and meter deployment.

A summary of the values for each of the four primary cost categories is presented in Figure 11.22 in table form. Figure 11.23 presents the categories in graphical form. Each of the individual categories is discussed in subsequent sections.

Figure 11.22: AMF Cost Summary ($millions) – Electric

AMF Full Deployment Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($2022M)	CapEx	OpEx
Systems	$ 143.41	$ 79.52	$ 44.66	$ 98.74
Meters	$ 102.85	$ 79.29	$ 99.67	$ 3.18
Network	$ 27.49	$ 17.03	$ 14.94	$ 12.55
Program	$ 15.27	$ 12.14	$ 10.03	$ 5.24
Total AMF Costs	$ 289.01	$ 187.98	$ 169.30	$ 119.71

Figure 11.23: AMF Cost Graph ($Millions) – Electric



The overall cost of Rhode Island Energy's full deployment of AMF meters is slightly lower than the estimates of $289.4 million nominal and $192.6 million Net Present Value ("NPV") from the National Grid Updated AMF Business Case. The capital costs for the Company's program are 59% of the total cost of the program on a nominal basis. The vast majority of the costs are in the purchase and installation of the meters and in the systems development needed to use the data to manage the system.

11.7.2 Systems Costs

The Systems costs for the AMF program include the systems' stand-up and implementation, the PMO and SI vendor costs, and internal PPL labor. Systems costs comprise $143.4 million nominal ($79.5 million NPV) of the $289.0 million nominal ($188.0 million NPV) costs of the AMF system, or almost one-half of the total nominal costs. Figure 11.24 presents the Systems costs by category in table form. Figure 11.25 present the costs in graphical form.

Figure 11.24: Systems Costs by Category (Nominal $M and NPV $2022M)

Systems Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($2022M)	CapEx	OpEx
Headend	$ 65.13	$ 34.46	$ 14.52	$ 50.61
MDMS	$ 33.54	$ 16.85	$ 6.86	$ 26.68
Cust Engagement	$ 12.56	$ 7.55	$ 6.67	$ 5.89
Analytics	$ 7.30	$ 4.84	$ 3.78	$ 3.52
Steady State Ops	$ 6.30	$ 2.75	$ -	$ 6.30
Middleware	$ 4.20	$ 2.89	$ 2.76	$ 1.44
ADMS & OMS	$ 2.96	$ 1.99	$ 1.80	$ 1.17
Project Management	$ 2.80	$ 2.30	$ 2.80	$ -
Cyber Security	$ 2.78	$ 2.21	$ 2.58	$ 0.20
CSS	$ 2.71	$ 1.86	$ 1.68	$ 1.03
Grid Edge Comp	$ 1.90	$ 0.82	$ -	$ 1.90
Depl Exchange Mgt	$ 1.22	$ 0.99	$ 1.22	$ -
Total Systems Costs	$ 143.41	$ 79.52	$ 44.67	$ 98.74

The Headend, MDMS, and the Customer Engagement systems make up the bulk of the costs, totaling $111.2 million nominal and $58.9 million NPV. Those costs are 77% and 74%, respectively, of the total Systems costs. Headend includes the Headend itself, upgrades to the Headend system that will be needed in the future, and Wi-SUN, a wireless technology used for communications.

The Meter Data Management System cost includes the MDMS itself, upgrades to the system that will be needed in the future, and annual license fees for the software.

Customer Engagement costs include costs for the Customer Portal, outage alerts, GBC, bill alerts, access to near real-time data, a carbon footprint calculator, a Commercial & Industrial and multi-family portal view, and a Distributed Generation portal. All of the above programs involve costs in years 1-4. Customer Engagement costs also include costs for TVR, which occur in years 5-20. Capital expenditures are needed to stand up the programs/applications and O&M expenses are needed to keep them updated.

Analytics involves maintaining a "Data Lake" to house the voluminous amounts of data that will be coming in, Network model analysis software, and advanced analytics capabilities. Capital expenditures will be incurred in the first four years while O&M expenditures for the Data Lake occur in years 5-20.

Steady State Operations represents the costs of the Rhode Island Energy Business Operations team to operate the AMF systems in years 5-20 and are completely categorized as O&M expenditures. The Middleware software is not a direct 'AMF System' and encompasses several different Middleware software programs in use at PPL that will be needed to process and utilize the information coming in from the AMF meters. The costs included above represent the AMF specific coding and on-going maintenance for the Middleware itself.

The ADMS and OMS are systems that already exist in PPL's Pennsylvania service territory and will be adapted to serve Rhode Island Energy customers. Costs specific to both OMS and ADMS include integrating ADMS and OMS with the RF Headend and MDMS systems and the on-going maintenance costs (in years 5-20) of those systems. The costs that will be incurred are $2.96 million to implement integrations between AMF systems and ADMS and OMS systems.

Project Management involves both Rhode Island Energy personnel and outside vendors. All of the costs associated with Project Management will be capitalized and occur in the first four years of the program. As a result, there are no IT Project Management costs projected in years 5-20.

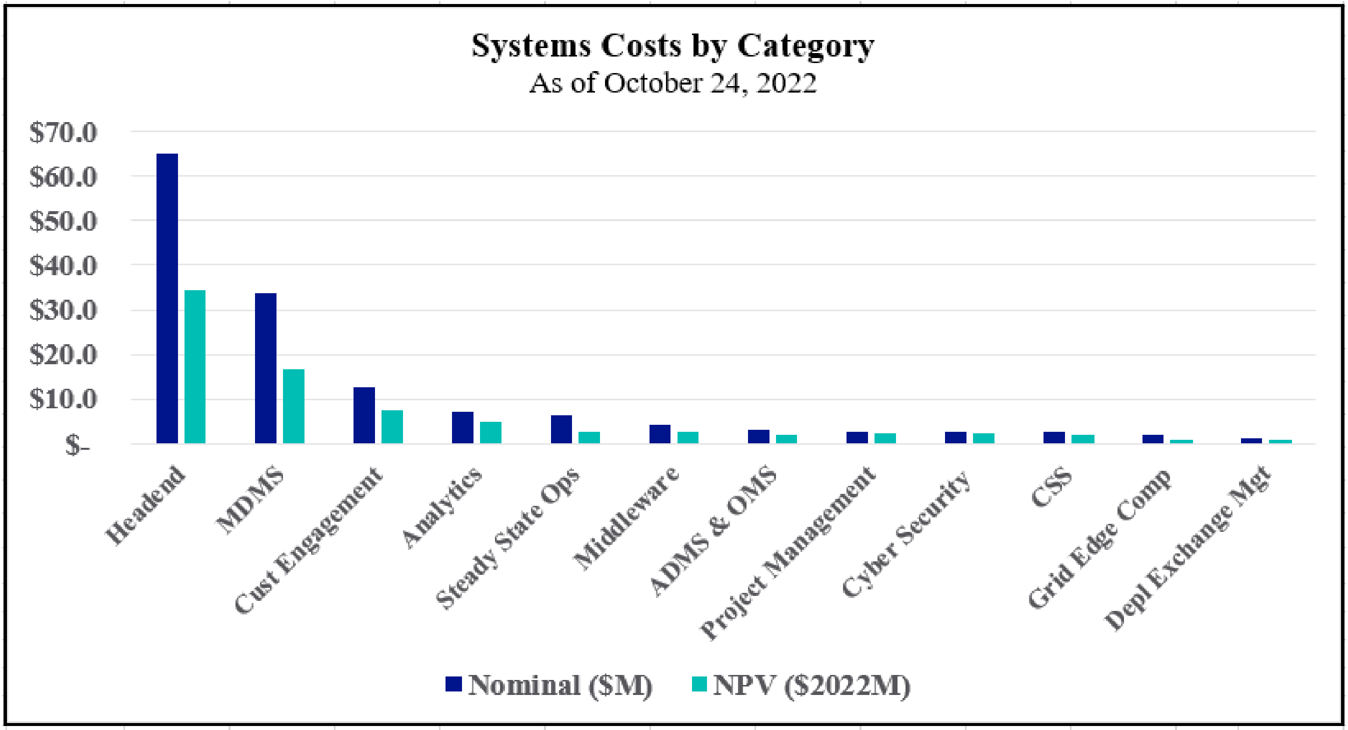
Cyber Security costs represent the cybersecurity penetration testing, access reviews, systems reviews, and further integration development specific to Rhode Island AMF implementation.

The Rhode Island Energy CSS will be a separate on-premises installation of the Pennsylvania CSS environment. AMF specific costs for CSS include the new AMF integrations and coding between CSS and MDMS and the on-going maintenance costs for the systems.

Grid Edge Computing includes load disaggregation software, and all costs are incurred in years 5-20 of the program. This represents a specific set of functionalities that is enabled by the AMF meters considered as part of this deployment. The costs were estimated this as a Rhode Island Energy SaaS offering from the Meter Vendor.

Figure 11.25 is a graphical representation of the System Costs by category.

Figure 11.25: Systems Costs by Category (Nominal $M and NPV $2022M)



11.7.3 AMF Electric Meter Costs

The costs of AMF electric meters include the hardware associated with the meters, the labor required for installing the meters, pre-sweeps, program management and meter base repairs. Pre-sweeps involve inspections of the meters prior to installation of new meters to ensure that the meter base is working, and the information related to the meter is correct. The National Grid Updated AMF Business Case did not include pre-sweeps in their deployment plan, but PPL's experience in Pennsylvania has found that performing the pre-sweeps significantly increases efficiency when actually deploying the meters. AMF electric meter costs are the largest single cost component, comprising $102.9 million nominal ($79.3 million NPV) of the $289.0 million nominal ($188.0 million NPV) costs, or approximately 36 percent. Figure 11.26 presents the Meter costs in table form and includes the split between Capex and OpEx on a nominal basis. Figures 11.27 presents the costs by category in graphical form.

Figure 11.26: Meter Costs by Category

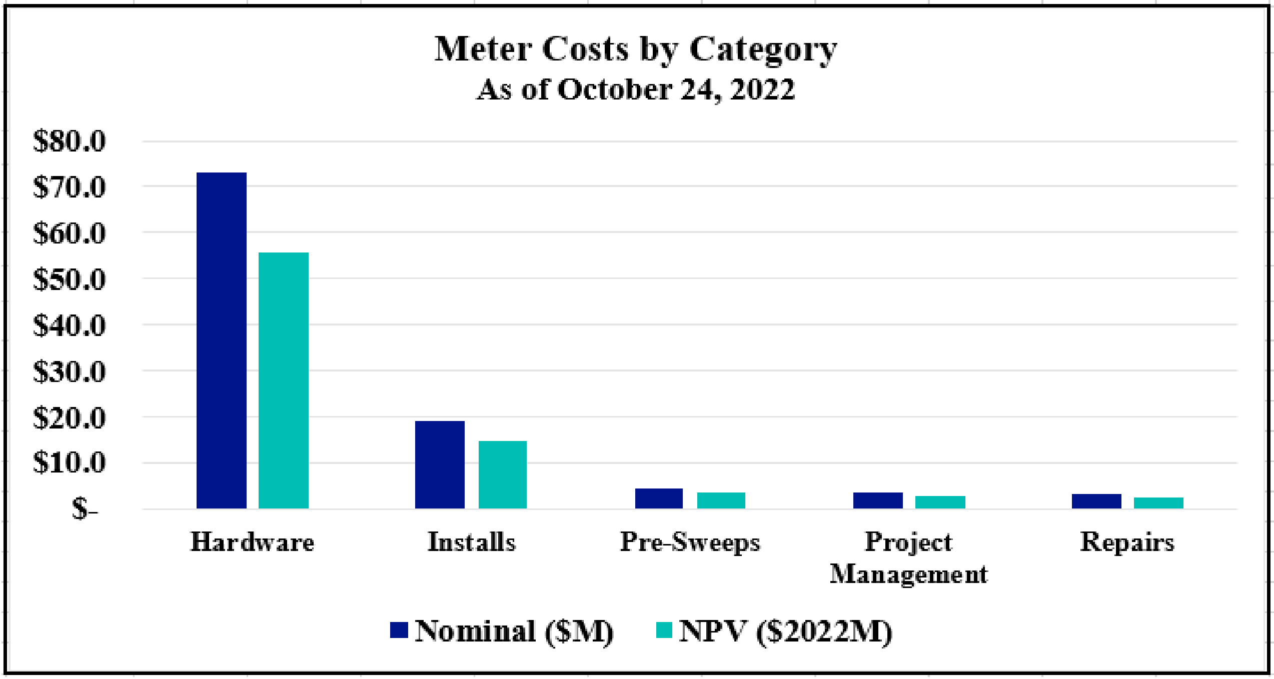
Meter Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($2022M)	CapEx	OpEx
Hardware	$ 73.01	$ 55.84	$ 72.85	$ 0.16
Installs	$ 19.03	$ 14.85	$ 19.03	$ -
Pre-Sweeps	$ 4.40	$ 3.52	$ 4.40	$ -
Project Management	$ 3.39	$ 2.73	$ 3.39	$ -
Repairs	$ 3.02	$ 2.35	$ -	$ 3.02
Total Meter Costs	$ 102.85	$ 79.29	$ 99.67	$ 3.18

Hardware costs for the meters total $73.0 million of the $102.9 million nominal of total meter costs with the majority of these costs incurred in years 1-4 during initial deployment. Some ongoing capital costs are anticipated for customer and meter growth over time plus a limited number of meter replacements due to premature equipment failure.

Meter install costs, which comprise $19.0 million of the $102.9 million nominal of total AMF electric meter cost, all are incurred in years 1-4 and are capitalized. These costs include both utility and vendor labor to physically install the meters and related equipment and facility costs to enable meter deployment.

Pre-sweeps represent approximately 4% of the total meter costs. Pre-sweeps are used to ensure a smooth deployment by first locating each meter and identifying issues (if repairs are needed or meter location is obstructed). Pre-sweeps proved to be very valuable during the PA AMF deployment in terms of efficiency and completeness of the actual AMF meter installations.

Figure 11.27: Meter Costs by Category (Nominal $M and NPV $2022M)



11.7.4 AMF Network Costs

The costs of implementing and maintaining the communications network include the network equipment costs, installation costs, plus internal labor costs for project management and ongoing operations. Network costs comprise $27.5 nominal million ($17.0 million NPV) of the $289.0 nominal million ($188.0 million NPV) costs of the AMF system, or a little less than 10 percent of the total costs. Figure 11.28 depicts the costs for the Network in table form and Figures 11.29 shows the costs in graphical form.

Figure 11.28: Network Costs by Category (Nominal $M and NPV $2022M)

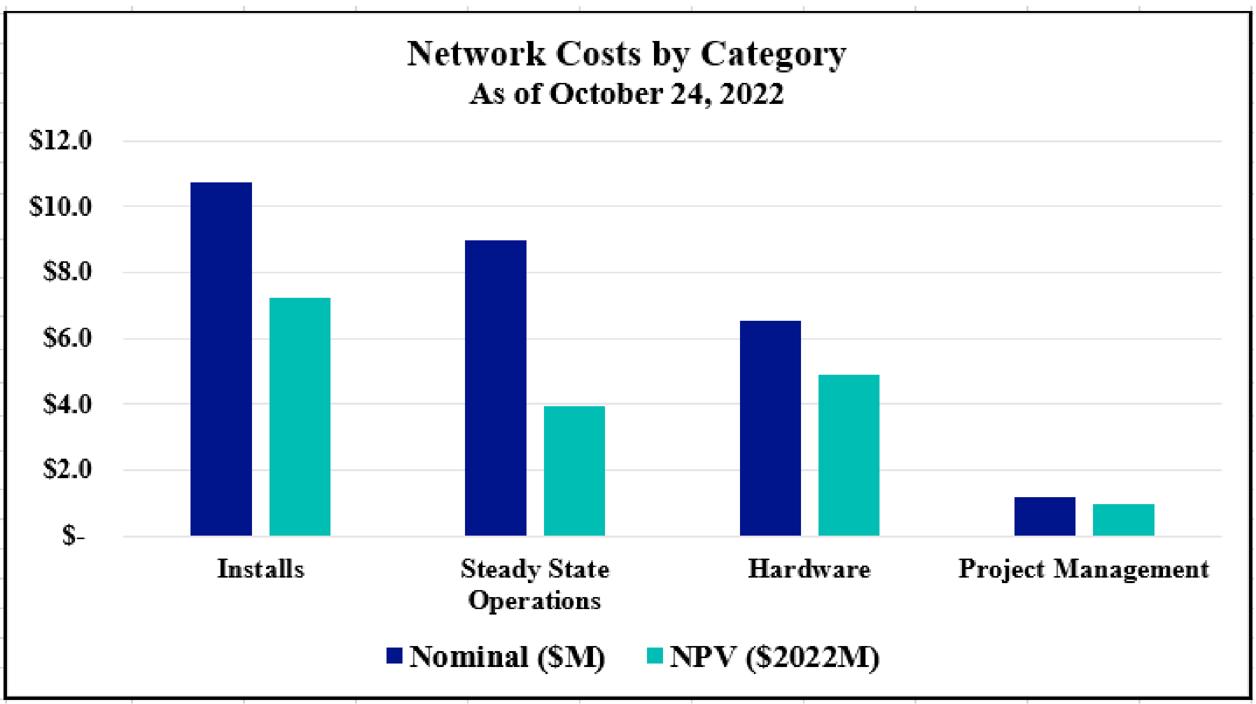
Network Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($2022M)	CapEx	OpEx
Installs	$ 10.76	$ 7.22	$ 7.18	$ 3.58
Steady State Operations	$ 8.97	$ 3.92	$ -	$ 8.97
Hardware	$ 6.57	$ 4.92	$ 6.57	$ -
Project Management	$ 1.19	$ 0.97	$ 1.19	$ -
Total Network Costs	$ 27.49	$ 17.03	$ 14.94	$ 12.55

The Hardware category includes the hardware for modems, gateways, cabinets, poles, and other infrastructure required to support the communications network. Hardware costs comprise $6.6 million of the $27.5 million nominal for the communications network equipment and installation costs, with the majority of these costs incurred in years 1-4, but some ongoing costs allocated to adapt to upgrades to advanced communications systems anticipated within the 20-year life of the AMF system.

The Installs category includes engineering and installation of routers, gateways, antennae, modems and other equipment on poles, in cabinets, and other locations. This also includes lab costs to test gateways, antennae, modems, and the functionality of the communications network to support AMF meters.

The Project Management category is the smallest of the four expenditures, totaling $1.2 million nominal. Steady State Operations includes internal labor and an RF Network Management Service Provider to support the communications system deployment and ongoing maintenance. Steady State Operations expenditures are significant at $9.0 million nominal; because they occur in years 5-20 of the program, their NPV is less than half of the nominal spend.

Figure 11.29: Network Costs by Category (Nominal $M and NPV $2022M)



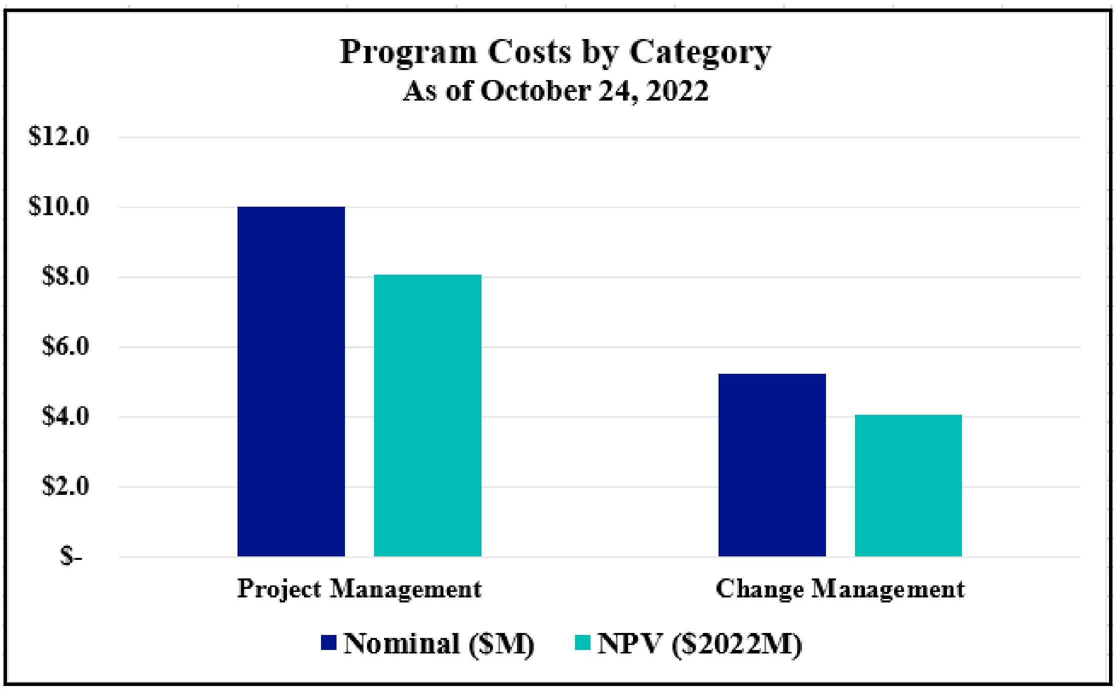
11.7.5 Program Costs

Program Costs include Project Management costs and Change Management costs to manage the development of the Systems needed to support the AMF program. The costs total $15.3 million NPV, approximately 5% of the total costs. The costs include internal labor, vendor costs, and material development costs. Figure 11.30 shows the Program Costs in table format and Figure 11.31 shows the same data in graphical form.

Figure 11.30: Program Costs by Category (Nominal $M and NPV $2022M)

Program Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($2022M)	CapEx	OpEx
Project Management	$ 10.03	$ 8.07	$ 10.03	$ -
Change Management	$ 5.24	$ 4.08	$ -	$ 5.24
Total Program Costs	$ 15.27	$ 12.14	$ 10.03	$ 5.24

Figure 11.31: Program Costs by Category (Nominal $M and NPV $2022M)



11.7.6 Cost Structure Assumptions

The assumed costs for AMF equipment, installation, and ongoing O&M are based on vendor unit prices, PPL experience in Pennsylvania and Kentucky, industry experience, benchmarking, and vendor contracts. Rhode Island Energy reviewed and determined the timing of each cost element.

11.8 Sensitivity Analysis

This business case leverages findings, results, and lessons learned from prior PPL deployments and from those of other utilities as well as advice and information from consultants and vendors. Any analysis would be incomplete without evaluating uncertainty.

Figure 11.32 lists and describes the different parameters (comprised of both cost and benefit factors) selected for the purposes of the sensitivity analysis Rhode Island Energy used to evaluate the uncertainty. The approach identifies the impact on the base case of independent changes of each of the seven variables addressed – meaning that with each sensitivity, only a single parameter is changed. Conducting the analysis in this manner helps identify the isolated impact on the business case because of a change in a single variable.

Figure 11.32: Summary of Sensitivities and Rationale

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
–Total Costs	NPV ($M): $188.0	10% Reduction (favorable) 10 % Increase (unfavorable)	Many of the costs included in the BCA (e.g., hardware) have been validated by pricing from AMF vendors and have little uncertainty. Other costs may have more uncertainty, e.g., labor costs, particularly in the long run. Rather than varying particular aspects of the cost, Rhode Island Energy calculated a +/-10% sensitivity on Total Costs.

Systems Costs	Projected Value	25% decrease (favorable) 25% increase (unfavorable)	IT costs have been projected in detail. However, due to the variety of interfaces involved, it is prudent to address some more significant uncertainty than was included in the Total Cost Sensitivity.
Faster Notification Benefits	22 minutes	20% increase (favorable) 20% decrease (unfavorable)	There is some uncertainty that this improvement will directly match PPL experience
Reduced Personnel Benefits	Projected Value	20% increase (favorable) 20% decrease (unfavorable)	Labor savings due to reduced truck rolls may have uncertainty due to the uncertainty in future inflation
Energy Insights	1.5%	20% increase (favorable) 20% decrease (unfavorable)	There is uncertainty that this improvement will directly match PPL and other utilities' experience
Energy Savings – VVO/CVR Based	0.5% Energy; 0.167% Peak	20% increase (favorable) 20% decrease (unfavorable)	There is uncertainty that this improvement will directly match PPL and other utilities' experience
CO2 Savings	$181.4 million NPV	20% increase (favorable) 20% decrease (unfavorable)	The value of CO2 savings is both significant to the analysis and uncertain.

11.8.1 Basic Sensitivity Analysis Results

Figures 11.33 and 11.34 represent the impact to the base BCA and BCA ratios of varying the overall costs of the project and varying the most significant of the benefits. For the costs of the program, Rhode Island Energy varied the total costs +/-10% for one sensitivity and varied the Systems costs (the largest and most variable of the costs) by +/-25%. The Company then combined the +/-25% of the Systems costs with +/-10% of the remaining costs to develop a combined sensitivity. As can be seen in Figure 11.33 below, the BCA ratio for the unfavorable cost sensitivities are 3.5 for the individual sensitivities and 3.3 when you combine the unfavorable sensitivities, compared to a base BCA ratio of 3.9. The favorable sensitivities yield a 4.3 BCA ratio for the individual sensitivities and a 4.6 for the combined sensitivities.

Figure 11.33: Cost Sensitivity Results: Total Costs & System Costs

Cost Sensitivities					
As of November 12, 2022					
	Base NPV ($2022M)	Unfavorable +10% & +25%		Favorable -10% & -25%	
		NPV ($M)	B/C Ratio	NPV ($M)	B/C Ratio
Total Base Benefits	$ 729.2				
Total Base Costs	$ 188.0				
Total Costs: +/-10%	$ 188.0	$ 206.8	3.5	$ 169.2	4.3
Systems Costs: +/-25%	$ 79.5	$ 99.4	3.5	$ 59.6	4.3
Combination: Total Costs and Systems Costs		$ 218.7	3.3	$ 157.3	4.6

To perform a sensitivity on the benefits, Rhode Island Energy varied a combination of benefits that were significant and benefits that were uncertain. The benefits were each varied by +/-20% individually on an NPV basis and the resulting BCA ratios are shown in Figure 11.34 below. The -20% sensitivities resulted in a range of BCA ratios from 3.7 to 3.8. If all the unfavorable sensitivities are combined, the BCA ratio declines to 3.2. The favorable sensitivities (+20%) had BCA ratios of 3.9 to 4.1. If all the favorable sensitivities are combined, the BCA ratio increases to 4.5.

The base values for the selected benefits total $597.9 million NPV which is 82% of the total benefits. Even reducing this significant percentage of the benefits by 20% still results in an excellent BCA ratio of 3.2.

Figure 11.34: Benefit Sensitivity Results

Benefits Sensitivities					
As of November 12, 2022					
Benefit	Base NPV ($M)	NPV ($M)	B/C Ratio	NPV ($M)	B/C Ratio
		Unfavorable: -20%		Favorable: +20%	
Faster Outage Notification	$ 169.2	$ 135.4	3.7	$ 203.0	4.1
Reduced Personnel	$ 39.5	$ 31.6	3.8	$ 47.3	3.9
Energy Insights Savings	$ 110.7	$ 88.6	3.8	$ 132.9	4.0
VVO/CVR Benefits (Energy Only)	$ 120.5	$ 96.4	3.8	$ 144.6	4.0
Non-Embedded CO2 Benefits	$ 158.0	$ 126.4	3.7	$ 189.6	4.0
Total Savings for Sensitivity Benefits	$ 597.9	$ 478.3	3.2	$ 717.4	4.5

The Company also combined all the unfavorable costs and benefits sensitivities and all the favorable costs and benefits sensitivities to test a “worse case” scenario; the result if all the costs go up and the majority of the benefits go down. Figure 11.35 shows the results of this sensitivity combination. As can be seen the Unfavorable BCA ratio is 2.8 and the Favorable BCA ratio is 5.4.

Figure 11.35: Benefits and Costs Sensitivities Combined

Combined Sensitivities		
As of November 12, 2022		
	NPV ($M)	NPV ($M)
	Unfavorable	Favorable
Total Benefits w/Sensitivities	$ 609.61	$ 848.76
Total Costs w/Sensitivities	$ 218.71	$ 157.25
Combined Sensitivities: B/C Ratio	2.8	5.4

11.8.2 Specific Issue Sensitivities

In addition to these basic sensitivity results, Rhode Island Energy performed additional sensitivities to address specific issues. These issues involve:

1. Those benefits that need the Grid Modernization Program to be realized,

2. Benefits associated with the change from AESC 18 avoided cost values to AESC 2021 avoided cost values,

3. Benefits associated with Energy Insights, and

4. Benefits associated with TVR.

The TVR sensitivities are extensive and are discussed in Section 13. The GMP, AESC, and Energy Insights sensitivities are addressed below.

The first of these issues involves what would happen if the PUC approved the AMF filing but did not subsequently approve the GMP. There are two benefits included in the AMF BCA that depend on the GMP; the VVO/CVR benefit and the Avoided DSP Sensors benefit. Figure 11.36 shows the BCA results for AMF without VVO/CVR or the DSP sensors included. As can be seen, the AMF BCA ratios remain significantly above 1.0, at 3.0 values and 3.1 for $2022 NPV.

Figure 11.36: Benefits without GMP Benefits

RIE Benefits Included in BCA Sorted by Program Category		
As of November 12, 2022	Nominal ($M)	NPV ($2022 M)
Direct Customer Benefits	**$ 314.5**	**$ 213.2**
VVO/CVR Benefit	**$ 168.9**	**$ 126.1**
Energy Insights Savings	**$ 147.6**	**$ 110.7**
Whole House TOU/CPP - Opt-In (20%)	**$ 115.1**	**$ 84.1**
EV/TVR Benefit - Opt-In (20%)	**$ 112.4**	**$ 79.5**
Avoided AMR Costs	**$ 89.5**	**$ 61.7**
Remote Metering Benefits	**$ 56.1**	**$ 25.1**
Avoided DSP Sensors	**$ 23.2**	**$ 14.4**
Reduced Field Investigations	**$ 17.2**	**$ 7.7**
AMF Meter Reading Benefits	**$ 14.8**	**$ 6.7**
Total RIE Benefits included in B/C Ratios	**$ 1,059.3**	**$ 729.2**
Total RIE Benefits Less VVO/CVR and Avoided DSP Sensors	**$ 867.2**	**$ 588.7**
AMF Costs	**$ 289.0**	**$ 188.0**
B/C Ratio w/o VVO/CVR and Avoided DSP Sensors	**3.0**	**3.1**

Second, the calculation of benefits changes from using the AESC 2021 report rather than the AESC 2018 report to estimate avoided costs. This sensitivity is much more complicated, involving numerous benefits associated with different benefit programs. These benefits include avoided energy costs, capacity costs, monetized CO2, transmission and distribution costs, non-embedded CO2, and non-embedded NOx. Rhode Island Energy estimated this sensitivity by summing each of these benefits across the benefit programs and reducing/increasing them based on the percentage changes shown in Table ES-4 from the AESC 2021 report.[58] Although these percentages are shown for summer peak, Rhode Island Energy used them to calculate differences in the total value of the benefits. Figure 11.37 shows the results of this calculation and, as shown in the figure, the benefit value changes offset each other and there is very little change in the nominal or the NPV benefits. As can be seen in the figure, the nominal BCA ratio remains the same whether AESC 2018 values are used or AESC 2021 values are used.

Figure 11.37: AESC 2021/AESC 2018 Sensitivity

AESC Sensitivity: 2021 v. 2018		
As of November 3, 2022	$ Nominal (M)	$2022 NPV (M)
Total Benefits Using AESC 2021	**$ 1,059.3**	**$ 729.2**
Total Benefits Using AESC 2018	**$ 1,079.4**	**$ 740.9**
Total Costs	**$ 289.0**	**$ 188.0**
B/C Ratio Using AESC 2021	**3.7**	**3.9**
B/C Ratio Using AESC 2018	**3.7**	**3.9**

Third, Rhode Island Energy analyzed the impact of varying participation rates for the calculation of benefits from Energy Insights. There are two benefits that use participation rates: (i) the Energy Savings from Energy Insights, and (ii) the Customer Bill Savings from Energy Insights. Table 11.38 shows the results of changing the participation rate. As can be seen, the BCA ratios remain high, ranging from 3.4 to 4.1 for the nominal BCA ratios and 3.6 to 4.1 for the NPV BCA ratios.

58 Synapse Energy Economics, Inc. et al, *Avoided Energy Supply Components in New England: 2021 Report*, Prepared for AESC 2021 Study Group (March 15, 2021) at p.8.

Figure 11.38: Energy Insights Percent Participation Sensitivities

Energy Insights Sensitivities - Percent Participation						
As of November 12, 2022						
	Energy Savings Benefit		Customer Bill Savings Benefit		Combined Energy & Bill Savings	
Participation %	$ Nominal (M)	$2022 NPV (M)	$ Nominal (M)	$2022 NPV (M)	Nominal B/C Ratio	NPV B/C Ratio
Base Scenario						
10%	$ 10.37	$ 7.81	$ 23.58	$ 14.67	3.4	3.6
20%	$ 20.74	$ 15.62	$ 47.15	$ 29.35	3.5	3.8
30%	$ 31.10	$ 23.42	$ 70.73	$ 44.02	3.7	3.9
40%	$ 41.47	$ 31.23	$ 94.30	$ 58.70	3.8	4.0
50%	$ 51.84	$ 39.04	$ 117.88	$ 73.37	3.9	4.1
60%	$ 62.21	$ 46.85	$ 141.45	$ 88.04	4.0	4.0
70%	$ 72.58	$ 54.65	$ 165.03	$ 102.72	4.1	4.1

11.8.3 Sensitivity Summary

Rhode Island Energy conducted numerous sensitivity analyses both from a basic perspective and from a specific issue perspective. In all cases, the BCA ratios for the AMF project remain very strong.

Section 12

SECTION 12: COST RECOVERY AND REVENUE REQUIREMENTS

This section describes the cost recovery proposal for the revenue requirements for the AMF solution and the allocation of costs among rate classifications, methodology for addressing Opt-Out costs, and a proposal to allocate AMF among rate classifications. This section directly addresses the following ASA items: "Revenue Requirement for AMF deployment", "A proposal to allocate AMF costs among rate classifications", and "Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF".

The Company is proposing to recover the incremental costs associated with the AMF investments through a separate factor outside of base distribution rates ("AMF Factor") that seeks to recover from customers the actual capital placed in service and O&M incurred. The Company will update the AMF factor semi-annually and based on historical, actual data from the prior six-month period. The Company's cost-recovery proposal and associated revenue requirements are presented in detail in the pre-filed joint direct testimony of Company witnesses Stephanie A. Briggs and Bethany L. Johnson, together with their associated schedules. A summary of this proposal is provided below.

Article II, Section C.16(c) of the ASA permits, but does not require, Rhode Island Energy to reopen base distribution rates to recover the incremental revenue requirements associated with costs to implement AMF. Specifically, this provision provides:

> To the extent it is determined by the PUC that deployment of AMF should move forward, and the Company must incur costs during the MRP to begin the deployment process, the MRP ***may be re-opened to propose the revenue requirement for any such approved initiatives during the term of the MRP in base distribution rates, as approved by the PUC***. (Emphasis added.)

At the time of the ASA, the parties anticipated that the Company would file a base distribution rate case in the Fall of 2021; therefore, the "Reopener" provision contemplated the possibility of approximately one-year of AMF costs before the new base distribution rate case. As part of the Acquisition, PPL committed that the Company would not file a base distribution rate case for at least three years from the date of the transaction close, which was in May 2022. In light of the extended period of the stay-out period and the magnitude of the costs for the AMF project, the Company determined a separate factor is in the best interest of customers because a factor outside of base distribution rates seeks recovery for only those costs that are actually incurred in the prior six-month period. In contrast, pursuant to the Reopener, the Company would need to include approximately three years (or through the end of the stay-out period) of estimated AMF capital and O&M costs for recovery in base distribution rates beginning upon approval of the AMF Business Case. By recovering costs for AMF investments through a separate AMF Factor during the stay-out period, customers would benefit because the AMF Factor for the applicable six-month period includes only those costs that the Company has incurred at the time the AMF Factor takes effect and uses the most recent kWh forecast (with any over- or under-recovery from the prior six-month period due to differences in kWh forecasted versus actual kWh sales reconciled in the subsequent AMF Factor). If the Company used a forecasted method to establish the AMF Factor, such as with the Reopener, customers could be paying for costs upfront that the Company might not incur for several years, which are subject to change because of differences in capital versus O&M work performed or project delays.

A separate cost-recovery mechanism benefits the Company as well because it allows the Company to receive timely recovery of actual costs incurred and would align cost recovery with actual spend on a significant investment, such as the AMF project.

As further discussed in Ms. Briggs' and Ms. Johnson's joint testimony, the Company will include in its calculation of revenue requirements the eligible plant additions and operating costs that have not previously been reflected in the Company's rates or rate base. In addition, as Ms. Briggs and Ms. Johnson explain in their joint testimony, there is approximately $1.2 million of AMF cost recovery currently included in base distribution rates and this amount will be reduced from the AMF Factor revenue requirement to avoid double recovery of these costs.

Also, the Company proposes to reduce the operating costs in the annual revenue requirement by 80 percent of the Non-Outage Management System avoided O&M Costs (the benefits from O&M savings not related to outage management such as reduced AMF operational costs, remote meter capabilities, and mitigation and/or reduction of damage claims). O&M expense benefits that exceed the 80 percent reflected in the revenue requirement would be retained by the Company until the next base distribution rate case when new base rates are set; providing an incentive for the Company to maximize benefit realization for customers. For customers, the value of this approach is guaranteed cost savings, realized sooner than would otherwise occur. Traditionally, such operational savings would not be reflected until new base distribution rates are set in a future base distribution rate case; therefore, customers would not realize such benefits until the effective date of the rate plan following AMF network deployment.

As described in more detail in Ms. Briggs' and Ms. Johnson's joint testimony and schedules, the proposed AMF Factor would be a per-kWh volumetric charge for all rate classes who receive electric distribution service from the Company. The Company would apply the distribution revenue allocators approved in the Company's compliance filing in Docket No. 4770 to allocate the incremental AMF revenue requirements among the rate classes.

Section 13

SECTION 13: TIME VARYING RATES AND RATE DESIGN

This section discusses Rhode Island Energy's plan to utilize AMF to create TVR in the future and how AMF with TVR can enable new pricing and allocation mechanisms. TVR coupled with DG tariffs can better compensate DERs for their value.

OVERVIEW

One of the major benefits that AMF offers Rhode Island Energy and the energy system at large, and ultimately and most importantly Rhode Island Energy's customers, is the ability to offer Time Varying Rates (TVR). TVR is where the price changes over time and is applied to volumetric or demand-based billing elements and can be used to incentivize behavior by better reflecting the actual cost of both supply and delivery service. One way to reduce spikes in demand and better manage system challenges is with rates that vary by time of use in a way that engages customers to make behavior changes that become a meaningful part of the solution. For example, by pricing electricity higher at times when demand peaks, consumers both large and small, have an incentive to reduce electricity use when it matters the most. TVR is important to Rhode Island customers because it presents an opportunity to save costs and it is important to Rhode Island Energy because it presents an opportunity to expand solutions that can defer building infrastructure that would otherwise be needed during peaking conditions and can further optimize existing asset utilization.

AMR lacks necessary functionality to offer TVR. AMR meters provide usage information one time per month for the sole purpose of billing which is a significant barrier for implementing TVR rates. With AMR, consumption usage is known at the time of monthly billing which is well after the system peak event making it impossible to implement TVR with present-day AMR capabilities. With AMR, customers currently have no visibility of their usage in real time, the meters are not capable of measuring or communicating interval data and there is no mechanism in place to communicate variable pricing. As a result, customers have no timely information from which to base a usage decisions and Rhode Island Energy has no mechanism to communicate variable rates in near-real time. As the system becomes increasingly complex, the times that the generation, transmission and distribution conditions are challenged will likely not be aligned; existing and new markets will likely evolve and be created accordingly to provide new value propositions. AMF provides a platform for TVR rate design. With AMF, customers' demand and interval energy usage will be visible and presented in a way that customers can easily understand their load profile and make choices that reflect rate incentives in near-real time. AMF provides a platform that will enable the Company to overlay rate design parameters that vary by time, which could be by season, month, day, hour or every few minutes; are consistent with rate designs and design principles that are described in Docket 4600; and aligned to likely assumptions in a future TVR rate filing. With TVR, the timing of charges can be matched to customers' usage which will provide customers with an opportunity to better manage their bills and help reduce energy burden. TVR, enabled by AMF will provide customer the ability to internalize the cost impact of how they use electricity, understand impact of changing their behavior to adjust usage patterns, improve system utilization, and save money. The most cost-effective and secure means to achieve the described TVR functionality is by utilizing the AMF. TVR is just one usage of many for AMF. With multiple value streams, it makes TVR from AMF a superior economical solution.

TVR may be applied to volumetric or demand-based billing elements. This section focuses on the considerations related to using TVR designs for residential customers and satisfies the ASA requirement to include "Assumptions upon which a proposal to develop time varying rates will be based."

Economic theory suggests that in efficient markets, prices for goods are equal to their marginal cost. The Docket 4600 principles endorse this notion. Principle 2 calls for rates that promote "economic efficiency over the short and long term"; Principle 3 calls for rates that provide "efficient price signals that reflect long run marginal cost" and Principle 12 discusses "appropriate investments" – which also suggests marginal cost pricing. However, current utility pricing practices do not approximate marginal cost pricing for either supply or delivery. Using the capabilities from AMF, to implement some form of TVR can offer the electricity sector the ability to fix this mismatch.

In the region, including Rhode Island, the presence of the organized market for bulk energy services means that customers receive some services for which there is a functioning market and some for which there is not. In the former case, where there is a market for generation and related attributes, and prices reflect marginal costs hour-by-hour and location-by-location, an efficient market is in effect. In the latter case where markets are incomplete, such as for network costs, other tools and studies can help produce improvements that approximate marginal costs.

For AMF and rates to fulfill the possibility of a lower cost system, the marginal costs that customers see through rates should be aligned with marginal system costs. In complementary fashion, all externalities would be internalized, although such complete pricing is rare in practice. Efficient rates should differentiate between fixed and marginal costs. The distinction is a matter of timing. Fixed costs are investments that have already been undertaken or approved or for in-flight projects and activities with set budgets. Marginal costs are costs to provide the next unit of service, and, by definition, are incurred in the future. Marginal costs are driven by customer behavior, such as the decisions about when and how much energy to consume. Under efficient rate design, customers who lower their costs also lower marginal system costs and in turn deliver lower total system costs. However, there are many costs, notably those in the network or generation capacity, that have already been incurred to build the existing system and thus cannot be reduced by changes in customer behavior. Rates are necessary to recover those costs in an equitable manner. However, when rates are set such that some customers can avoid paying their share of those fixed costs, they necessarily transfer those to other customers who pay more to make up the difference without lowering total system costs.

There are many ways to allocate the costs of electric supply. In this TVR analysis, the Company has organized these rates along a spectrum. The spectrum, moving left to right, moves from completely time invariant, to increasingly dynamic and cost-reflective, with the highest efficiency and greatest potential for customer savings aligned with system cost. The spectrum supports the AMF filing because it demonstrates that AMF offers important benefits to customers through different TVR designs. Under present conditions, many of the benefits develop from lowering costs associated with peak load. In the future, as clean variable generation will likely compose a larger share of the generation mix, that will in turn prompt changes to the volatility and patterns of energy prices. TVR will need to be flexible to adapt to such changes as they manifest in energy markets.

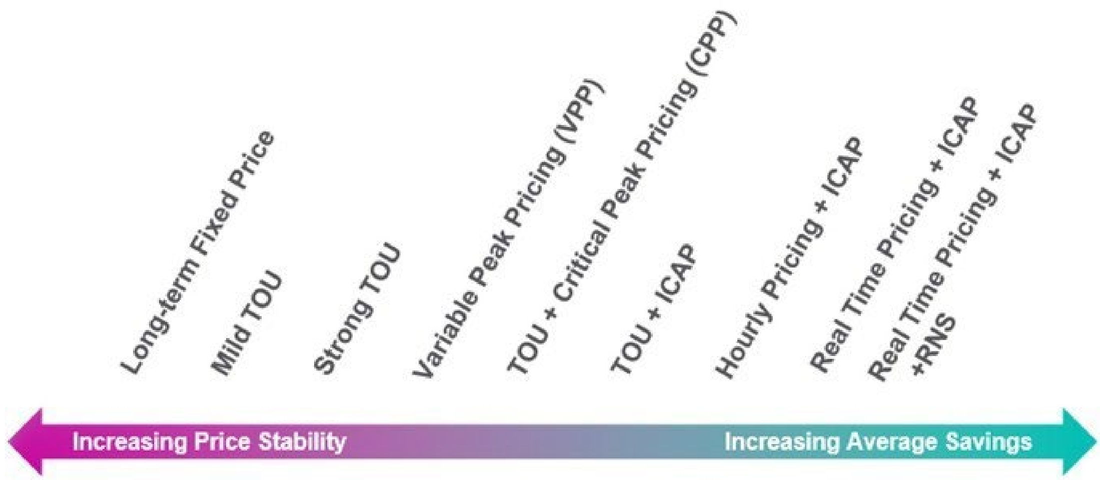
Placing rates along a spectrum from least to most cost-reflective facilitates comparisons among TVR designs and makes the tradeoffs among them explicit. For example, University of California Berkeley economist, Severin Borenstein[59] (2012) describes rate designs along a spectrum. Under the current construct, the vast majority of residential customers saw prices for electricity that did not vary within a billing period, but Borenstein noted that at the "opposite end of the spectrum would be a real-time pricing structure in which the price varies hour to hour (or even more frequently) reflecting changes in the wholesale price of electricity."[60]

In Figure 13.1, the Company presents a range of options, all of which have been deployed in some form, for consideration for future TVR. In Figure 13.1, "ICAP" refers to "installed capacity" rates which properly align retail rates with the ISO-NE Forward Capacity Market and "RNS" refers to Regional Network Service, for transmission. Figure 13.1 is not exhaustive but any other potential rate designs could be mapped along the same spectrum.

[59] Borenstein, Severin, *Effective and Equitable Adoption of Opt-In Residential Dynamic Electricity Pricing*, Working Paper Series: Working Paper 18037 (2012).

[60] Borenstein, Severin, *Effective and Equitable Adoption of Opt-In Residential Dynamic Electricity Pricing*, Working Paper Series: Working Paper 18037 (2012).

Figure 13.1: Supply Rate Design Spectrum



Long-term Fixed Price

Rhode Island Energy's s residential and smaller business customers today have a long-term fixed rate as their price per-kWh, which does not vary over a six-month pricing period. Other jurisdictions have fixed prices that vary in length.

Fixed rates perform well against half of Principle 8 from Docket 4600 that states rates should be "understandable to all customers, "because they are simple for customers to understand. However, fixed rates do not satisfy the other half of Principle 8, transparency, because they combine all of the costs of supply, including energy, capacity, transmission, and the per-kWh cost of the state's Renewable Energy Standard, into one price. Similarly, flat prices do not meet the objectives of Principle 2: "promote economic efficiency over the short and long term." Nor do fixed rates enable "consumers to manage their costs" (Principle 5) or provide "opportunities to reduce energy burden" (Principle 10) because they maintain a complicated set of cross subsidizations between customers.

Mild TOU

Instituting Mild time-of-use ("TOU") periods begins the process of transmitting some of the temporal variation in wholesale energy market costs to retail customers but does so in a muted fashion. One might also describe this as a "Simple TOU." The Mild TOU would not differentiate between the multiple wholesale products and the important temporal differentiationamong them. Nor would a mild TOU vary by season. Rather, customers would see the same on-peak period for all months of the year.

A Mild TOU period might cover a wide on-peak period of 7 am to 11 pm. Alternatively, recognizing that increased solar generation may reduce daytime power prices, a more modernon-peak period might cover the hours of 4 pm to 9 pm.

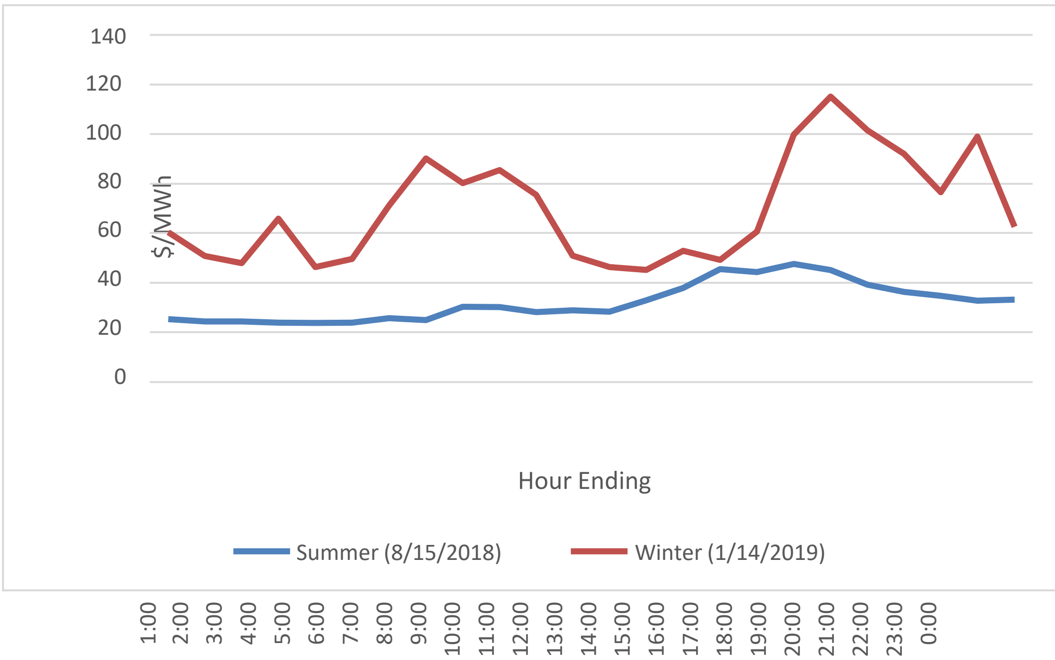
A Mild TOU likely has relatively little variation between the peak and off-peak prices, withpeak-to-off peak ratios no more than 1.5. As with current time invariant rates, Mild TOU periods do not perform well against the Docket 4600 Principles 2 and 3 that value economic efficiency. As the smallest change from today's flatrates, Mild TOU aligns with Principle 9 which emphasizes gradualism.

Strong TOU

A Strong TOU improves on the Mild TOU by increasing the fidelity of the market prices to customers. Strong TOU may divide up the day into multiple segments such as a high, medium, and low period and may also vary by season. For example, it might recognize that in New England, prices are highest during winter in the early mornings and in the evenings, and moderate in the midday. By contrast, in the summer, prices rise over the course of the day, and peak as the sun goes down and solar generation drops, but the morning peak is absent. These varying daily or seasonal factors can be taken into account when creating a Strong TOU.

Typical days by season are illustrated in Figure 13.2.

Figure 13.2: Energy Prices on Typical Summer and Winter Days



Source: ISO-NE

As compared to a Mild TOU, a Strong TOU likely has higher variation between the peak andoff-peak price, with ratios of the highest peak periods to the lowest periods of at least two. Both types of TOU rely on setting the periods *and* prices ahead of the billing period.

In terms of performance against Docket 4600 principles, a Strong TOU is similar to a Mild TOU. It performs well in terms of gradualism while improving incrementally upon a Mild TOU along principles related to economic efficiency. Neither Strong TOU nor Mild TOU would perform well on Principle 12 to “encourage or discourage appropriate investments that enable the evolution of the future energy system.”

Peak Time Rewards

Peak Time Rewards (“PTR”) are a form of demand response in which the customers’ energy providermakes a payment to customers for reducing their usage during designated peak times. As with other demand response products, customers earn payments, bill credits or rewards, based on thechange in their usage from an established baseline. The peak events may be based on energy orcapacity. Events are usually called on a day-ahead basis.

PTR is distinct from other rate designs presented in this section because it includes a payment from the energy provider to customers rather than payments from the customer to their energy provider. As with other demand response products, PTR make up for otherwise incomplete pricing mechanisms. PTR may be combined with other pricing mechanisms in Figure 13.1. If customers saw more complete pricing mechanisms that corresponded with the cost of their actions, they could internalize the actions that are otherwise incorporated in demand response actions.

PTR performs poorly across the Docket 4600 principles related to efficiency (Principles 2, 3, 7, and 12). PTR does better in gradualism (Principle 9) because customers have the option not to participate and takes an initial step towards empowering consumers to manage their costs.

Variable Peak Pricing ("VPP")

Variable Peak Pricing describes a broad class of rate designs in which the on-peak price varies. Classically, under Mild or Strong TOU rates, the price in the on-peak period is fixed. Generally, like TOU, VPP fixes the on-peak hours.

VPP has been implemented in different regions, including by Eversource in Connecticut and Oklahoma Gas and Electric ("OG&E") in Oklahoma. Eversource has a peak period from noon to 8pm daily. The price of the on-peak period varies daily.[61] Similarly, OG&E runs a VPP program for the hours of 2 pm to 7 pm on non-holiday weekdays during the summer season of June through October. OG&E also runs a Critical Peak Pricing ("CPP") structure of up to 80 hours as anoverride on their VPP program for residential customers.[62] OG&E notifies customers of the prices by their chosen method (email, text or phone) on a day-ahead basis.

Figure 13.3: VPP Illustration

[61] Eversource, Variable Peak Pricing History, https://www.eversource.com/clp/vpp/vpphistory.aspx.

[62] OG&E, Standard Pricing Schedule: R-VPP; Residential Variable Peak Pricing, https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA.

VPP is a flexible tool. VPP events may be used to capture variations in energy prices or capacity costs. Generally, VPP has not differentiated between which underlying market products are responsible for the peaks which are transmitted to end use customers. In some cases, VPP are used to capture variations in energy prices and some of the costs of generation capacity. VPP may be overlaid over flat rates or TOU structures. For example, in Figure 13.3, the teal bars representing the off-peak period rise slightly in Days 5-7 to illustrate a higher off-peak energy price than in Days 1-4. This shows a VPP overlaid on a TOU rate.

VPP offers improvements from the status quo for principles related to efficiency, however, the variable nature of the peak price may be challenged by Docket 4600 Principle 8 that rates be "transparent and understandable to all customers."

Critical Peak Pricing ("CPP")

CPP allows the utility or entity which is pricing supply the ability to dynamically respond to changing pricing patterns by creating critical peak periods, or events. All CPP events have the same prices across a pricing period. CPP is distinct from VPP because the prices charged during VPP events may vary event to event, while, in a CPP, the prices are the same for all events. CPP may be overlaid over flat rates or TOU structures. On the spectrum in Figure 13.1, CPP is combined with a TOU structure, as is most common.

Both CPP and VPP are flexible tools that can capture variations in energy prices or capacity costs, although CPP is most commonly used for generation capacity costs. As used henceforth, CPP will refer to a rate design that captures capacity costs.

CPP represents an important step forward from TOU periods or VPP because it can separate out the costs of capacity, a distinct market product, into separate events. The utility or energy provider can initiate CPP events to communicate the possibility of setting a capacity hour. CPP events spread capacity costs, which are determined in a single hour of the year, over multiple events. CPP thus balances a strong signal with a customer-friendly smoothing. Also, where the capacity hour is set based on the annual ISO-NE peak hour retrospectively, CPP offers customers advanced notification for events. Unlike TOU periods, the timing of CPP events may vary. For example, Monday may not be a CPP day, but if Tuesday has a chance to set the ISO- NE peak hour, the utility could call a CPP event. Thus, communicating that CPP events are occurring is an important element of their success. CPP events can be communicated to customers in multiple ways, depending on customer preference. Options include posting CPP events online, or more active methods such as alerts to customers via email, text, smart phone application or phone consistent with customer preferences. Finally, CPP may support automatedresponses by certain programmable devices which could help customers manage their energy bills.

By separating out high-priced hours for energy or capacity, relative to flat rates, consumers who manage their energy usage in those hours have a powerful tool to manage their costs, consistent with Principle 5. CPP events also perform well against Principle 3 regarding efficient price signals and, with notifications, attempt to meet Principle 8 regarding transparency to customers. However, by spreading capacity costs across more hours than those in which they are incurred, CPP mutes the precise way in which capacity costs are allocated, and some consumers may want the ability provided through more granular designs to further manage their costs.

ICAP/RNS

As used in Figure 13.1, ICAP refers to the practice, common among larger customers, of charging customers with the costs associated with capacity based on their actual usage in the annual peak hour. In a simplified analysis, ISO-NE calculates a market participant's capacity cost based on their contribution to their capacity zone's load in the peak period. The market participant may bea load-serving entity ("LSE") or large customer participating in the market directly. In the case of an LSE, it then allocates the capacity costs charged to it by ISO-NE across its own customers. Acharge, abbreviated here as ICAP, based on a retail customer's demand in the annual peak hour on which those capacity costs are calculated is most aligned with cost causation. Using an ICAPcharge for capacity is incomplete because it does not account for the time-variant nature of energy. The spectrum in Figure 13.1 first presents ICAP paired with TOU periods for energy, and then with more accurate Hourly Pricing moving further right.

In slight contrast to capacity obligations which are set annually, ISO-NE allocates transmission costs for Regional Network Service ("RNS") based on demand in the monthly peak hour. The distribution company, functioning as the LSE, presently merges ISO-NE transmission costs with other local transmission costs and then allocates those charges to each customer class based on its contribution to peak load. However, an unbundled rate for ISO-NE costs allocated based on peak load to the distribution company's customers is, like ICAP, a second example where a demand charge more precisely captures the responsibility for cost causation rather than rolling those charges into volumetric rates. Since both the costs for capacity and those for RNS (transmission) are incurred in a single hour, rates that spread them into a greater number of hours will result in a quantifiable loss of efficiency where prices are too low on-peak, and too high off-peak, leading consumers to consume more than is economically efficient on-peak.

Under an efficient rate, customers would pay for their generation capacity based on their consumption in the ISO's peak load hour. Similarly, the customer would pay for transmission charges based on their load in the monthly peak hour. Such efficient charges offer significant opportunities for savings and managing energy costs. However, when the hours are known only after the event, this may prove complicated for residential customers as a default rate. While AMF enables such efficient rates, for residential and small commercial customers, rate design must balance the constant tradeoff between efficiency gains and costs of implementation and challenges of increased complexity.

Demand charges for ICAP and RNS that match costs accrued based on peak hours perform well on efficiency grounds. By matching the timing of charges to customers to the underlying market elements which drive those costs, customers also have ample opportunity to manage their bills (Principle 5) and such measures can help reduce energy burden (Principle 10). ICAP and RNS charges can be well understood and transparent when enabled by AMF and customers are provided visibility into real-time information about their demand (Principle 8). However, such focused hourly charges will be novel for residential classes (Principle 9).

Hourly Pricing/Real Time Pricing ("RTP")

Hourly Pricing and Real Time Pricing describe plans where the clearing prices for energy in the ISO-NE markets are transmitted directly to customers. ISO-NE runs a multi-stage market where generators and suppliers submit day ahead bids, which resolve into hourly bids. These hourly prices for energy could become the rate that end customers pay. Using the hourly price would capture far more of the variation in energy prices on both an intra- and inter-day basis than even a well-designed TOU rate which must anticipate the behavior of the markets.

Where the output of the day ahead market is an hourly price, the "real time market" resolves at five-minute increments. In theory, energy providers could provide a plan to charge customers the real time clearing prices. In the case of the plan where customers pay day-ahead market prices, because there is usually a difference between the day ahead and real time prices, there would need to be a small true-up mechanism to account for those differences.[63]

RTP is maximally efficient with respect to energy prices and thus fulfills Docket 4600 principles two and three. By varying prices precisely, RTP allows consumers the choice to manage their costs as they see fit (Principle 5) and communicates value most accurately (Principle 6). By encouraging dynamic response, RTP also meets criteria regarding appropriate investments (Principle 12). RTP would not perform well under criteria related to gradualism (Principle 9).

[63] In August of 1994, the Company proposed an experimental Flexible Time-of-Use Pricing (G-50) tariff that providedbundled hourly energy prices based on the Company's marginal cost of service for purchased power from its affiliate New England Power Company. The Commission approved a settlement with the Division on the Company's proposal in April 1995. *See* Docket No. 2229. The G-50 tariff provided for up to 20 larger customers to receive service pursuant to this tariff, which provided for four price schedules that, under pre- established rules, would be called to be in effect the day before the day of service. The G-50 tariff was terminated in1998 with the unbundling of the Company's rates and the restructuring of the electric markets in New England.

Figure 13.4: Consistency of Rate Designs with Rate Design Principles Described in Docket 4600 (circle shading indicates degree of consistency with principle)

	Principle	Flat Rates	TOU	VPP	CPP	TOU + CPP	TOU + ICAP	RTP + ICAP
1	Ensuring safe, reliable, affordable, and environmentally responsible electricity service today and in the future	●	●	●	●	●	●	●
2	Promoting economic efficiency over the short and long term;	○	◔	◑	◑	◕	◕	●
3	Providing efficient price signals that reflect long-run marginal cost	○	◔	◑	◑	◕	◕	●
4	Appropriately address "externalities" that are not adequately counted in current rate structures	○	◔	◔	◔	◑	◑	◕
5	Empowering consumers to manage their costs	○	◔	◑	◑	◕	◕	●
6	Enabling a fair opportunity for utility cost recovery of prudently incurred costs and revenue stability	●	●	●	●	●	●	●
7	Fair compensation for value and services received and fair compensation for value and benefits delivered	○	◔	◑	◑	◕	◕	●
8a	Being transparent ...	○	◔	◑	◑	◕	◕	●
8b	... understandable to all customers	●	●	◕	◕	◑	◕	●
9	Changes ...implemented with due consideration ... of gradualism, ample time for customers to understand new rates and lessening immediate bill impacts	N/A	◕	◑	◑	◑	◑	◔
10	Providing opportunities to reduce energy burden and address low income and vulnerable customers' needs	○	◔	◑	◑	◕	◕	●
11	Consistent with policy goals such as environmental protection, addressing climate change and the Resilient Rhode Island Act, energy diversity, competition, innovation, power/data security, and least cost procurement	○	◔	◑	◑	◕	◕	●
12	Encourage ... appropriate investments that enable the evolution of the future energy system	○	◔	◑	◑	◕	◕	●

Based on the analysis of different rate structures presented in the TVR Overview and summarized in Figure 13.4, the Company has attempted to select a TOU/CPP rate that is most consistent with the rate design principles laid out in Docket 4600, striking a balance among economic efficiency, customer empowerment, transparency, understandability, while adhering to the principle of rate gradualism.

The Company developed an illustrative rate design that included a time-of-use ("TOU") rate to capture the variation in energy prices and a critical peak pricing ("CPP") rate that reflects generation capacity costs that are a major driver of the supply (i.e., commodity) charges on customers' bills. The illustrative TOU/CPP rate represents a potential solution for developing a default residential supply rate and could serve as a viable baseline against which to test any future alternative rate designs.

The TOU/CPP rate generates benefits for customers through energy and capacity cost reductions while balancing competing rate design criteria. This construct is applied to both the Whole House and to Electric Vehicles and the results are presented separately. Without the Whole House TOU/CCP or the Electric Vehicle TVR benefits, the NPV of the AMF benefits total $565.6 NPV million compared to costs of about $188.0 million NPV. The BCA ratio is 3.0 indicating that TOU/CPP and TVR benefits are not required to guarantee the cost-effectiveness of the AMF program.

13.1 Modeling Whole House TOU/CPP and EV/TVR Benefits

For the purposes of estimating TVR benefits in the BCA, the Company presents benefits from an illustrative TOU/ CPP supply rate, with other rate designs discussed qualitatively and with quantitative sensitivities around the projected customer response and peak reduction percentages to the illustrative TVR design. The rate considered is designed for the residential class only, so all modeled TVR benefits are brought about by this single design and come only from residential usage. Modeled TVR savings do not assume adoption of any additional technology (e.g., in-home displays, smart appliances, etc.) but do assume some education and targeted information going to customers regarding their electricity usage. The program costs for these efforts are included in the cost estimates.

The National Grid Updated AMF Business Case estimated many different benefits associated with TOU, CPP, and TVR associated with EV. For ease of understanding, Rhode Island Energy grouped all benefits associated with Whole House TOU/CPP together and all benefits associated with EV/TVR together in two separate "program" groupings. The results of these programs were shown above in the BCA section and are repeated here for reference.

Figure 13.5: Base Scenario Results for Whole House TOU/CPP Rates

Whole House TOU/CPP - Opt-In (20%)		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
Trans Capacity Benefit: Whole House CPP	$ 58.72	$ 43.25
System Capacity Benefit: Whole House CPP	$ 38.84	$ 28.58
System Capacity Savings: Whole House Time-of-Use (TOU)	$ 7.10	$ 5.23
Dist Capacity Benefit: Whole House CPP	$ 3.40	$ 2.51
Capacity DRIPE Benefit: Whole House CPP	$ 3.42	$ 2.48
Energy Shift Benefits: Whole House Time-of-Use (TOU)	$ 1.26	$ 0.48
Trans Capacity Benefit: Whole House TOU	$ 0.97	$ 0.71
Public Health Benefit: Whole House TOU	$ 0.41	$ 0.28
Non-Embedded CO2 Benefit: Whole House TOU	$ 0.41	$ 0.28
Energy DRIPE Benefit: Whole House TOU	$ 0.13	$ 0.06
Energy Cross DRIPE Benefit: Whole House TOU	$ 0.06	$ 0.03
Dist Capacity Benefit: Whole House TOU	$ 0.26	$ 0.19
Monetized CO2 Benefit: Avoided Energy - Whole House TOU	$ 0.09	$ 0.04
Non-Embedded NOx Benefit: Whole House TOU	$ 0.04	$ 0.03
Total Whole House TOU/CPP	**$ 115.10**	**$ 84.13**

The Base Scenario assumptions for Whole House TOU/CPP include only the Opt-In program which includes only residential customers and has a 20% participation rate that ramps up from

5% to 20% starting in 2026. The assumed CPP peak savings per participant is 20% and that ramps up from 6.7% to 20% over 3 years, also starting in 2026. The energy shift values included reducing peak time kWh by 3.7% and increasing off-peak kWh by 1.6%. The avoided costs used in the calculations were derived from the AESC 2021 report, with the exception of seven benefits where the value of the benefit was taken directly from calculations in the National Grid Updated AMF Business Case. Those seven benefits total $2.4 million nominal and $1.2 million NPV and are listed below:

- Benefit #27: Energy Shift Benefits: Whole House TOU
- Benefit #28: Monetized CO2 Benefit: Avoided Energy – Whole House TOU
- Benefit #700: Non-Embedded NOx Benefit: Whole House TOU
- Benefit #701: Non-Embedded CO2 Benefit: Whole House TOU
- Benefit #702: Public Health Benefit: Whole House TOU
- Benefit #710: Energy DRIPE Benefit: Whole House TOU
- Benefit #711: Energy Cross-DRIPE Benefit: Whole House TOU

Figure 13.6: Base Scenario Results for EV/TVR

EV/TVR Benefit - Opt-In (20%)		
As of November 12, 2022	**Nominal ($M)**	**NPV ($M)**
Trans Capacity Benefit: EV TVR	**$ 58.90**	**$ 41.89**
System Capacity Benefit: EV TVR	**$ 43.41**	**$ 30.86**
Dist Capacity Benefit: EV TVR	**$ 3.79**	**$ 2.70**
Energy Shift Benefits: EV TVR	**$ 2.08**	**$ 1.51**
Capacity DRIPE Benefit: EV TVR	**$ 1.32**	**$ 0.50**
Public Health Benefits: EV TVR	**$ 1.15**	**$ 0.79**
Non-Embedded CO2 Benefit: EV TVR	**$ 1.13**	**$ 0.78**
Monetized CO2 Benefits: EV TVR	**$ 0.26**	**$ 0.17**
Energy DRIPE Benefit: EV TVR	**$ 0.22**	**$ 0.12**
Non-Embedded NOX Benefit: EV TVR	**$ 0.10**	**$ 0.07**
Energy Cross DRIPE Benefit: EV TVR	**$ 0.09**	**$ 0.07**
Total EV/TVR Benefits	**$ 112.45**	**$ 79.46**

The Base Scenario assumptions for EV/TVR are more complicated than for the Whole House TOU/CPP. Before the peak savings and participation rate percentages can be considered, a forecast of the number of electric vehicles, their energy usage and their contribution to the system peak must be developed. Based on current electric vehicle sales and the number of EVs needed for Rhode Island to meet its Climate Mandates, Rhode Island Energy forecasts the number of EVs starting at approximately 7,000 vehicles in 2022 and increasing to ~750,000 vehicles in 2041.

Energy use per vehicle is forecast to increase from ~4,000 kWh/yr/vehicle in 2026 to 4,300 kWh/yr/vehicle, resulting from the changing mix of electric vehicles from mostly sedans to a more balanced mix of sedans and trucks/SUVs. Similarly, the peak contribution is forecast to increase from 0.68 kW/vehicle in 2026 to 1.38 kW/vehicle in 2041. This is partly due to the mix of vehicles and partly due to the changing time of the system peak (going later in the day and ultimately switching to a winter peak).

Once the Company forecast the impact of electric vehicles on the electric system, it developed forecasts of participation rates, energy shifts and peak savings. Participation rates were forecast on an Opt-In program and grow from 5% to 20% starting in 2026 through 2029 and remain at 20% for the remainder of the study period. Energy shifts involved increasing reductions of EV energy use during the peak period, starting at 19% in 2026, the first year of the program, and increasing to 27% by 2041.

Peak hour reductions were forecast to increase as well, from 42% in 2026 to 60% in 2041. The resulting kWh and kW savings were multiplied by annual avoided costs from AESC 2021.

Similar to Whole House TOU/CPP, Rhode Island Energy used values directly from the National Grid Updated AMF Business Case for a subset of benefits. The subset included seven benefits which totaled $4.3 million nominal and $2.5 million NPV and are listed below.

- Benefit #722: Monetized CO2 Benefits: EV TVR
- Benefit #723: Non-Embedded NOx Benefit: EV TVR
- Benefit #724: Non-Embedded CO2 Benefit: EV TVR
- Benefit #725: Public Health Benefit: EV TVR
- Benefit #726: Capacity DRIPE Benefit: EV TVR
- Benefit #727: Energy DRIPE Benefit: EV TVR
- Benefit #728: Energy Cross DRIPE Benefit: EV TVR

13.2 Whole House TOU/CPP and Electric Vehicle TVR Sensitivities

Customer response to Whole House TOU/CPP and Electric Vehicle TVR can help increase the cost-effectiveness of the AMF program. Figure 13.7 and Figure 13.8 illustrate the sensitivity of both customer participation and the peak reduction achieved by participating customers. Rhode Island Energy made these simplifying assumptions to the TVR sensitivities because well over 90% of the overall benefits from the programs are captured by peak savings rather than energy savings. Below are the sensitivity assumptions and results based on the Whole House Time-of-Use/Critical Peak Pricing ("TOU/CPP") program.

Figure 13.7: Sensitivity Analysis of Whole House Critical Peak Pricing Program

Whole House CPP Capacity Benefits Sensitivities						
As of November 12, 2022						
Sensitivity #	Participation Rate (%)	Peak Reduction (%)	Nominal Benefits ($M)	NPV Benefits ($2022M)	Nominal B/C Ratio	NPV B/C Ratio
1	5%	26%	$983.2	$673.2	3.4	3.6
2	10%	25%	$1,017.0	$698.1	3.5	3.7
3	15%	24%	$1,048.0	$720.9	3.6	3.8
4	20%	20%	$1,059.3	$729.2	3.7	3.9
5	30%	18%	$1,098.8	$758.2	3.8	4.0
6	40%	16%	$1,126.9	$778.9	3.9	4.1
7	50%	14%	$1,143.8	$791.4	4.0	4.2
8	60%	12%	$1,149.5	$795.5	4.0	4.2
9	70%	10%	$1,143.8	$791.4	4.0	4.2
10	80%	8%	$1,126.9	$778.9	3.9	4.1
11	90%	6%	$1,098.8	$758.2	3.8	4.0
Base Scenario						

As shown in Figure 13.7, Rhode Island Energy chose a conservative Base Scenario which results in a nominal BCA ratio of 3.7 and a NPV BCA ratio of 3.9. Varying the participation rate and peak reduction as shown results in nominal CA ratios ranging from 3.4 to 3.8 and NPV BCA ratios ranging from 3.6 to 4.0.

Figure 13.8: Electric Vehicle TVR Capacity Benefit Sensitivities

Electric Vehicle (EV) TVR Capacity Benefits Sensitivities							
As of November 12, 2022							
Sensitivity #	Participation Rate (%)	Initial Peak Reduction Factor	Peak Reduction (%)	Nominal Benefits ($M)	NPV Benefits ($M)	Nominal B/C Ratio	NPV B/C Ratio
1	5%	1.30	Varies by Year from 9% to 78%	$986.8	$677.9	3.4	3.6
2	10%	1.25		$1,019.0	$700.7	3.5	3.7
3	15%	1.20		$1,048.6	$721.6	3.6	3.8
4	20%	1.00		$1,059.3	$729.2	3.7	3.9
5	30%	0.90		$1,096.9	$755.8	3.8	4.0
6	40%	0.80		$1,123.7	$774.8	3.9	4.1
7	50%	0.70		$1,139.9	$786.1	3.9	4.2
8	60%	0.60		$1,145.2	$789.9	4.0	4.2
9	70%	0.50		$1,139.9	$786.1	3.9	4.2
10	80%	0.40		$1,123.7	$774.8	3.9	4.1
11	90%	0.30		$1,096.9	$755.8	3.8	4.0
Base Scenario							

To perform sensitivities on the EV TVR assumptions, the Company used "Initial Peak Reduction Factors" to adjust the peak reductions year by year. This approach was used because the peak reduction in the base scenario is assumed to grow over time from 42% in 2026 to 60% in 2041. Varying the participation rate and peak reduction as shown results in a range of nominal BCA ratios of 3.4 to 4.0 and NPV BCA ratios of 3.6 to 4.2.

Figures 13.7 and 13.8 show the impact of varying participation rates and peak reductions on the Whole House and Electric Vehicle programs individually. Figure 13.9 depicts the results if both programs are varied similarly. As can be seen, the BCA ratios remain very strong, ranging from 3.2 to 4.6 for nominal BCA ratios and from 3.3 to 4.3 for the NPV BCA ratios.

Figure 13.9: Whole House and Electric Vehicle Sensitivities Combined

Whole House TOU/CPP & EV TVR Capacity Benefits Sensitivities				
As of November 12, 2022				
Sensitivity #	Nominal Benefits ($M)	NPV Benefits ($M)	Nominal B/C Ratio	NPV B/C Ratio
1	$910.7	$621.9	3.2	3.3
2	$976.8	$669.6	3.4	3.6
3	$1,037.3	$713.3	3.6	3.8
4	$1,059.3	$729.2	3.7	3.9
5	$1,136.3	$784.8	3.9	4.2
6	$1,191.4	$824.5	4.1	4.1
7	$1,224.4	$848.4	4.4	4.2
8	$1,235.4	$856.3	4.5	4.3
9	$1,224.4	$848.4	4.6	4.2
10	$1,191.4	$824.5	4.5	4.1
11	$1,136.3	$784.8	4.4	4.2
Base Scenario				

13.3 AMF as an Enabling Platform for TVR

Rhode Island Energy is not making a rate design proposal in this Business Case or in this TVR section. Instead of presenting a single proposal, the Company presents a series of considerations that influence TVR and develops a suite of options for the PUC to consider. The insights from this research apply across all rate classes.

TVR are important for two reasons, both of which benefit customers. First, by more accurately reflecting the costs of producing and delivering electricity, they promote economic efficiency which will lead to a lower-cost system. Second, by more closely aligning the prices consumers pay with the underlying costs they represent, TVR promote a fairer, more equitable allocation of electricity sector costs to the customers responsible for those costs.

Moreover, TVR are a powerful tool in the fight against climate change. Clean electricity paired with increased electrification of sectors which previously relied on fossil fuels will be a backbone of a more sustainable economy. Under this scenario, which places new demands on the electric sector, it will be even more important that electric services are priced fairly and appropriately. If the variation in carbon emission rates become priced into TVR, thus aligning off-peak periods with the lowest carbon generation, customer response can facilitate a cleaner sector.

Rhode Island Energy is committed to delivering a safe, reliable, and cost-effective energy system for Rhode Island. AMF is an important part of the update to the technology platform the Company needs to meet increasing operational and customer demands. TVR offers the potential to more accurately price energy and energy services. Such rates can lower costs for customers over long-time horizons and allocate costs more fairly as they are implemented.

If the PUC approves this AMF Business Case, Rhode Island Energy will subsequently make a TVR proposal that delivers benefits to customers that meet or exceed those modeled in the Business Case as part of a future filing.

Section 14

SECTION 14: CONCLUSION

This section offers a proposal to report updates, recommends metrics to be used to manage performance and presents a summary of the filing.

Rhode Island Energy has determined that a full-scale AMF implementation is best suited to meet its customers' current and future needs by facilitating access to clean energy programs while at the same time enabling control capabilities that can most effectively respond to system reliability challenges. The evaluation of various alternatives, including the continuation of the legacy AMR meter system, demonstrated that a full-scale roll-out of AMF would be the most cost-effective solution and most consistent with the objectives of the Docket 4600 Framework, while also providing the best cyber-secure technology platform of communications infrastructure. This AMF proposal also is projected to save Rhode Island Energy's customers $729.2 million in $2022 over the next 20 years, which translates to a BCA ratio of 3.9.

The extensive research and analysis on the BCA for AMF, coupled with PPL's experience in Pennsylvania and Kentucky, leads to the same conclusion as other utilities that have already implemented AMF; that is, the significant investment will benefit customers and stakeholders. PUC approval of this AMF Business Case will put the State of Rhode Island and the Company on a pathway to a more modernized and efficient electric system by transforming the electric grid from the traditional business-as-usual power system to a modern-day system that is capable of successfully meeting the challenges of the 21st century energy demand.

14.1 Reporting Approach and Metrics

Achieving the potential that is presented in this Business Case is directly dependent upon realizing the AMF benefits that support this AMF Business Case. The success of achieving the benefits can be bolstered through effective program reporting. For the purposes of reporting, Rhode Island Energy is proposing to report on progress across the following broad categories, noted below, which align with the most critical elements and drivers of the Business Case.

1) **Program Implementation:** metrics focused on progress relatedto deployment and delivery of functionalities.

2) **Customer Focused:** customer engagement metrics that target key drivers of enabled customer benefits

3) **Operations:** metrics targeting drivers of operational benefits

This suite of reporting metrics provided in Figure 14.1 is intended to provide a transparent assessment of the Company's AMF implementation progress in key areas of interest to customers, regulators, and stakeholders. During AMF deployment, Rhode Island Energy proposes to file an annual AMF Program Report with the PUC by December 31, annually that is based on the metrics listed in Figure 14.1, below r and provide a mid-year project status update meeting. The annual reports that PPL filed with the Pennsylvania Public Utilities Commission to provide progress updates for their second-generational AMF project implementation will be customized for AMF Project implementation in Rhode Island. Examples of these annual reports are provided in Attachment B.

Figure 14.1: Reporting Metrics

Benefit Category	Benefit Metric
Program Implementation	**Major Project Release progress** Progress of AMF Program Functionality Releases
	Meter Pre-Sweep Completions Counts of Completed Pre-Sweeps
	Network Deployment Counts of Completed Device Installs
	Meter Deployment Counts of Completed Exchanges
	Meter Base Repairs Counts of Meter Bases requiring repairs prior to meter exchange
	Sector Completion Sector Acceptance Status
	Program Spend Costs Breakdown Summary for key categories of the AMF Program
Customer	**Customer Interactions** Counts and reasons for customer contacts to the AMF Program
	Customer Portal Enrollments Counts of customers signing up for Customer Portal access
	Delivery of CP Functionality Update of functionality available
	Customer Surveys / Customer Satisfaction Breakdown of Customer Satisfaction survey results of AMF communication, access to information & FAQs, and issue resolution
	Customers Accessing Green Button Connect Data Counts of customers who have exported their Green Button Connect data
	Customers who Opt out of AMF meter Count of customers who have elected to Opt Out from receiving an AMF meter

Figure 14.1: Reporting Metrics (continued)

Benefit Category	Benefit Metric
Operations	**Billing Read Rate** Register meter reads expected vs. delivered
	Interval Read Rate Interval meter reads expected vs. delivered
	MDMS estimates sent to Billing Percentage of meters requiring estimates for billing
	Remote Switch Performance Percentage success rates of remote switches
	Last Gasp Alerting Percentage of Last Gasp alerts successfully delivered to the OMS
	VVO metric Number of feeders with AMF deployed that have implemented Volt Var Optimization

14.2 AMF Business Case Provides Evidence to Act Now

The increased penetration of DERs, reinforced by the State of Rhode Island's Climate Mandates, has created additional system complexity that today's electric grid simply cannot handle. It requires adjustments to how the electric distribution grid is used and operated to achieve the State's vision for a cleaner, more efficient and modernized electric distribution system, while still serving customers reliably and safely. AMF is a bedrock technology that is necessary for this transformation to happen. To maintain electric system safety and reliability and keep pace with this once-in-a-lifetime transformation, Rhode Island Energy must invest in the development of a safer and modernized grid that provides advanced functionality, such as more frequent system information for grid operators and more granular billing and usage information for customers.

The AMF infrastructure contemplated in this Business Case is foundational to facilitating this transformation through enhanced delivery of various customer programs and utility best practices including: DER net-metering; distribution system asset monitoring; situational awareness, measurement and control; responsive load control and DR opportunities; and future possibilities given the added versatility of the AMF technology platform.

The energy distribution system of the next twenty years must enable Rhode Island Energy's obligation to provide safe and reliable service, as well as enable distributed energy markets that can be leveraged both by customers and third-party service providers. Given the wide-ranging functionalities of the AMF platform, including the future possibilities given the versatility of the AMF technology platform, the Company has determined that the AMF technology platform proposed in this Business Case will constitute one of the most dynamic and foundational components of the grid modernization evolution, enabling precise measurements of voltage, current flows, and energy consumption that can be leveraged for potential control capabilities and the development of appropriate rate structures, as envisioned by the PUC's 's Docket 4600 Framework.

For the reasons discussed herein, this AMF Business Case supports a finding that AMF is a necessary investment on its own and should move forward expeditiously. First the BCA for AMF is strong with or without the integration of grid modernization. Second, because the ADMS Basic system is being made available to Rhode Island Energy through the Acquisition, the Company's AMF proposal is capable of unilaterally delivering nearly all benefits featured in this Business Case.[64] Also, the granular information that AMF provides is foundational to and enhances many grid modernization functionalities. Finally, this AMF Business Case demonstrates that full deployment of AMF is critical for the State of Rhode Island to meet its Climate Mandates. As a result, it is reasonable and prudent to move forward with AMF now. Accordingly, the Company requests that the PUC find that the AMF Business Case demonstrates substantial customer and system safety and reliability benefits that significantly exceed the projected costs (on a NPV and nominal basis), and, approve the Company's AMF proposal and implementation plan as contained in this Business Case.

[64] The exception is the benefits from VVO, which is co-dependent on GMP investments.

Summary of Attachments

SUMMARY OF ATTACHMENTS

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Attachment A

COMPLIANCE WITH RHODE ISLAND DOCKET NO. 4600

Section A1: AMF Program Alignment with Docket No. 4600 Goals and Principles

Rhode Island Energy's AMF Project is in full alignment with goals and principles that the PUC adopted in Docket No. 4600. In that proceeding, the PUC adopted a set of goals, rate design principles, and a new Rhode Island benefit-cost framework for use in future dockets.[1] The Docket 4600A Guidance Document discusses the application of each element and specifies that any proponent of a program proposal with associated cost recovery will need to explain how a new program or capital investment advances, detracts from, or is neutral to the Docket 4600 goals. The application of the Docket 4600 Framework is further discussed below.

According to the PUC's directive, the Docket 4600 Framework should serve as a starting point in making a business case for a proposal, but also makes clear that it should not be the exclusive measure of whether a specific proposal should be approved.[2] The PUC recognized that there may be outside factors that need to be considered regardless of whether a specific proposal is determined to be cost-effective or not, such as statutory mandates or qualitative considerations, and that such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates. Similarly, Rhode Island Energy's statutorily-imposed duties as a chartered public utility includes an affirmative obligation to provide safe, adequate and reliable service.[3] For the remaining components of the AMF program, the benefits and costs are evaluated holistically for the entire program, and the demonstrated alignment with the Commission's goals and objectives are centered on AMF's functionalities and outcomes for the electric system, such as providing customers with data and information to help inform their energy decisions and reduce their electricity consumption. Additionally, AMF will improve outage detection and restoration timeframes, and provide grid-edge sensing capabilities for improving system reliability through operational advancements such as a Distributed Energy Resource Management System ("DERMS"). Time-Varying Rates ("TVR"), enabled by AMF, can encourage customers to reduce energy demand and consumption through actionable and timely data, which will be critical for responding to the growing charging demands of electric vehicles.

A complete assessment of how AMF aligns with Commission's vision for the future electric system is listed in Figure A.1 below:

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1 *See* Report and Order No. 22851 at 6, 29.

2 *Id*. at 23.

3 RIGL Section 39-2-1.

Figure A.1: Alignment Between Docket No. 4600 Goals and AMF Objectives

Docket 4600 Goals for the Electric System	Alignment with AMF Program Investments
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term	AMF can contribute to incremental benefits in this area by integrating granular AMF voltage data into voltage optimization and conservation control schemes. In addition, AMF will enable customers to become more active in managing and reducing their energy usage through enhanced energy insights (i.e., High Bill Alerts) or integrating AMF with in-home technologies.
Strengthen the Rhode Island economy, and supporting economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	AMF is a foundational component of grid modernization and represents a significant investment that will bring direct and indirect economic benefits in the form of implementation spending and job creation in Rhode Island, including induced impacts to the local service sector, such as increased retail activity.
Address the challenge of climate change and other forms of pollution	AMF, in conjunction with the broader GMP strategy, will reduce greenhouse gases (GHGs) and other harmful emissions by enabling reduced energy use (e.g., VVO/CVR, High Bill Alerts). AMF will enable customers to become more active in managing and reducing their energy usage. Finally, additional emissions reductions will be realized due to a reduction in truck rolls due to improvements in operational efficiency.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	AMF will provide more granular data to customers (e.g., detailed billed energy use, in-home devices) that can enable third-party programs and offerings that will help drive innovation; enable more cost-effective utilization of EVs through future TVR applications that incentivize customers to move vehicle charging to off-peak periods; and more cost-effective DER investment due to system information sharing via an integrated data portal.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	AMF, through enablement of TVR applications, can more directly and accurately compensate DERs for their intrinsic value, including participation in wholesale energy and capacity markets.
Appropriately charge customers for the cost they impose on the grid	AMF, in combination with TVR and other GMP investments, will enable new rate designs and pricing mechanisms that can allocate costs and benefits more equitably.
Appropriately compensate the distribution utility for the services it provides.	The ability to monitor two-way power flows will allow the Company to better manage the impacts of DER and assess the value that the grid provides to both consumers (i.e., ratepayers) and producers (i.e., DER customers) and thereby appropriately compensated the utility for the services it provides.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.	AMF provides improved customer data access and enhances existing customer programs in EE, DR, and EVs. When coupled with future rate designs and incentives, AMF also aligns customer and utility interests with policy objectives by providing customers with greater choice and control over energy usage while providing the Company with better visibility of its distribution system, leading to a cleaner, more efficient electric distribution grid.

Section A.2: Mapping of Docket 4600 Benefit Categories to the AMF BCA

Figure A.2 lists each category of the Docket 4600 Framework and indicates if the category is quantified in the Company's BCA presented in Section 11 of the Business Case. The manner in which the categories either are factored into the BCA or omitted appears in the fourth column.

Figure A.2: Benefit Categories Included in the Docket 4600

Docket 4600 Level	Benefit Category	Quantified in Filing?	Treatment in AMF BCA or reason for exclusion
Power Sector	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Yes	Included in avoided energy costs
Power Sector	REC Value	Yes	Included in avoided energy costs as Embedded CO2 Benefit
Power Sector	Retail Supplier Risk Premium	Yes	8% supplier markup included in avoided energy and capacity costs
Power Sector	Forward Commitment Capacity Value	Yes	Capacity market savings included for Critical Peak Pricing (CPP)
Power Sector	Forward Commitment Avoided Ancillary Services Value	No	Excluded because ancillary services would be very small
Power Sector	Electric Transmission Capacity Value	Yes	Included as separate benefits resulting from various benefit programs
Power Sector	Net Risk Benefits to Utility System Operations from DER Flexibility & Diversity	No	Not directly measured although visibility resulting from AMF will reduce risks on system
Customer	Option Value of Individual Resources	No	Difficult to quantify outside of portfolio analysis of multiple resources
Customer	Investment Under Uncertainty: Real Option Value	No	Likely very small impact due to significant benefits from AMF
Power Sector	Energy Demand Reduction Induced Price Effect (DRIPE)	Yes	Intrastate DRIPE and cross DRIPE included

Docket 4600 Level	Benefit Category	Quantified in Filing?	Treatment in AMF BCA or reason for exclusion
Societal	Green House Gas (GHG) Externality Cost	Yes	Included in avoided energy costs as Embedded CO2 Benefit
Societal	Criteria Air Pollutant and Other Environmental Compliance Costs	Yes/No	Avoided NOx costs and Public Health benefits are included. Other criteria air pollutants not included
Societal	Innovation and Learning by Doing	No	Not applicable to AMF
Power Sector	Distribution Capacity Costs	Yes	Included as benefit for Electric Vehicle TVR rates and Whole House CPP rate
Power Sector	Distribution Delivery Cost	Yes	Benefits from reduced operational and infrastructure costs are included
Power Sector	Distribution System Performance	Yes	Benefits from conservation voltage reduction (CVR/VVO) are included
Customer	Utility Low Income	Yes	Benefits from Reduced Electricity Theft and Electromechanical Meter Accuracy are transfer payments that provide more equitable electricity bills for all customers
Power Sector	Distribution System and Customer Reliability Resilience Impacts	Yes	Included in VVO/CVR benefits and Faster Outage Notification benefit
Customer	Distribution System Safety Loss/Gain	No	Reduced damage claims not included by RIE due to inability to verify
Customer	Program Participant/Prosumer Benefits	Yes	Included as Electric Bill Reductions for Energy Insights

Customer	Participant non-energy benefits; oil, gas, water, waste water	No	Incremental EV adoptions may result from improved ability to facilitate home charging but excluded gasoline savings and vehicle incremental costs from the analysis to avoid double-counting with EV initiatives
Customer	Low-Income Participant Benefits	Yes	All customers have an opportunity to use the data from AMF meters to save energy
Customer	Customer Empowerment & Choice	Yes	Customers have much more choice when they have near real-time information on their electricity use
Customer	Non-Participant Rate and Bill Impacts	Yes	Quantified at the aggregate utility level
Societal	GHG Externality Cost	Yes	Non-embedded CO2 costs are included
Societal	Criteria Air Pollutant and Other Environmental Compliance Costs	Yes	Non-embedded NOx costs are included
Societal	Conservation and Community Benefits	No	Likely little or no impact for AMF
Societal	Non-energy benefits: Economic Development	No	Will likely be economic development benefits but they are not included in BCA

Attachment B

PPL BUSINESS BENEFITS FROM 15-MINUTE AMF INTERVAL DATA AND PPL ELECTRIC 2020 ANNUAL REPORT

In Pennsylvania, PPL continues to leverage its AMF investment and realize a business value that goes well beyond measuring energy consumption. The comprehensive, granular data perspectives offered by AMF provide insight into common patterns associated with system or local events that utility staff can utilize to identify and address issues, oftentimes before they occur. This not only improves business processes, but also increases overall efficiency as resources are focused where and when they are most needed.

PPL has incorporated interval data from AMF in the form of 15-minute usage and voltage data into several core business functions. Examples of the resulting business benefits that have been realized in Pennsylvania by having more granular voltage and usage information are included in the table below and is illustrative of the AMF business benefits that will be afforded to Rhode Island Energy and its customers.

Benefit	***Business Function***
• Provide insights into different types of heating and cooling sources in the home to better direct energy efficiency resources and recommend improvements where they are most needed	Analytics
• Identify EV charging, or other DER installations in the home to ensure regulatory compliance and accurate metering	Analytics
• Monitor momentary service interruptions (less than five minutes) to proactively identify and address issues on the distribution network	Analytics
• Offer Time of Use, Real Time Pricing, and other Complex Billing rates to customers	Billing
• Provide more accurate end reads for meters that stopped communicating by averaging actual, corresponding 15-minute usage intervals (like days and like times) from the prior three weeks, and comparing the estimated totals with actual, historical usage totals	Billing

Benefit	*Business Function*
• Provide up to date, 15-minute interval usage data to Customer Service Representatives and Billing Specialists so they can investigate and resolve billing issues more quickly and accurately	Billing
• Calculate unbilled revenue at the end of each month for accounts where the associated billing period does not directly align with the calendar month	Billing
• Identify and resolve meter issues from the office by monitoring automated meter alerts in conjunction with 15-minute temperature, load, current and voltage values	Operational analysis
• Investigate meters that are communicating with the Head End system without an assigned account number; 15-minute interval usage data reveals load type: residential, commercial, or industrial.	Operational analysis
• Diagnose meter and other system events that trigger alerts and alarms in the Head-End system by reviewing 15-minute interval usage data to determine if and/or how concurrent load contributed to the issue	Operational analysis
• Identify potential tampering issues revealed by characteristic interval data usage patterns; collaborate with Revenue Protection for further investigation and resolution	Operational analysis
• Identify voltage anomalies and fluctuations from 15-minute interval voltage data perspectives; collaborate with Reliability Engineering for further investigation and resolution	Operational analysis
• Calculate percent power factor from 15-minute interval reactive power (kVAR) and energy usage (kWh) values to identify inefficiencies on the distribution network	Operational analysis

Benefit	***Business Function***
• Calculate total usage from 15-minute interval usage data and send it to the ISO so a supplier can compare ISO usage with their bill	Settlement
• Calculate Unaccounted for Energy ("UFE") which is a comparison between the total load from ISO and an aggregation of all 15-minute interval data in the Meter Data Management System	Settlement
• Support Settlement by providing aggregated 15-minute interval usage data perspectives to identify and resolve discrepancies	Supplier Coordination
• Provide 15-minute interval usage data to suppliers through the Supplier Portal or through EDI transactions, which allows them to: o better tailor offerings to customers through detailed energy insights (e.g., TOU programs, free Saturday or Monday programs, etc.) o ensure they procure enough power by calculating total usage for all their customers o have awareness of large usage swings during weekends for customers with different rate classes, especially industrial customers with higher loads	Supplier Coordination

PPL ELECTRIC'S SMART METER IMPLEMENTATION PLAN (SMIP) PROGRESS REPORTS

The Pennsylvania Public Utility Commission ("Pennsylvania Commission") approved PPL Electric Utilities Corporation's ("PPL Electric") Smart Meter Implementation Plan ("SMIP") at Docket No. M-2014-2430781 on September 3, 2015. Progress reports were submitted annually to the Pennsylvania Commission which summarized progress to plan relating to the functionality schedule, meter installations and costs. Below is the PPL Electric 2020 Annual Progress Report which demonstrates PPL's experience and effectiveness at implementing large scale second-generation AMF deployments and serves as an example of the type of progress reports that could be customized for Rhode Island Energy's AMF program and filed with PUC annually.

Contents

Introduction

On September 3, 2015, the Pennsylvania Public Utility Commission (Commission) approved PPL Electric Utilities Corporation's (PPL Electric or Company) Smart Meter Implementation Plan (SMIP) at Docket No. M-2014-2430781. Pursuant to the Implementation Order entered by the Pennsylvania Public Utility Commission (Commission) on June 24, 2009, at Docket No. M-2009-2092655, PPL Electric submits this smart meter progress report for the third period, July 31, 2019 to July 31, 2020 (Current Reporting Period).

The program is on schedule to conclude by the end of 2020; meetings objectives with planned functionality, meter installs, and cost.

PPL Electric oversees a team of program vendors to assist with the planning and implementation of all aspects of the program. Black & Veatch's role on the Project is to provide PPL Electric with program management services and system integration services. Black & Veatch replaced IBM in August 2017.

The Company's technology supplier and meter vendor is Landis + Gyr. They are providing the radio frequency network, Automated Metering Infrastructure (AMI) head end, meter data management system (MDMS), meters and installation services. They are supported by Grid One and Riggs-Distler for network installation, meter installation and meter base repairs. Tesco Services performs quality auditing of work performed.

GE-Digital is providing Mix Director, the primary software system that the Company will use to monitor the AMI network during deployment and in future operations.

Watthour Engineering Company (WECO) is providing the new meter asset management (MAM) system and test boards that is used to test and track meters and network devices.

Black & Veatch provided project management and end-to-end systems integration services.

Landis + Gyr (L+G) is our vendor for the AMI network devices, AMI meters, meter and network deployment, AMI Head End system and Meter Data Management System (MDMS).

GE Digital provided **MIx Director**, the primary system that Advanced Metering Operations (AMO) will use to monitor the AMI network.

WECO provided the new **Meter Asset Management (MAM)** system and test boards that will be used to test and track meters and network devices.

Riggs Distler, an authorized sub-contractor of L+G, completed meter base repairs and installed high-end meters, and removed inactive PLC meters that do not need to be exchanged for AMI meters

Grid One, an authorized sub-contractor of L+G, installed the AMI meters, performed the meter inspection activities, and hosted a call center.

Program Scope

PPL Electric's Smart Meter Implementation Plan (SMIP) was designed to meet the Act 129 requirements by first deploying the systems and infrastructure required to enable the new Automated Metering Infrastructure technology. This was then followed by the deployment of radio frequency (RF) meters replacing PPL Electric's existing 1.4 million power line carrier (PLC) meters over a four-year period.

The following items were deployed as part of the program:

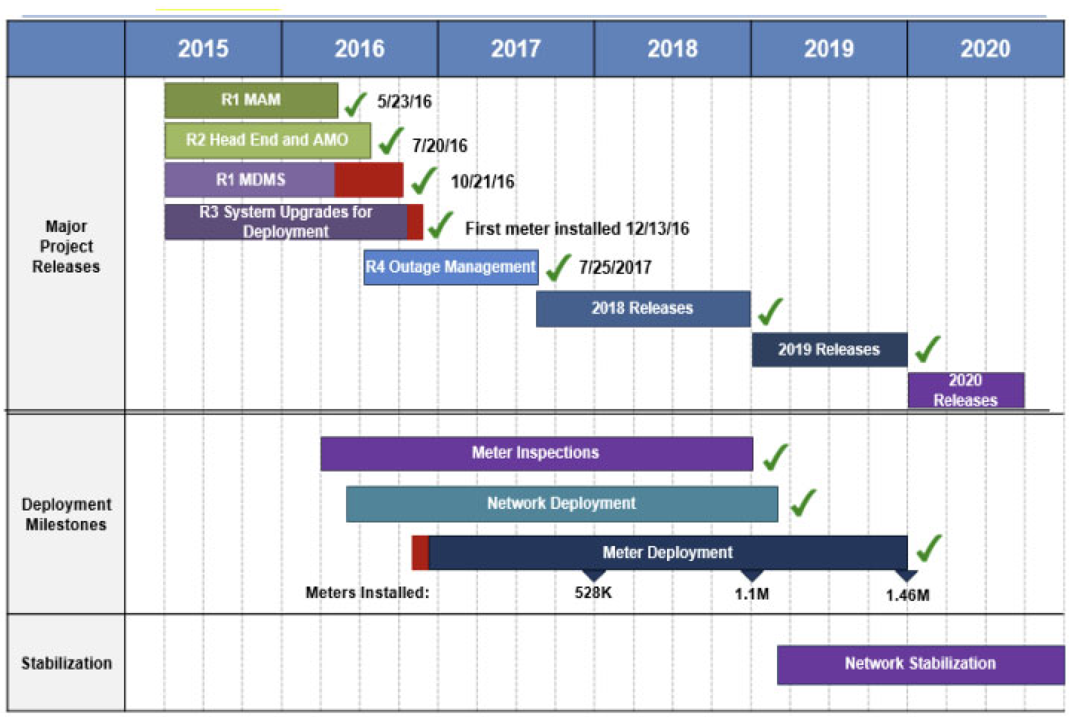
- **Customer Web Portal** – The portal was updated to display the customer's interval usage
- **Electric meters** – Use two-way communication to collect electricity usage and related information from customers and to deliver information to customers
- **Local Area Network (LAN) Collectors and Routers** – Devices used to relay and collect meter data from all meters in a local area and transmit to the head end through a wide area network
- **Wide Area Network (WAN) Fiber and Cellular Backhaul** – Communications infrastructure responsible for transmitting the meter data to the head end
- **AMI Head End** – System that receives the stream of meter data from the field making the data available for other systems

- **Meter Data Management System (MDMS) –** System that collects and stores meter data from the head end system and processes that data into information that can be used by other applications including network operations, customer information system, analytics and asset management
- **Meter Asset Management Tool –** Tool used to store the meter and network components information and manages the life cycle of the asset
- **Mix Director –** Tool used to track and perform analysis and analytics on meter and network information, along with deployment and operations
- **Home Area Network (HAN) Devices -** Customer-owned devices that connect via Zigbee to the meter and display energy usage information

Release Schedule

All of the systems and technology previously mentioned have been deployed or will be deployed by the end of 2020. The information technology release schedule below covers the initial deployment of the systems followed by releases of additional capabilities. Releases 1 through 3, completed in 2016, were foundational to enable functionality for the deployment of the radio frequency (RF) meters. Subsequent releases enable advanced capabilities.

Below is an overview of the releases followed by a description of the enabling capabilities.



2018 Releases	2019 Releases	2020 Releases
Support for a subset of enhanced RF functionality and operational efficiencies ▪ AMI to OMS – Restoration (Power Up) messages for restored customers and Customer Service IVR ping capability ▪ Command Center 7.1 MR3 – Production Upgrade ▪ Home Area Network (HAN) Pilot ▪ Priority Meter Alerts to Automated Filed Ticket Creation ▪ Inventory Badge Scanning ▪ Added Service Delivery Point (SDP) to Electric Facilities Database (EFD) ▪ Enhance Analytics Mix Director Work Bench	*Support for a subset of enhanced RF functionality and operational efficiencies* ▪ Network Model Validator – Identifying meter to transformer mismatches (AMI to OMS improvements) ▪ Mix Director Upgrade ▪ Polyphase Meter Diagnostic Notifications ▪ MDMS Enhancements - Estimates to CSS for Billing ▪ Nominal Voltage ▪ Command Center 7.3 MR2 – Production Upgrade Meter Asset Management updates to support Return Merchandise Authorization (RMA) process and improved inventory tracking ▪ Home Area Network Program ▪ Begin transition of RF Network Management to PPL	*Support for a subset of enhanced RF functionality and operational efficiencies* ▪ RF Network Management transition to PPL, including Field Backoffice Support ▪ Deployment of Advanced Security Devices ▪ Meter Asset Management updates to support Meter Failure Tracking and reporting ▪ Revenue Protection & AMI advanced analytics

Deployment

The Company's deployment plan was executed in accordance with the Smart Meter Plan. The full-scale deployment of RF meters began in December 2016 with mass deployment completed the end of 2019.

Meter deployment is broken into three distinct phases:

- Meter inspections, or pre-sweeps, were performed to identify issues or barriers to be resolved prior to physical meter deployment. An example is the identification of meter bases that need repair or replacement for a successful meter exchange.
- Network deployment is the build-out of the AMI network infrastructure of collectors and routers to transmit data and information from the meter to the AMI head-end system.
- Meter deployment is the physical replacement of the Company's existing PLC meters to new RF meters.

The first three deployment phases occurred on a regional basis sequentially through PPL Electric's six major operating regions: Harrisburg, Lancaster, Lehigh, Northeast, Central, and Susquehanna. The final phase occurred across the entire service area based on resource availability and need.

Meter Inspections

PPL Electric precedes physical meter deployment with a meter inspection phase. This work began in October 2015 and occurred approximately six to eight months prior to meter installations in a given region. Meter inspections finished in at the end of 2018 with a total of 1.39 million inspections completed across PPL Service Territory.

These inspections identified any Rules for Electric Meter Service Installation (REMSI) violations; REMSIs are the Company's standards for meter installations. As stated earlier, PPL Electric was also able to anticipate meter base repairs that will be required in the course of meter deployment.

Network Deployment

Deployment of the radio frequency network preceded meter installation by approximately five months. Planned RF network build out was completed in early 2019. After the initial deployment of the network components, additional work remains to optimize the network and provide support for maximum effectiveness. RF network optimization will continue through stabilization.

Collectors are being installed to form the backbone of the radio frequency network. These collectors are the "take out points" for all network data and they communicate back to the AMI Head End via cellular communications or optical fiber. As of July 31, 2020, 255 collectors have been installed with 67 collectors deployed as a part of network optimization.

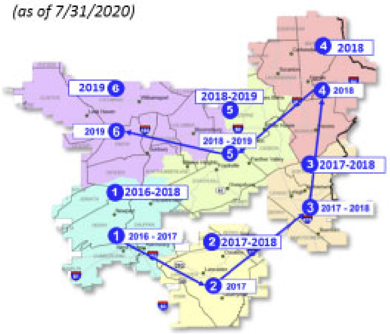
Routers will support collectors as a part of the RF Network. Routers are radio frequency devices that intercede between meters and other routers to ensure a fully formed radio mesh network allowing for a variety of communication paths from meter to collector. As of July 31, 2020, 5,077 routers have been installed with approximately 427 deployed through network optimization.

Meter Deployment

RF meter exchanges began in the Harrisburg region in December 2016, the Lancaster region in July 2017, the Lehigh region in November 2017, the Northeast Region in May 2018, the Central Region in Oct 2018, and Susquehanna Region in March 2019.

As of July 31, 2020, 1,467,105 meter exchanges have been completed. Mass meter deployment is complete in all regions. There are 40 remaining meter endpoints that still have PLC meters on them. These locations are on hold due to PUC complaint proceedings and will be exchanged when the approval to proceed is granted.

(as of 7/31/2020)



Region	Pre-Sweep Inspections	Network Installations	Mass Meter Deployment	PPL UTC Clean Up
1. Harrisburg	Complete	Complete	Complete	100.00%
2. Lancaster	Complete	Complete	Complete	100.00%
3. Lehigh	Complete	Complete	Complete	100.00%
4. Northeast	Complete	Complete	Complete	100.00%
5. Central	Complete	Complete	Complete	100.00%
6. Susquehanna	Complete	Complete	Complete	100.00%

Note: 'End' represents mass deployment planned completion month

Meter Base Repairs

PPL Electric is repairing meter bases in instances where the meter base conditions may not be conducive to safe meter exchanges. Approximately 10,721 meter base repairs were completed for exchange of a RF meter. Repairs to facilitate a meter exchange were conducted at a rate of approximately 0.8% of the premises where meters have been installed.

Progress on the End-to-End Solution

PPL Electric has delivered strong meter reading performance with its legacy PLC based AMI system. Meter read performance of the new RF based system is also performing at a very high level, exceeding the industry standard read rate of 99.5%.

Metric	Target	2017 Total	2018 Total	2019 Total	2020 Total*
Interval	**99.75%**	99.89%	99.82%	99.86%	99.97%
Billing Register	**99.75%**	99.90%	99.79%	99.86%	99.87%

** 2020 Results through July 31, 2020*

Customer Interaction

In accordance with the PPL Electric's approved Communications Plan, all customers were notified of pending meter replacements in several separate contact attempts. Each customer received a letter six weeks and three weeks prior to the meter exchange. Customers also received an automated phone call the day before their planned meter exchange. On the day of the installation, the installer knocked on the customer's door prior to the meter exchange. A door hanger was left at the premise at the conclusion of the visit.

PPL Electric has received 3,083 customer inquiries regarding the program out of 1,467,105 installations, or 0.21% of the installations. Some topics of these inquiries include:

- Questions regarding field work to be performed or completed
- Questions about scheduling an appointment for a meter exchange
- Statements regarding not wanting a new meter due to health and/or privacy concerns

There are currently zero pending customer inquiries.

Remote Connect / Remote Disconnect

Remotely connecting or disconnecting service (RCRD) went live on April 1, 2017. The matrix below outlines transaction success rate by process and overall.

RCRD Performance

		2017 Total	2018 Total	2019 Total	2020 Total *	Project To Date
Cut-Ins	Total Cut-Ins Attempts	8,833	33,798	39,544	1,128	83,303
	Total # of Successful Cut-Ins	8,618	33,473	39,416	1,124	82,631
	% Successful Cut-Ins	**97.6%**	**99.0%**	**99.7%**	**99.6%**	**99.2%**
Cut-Outs	Total Cut-Outs Attempts	11,222	43,809	53,005	1,966	110,002
	Total # of Successful Cut-Outs	11,013	43,239	52,830	1,964	109,046
	% Successful Cut-Outs	**98.1%**	**98.7%**	**99.7%**	**99.9%**	**99.1%**
Move-In	Total Move-In Attempts	10,475	48,725	62,834	28,346	150,380
	Total # of Successful Move-Ins	10,370	48,513	62,710	28,279	149,872
	% Successful Move-Ins	**99.0%**	**99.6%**	**99.8%**	**99.8%**	**99.7%**
Move-Out	Total Move-Out Attempts	8,312	38,355	48,236	24,351	119,254
	Total # of Successful Move-Outs	7,990	37,710	48,114	24,272	118,086
	% Successful Move-Outs	**96.1%**	**98.3%**	**99.7%**	**99.7%**	**99.0%**
Total	**Total Transactions**	**38,842**	**164,687**	**203,619**	**55,791**	**462,939**
	Total Successful Transactions	**37,991**	**162,935**	**203,070**	**55,639**	**459,635**
	% Successful Total Transactions	**97.8%**	**98.9%**	**99.7%**	**99.7%**	**99.3%**

** 2020 Results through August 9, 2020*

Financial Analysis / Cost Recovery

The financial analysis below shows actual costs per year and split between capital and operational and maintenance costs. This view shows the actual costs since project inception along with projections for future costs.

Actual Spend	**Capital**		**Expense**		**Total**	
12/31/2015	$	24,896,798	$	2,535,621	$	27,432,419
12/31/2016	$	70,874,632	$	2,426,326	$	73,300,958
12/31/2017	$	133,868,867	$	8,149,909	$	142,018,776
12/31/2018	$	118,216,208	$	8,346,431	$	126,562,639
12/31/2019	$	71,682,013	$	5,788,652	$	77,470,665
7/31/2020	$	19,511,026	$	3,760,059	$	23,271,085
Total Project to Date	$	439,049,544	$	31,006,998	$	470,056,542
Projected Spend						
8/1/2020-12/31/2020	$	4,548,974	$	-	$	4,548,974
Total Projected	$	4,548,974	$	-	$	4,548,974
Total Actual + Projected	$	443,598,518	$	31,006,998	$	474,605,516

Look Ahead

With only 40 meter installations pending to be completed, PPL Electric is in the process of completing stabilization and looking to conclude the plan by the of this year.

Conclusion

In summary, PPL Electric has followed its approved SMIP without the need for any material modifications. The RF meters installed, along with the scope, schedule, and cost of the program, are in direct alignment with the approved plan.

Attachment C

BUSINESS CASE COMPARISON: NATIONAL GRID VS RHODE ISLAND ENERGY

The purpose of this Attachment is to highlight the similarities and differences between the National Grid AMF Updated Business Case and the Rhode Island Energy AMF Business Case. Both plans recognized that the existing AMR metering fleet needs to be replaced because it is aging and incapable of enabling customer choice, grid modernization, and future functionalities required to enable achievement of Rhode Island's Climate Mandates.

There are many similarities between the two filings. Both organizations assume the same functionality from the AMF technology. From the network perspective, both Business Cases assumed a full-scale solution for Electric AMF using a similar technology for a fixed IT-based mesh communication system. The overall deployment period aligns between the two plans requiring 3½ years for AMF implementation. This includes an 18-month meter exchange period that is consistent between the two plans. Rhode Island Energy agrees with National Grid's alternative analysis that concludes "full-scale" is the only approach that will deliver the functionality that is needed. Rhode Island Energy also generally agrees with National Grid's alternative business analysis, with one exception, which is that Rhode Island Energy assumes that AMF deployment will utilize a combination of native and outsourced labor.

From the customer engagement perspective, both plans are implemented using a three-phase communication approach that utilizes messaging before, during and after the AMF meter exchange. The data latency commitment is similar between the two approaches, where customers will be able to see usage data within 30 to 45 minutes after a change in consumption. Both plans assumed that 1% of the customers would opt-out of having an AMF meter, health considerations for AMF are negligible as evidenced with similar and sufficient back-up. Both Business Cases also advocate the need for AMF infrastructure to implement Time Varying Rates ("TVR"), something that both committed to pursue in separate proceedings in the future.

While the basis and assumptions for the two comparative filings are much the same, the differences can be best summarized in five areas: 1) Rhode Island Energy took a broader recognition of the strategic importance of the AMF investment as an essential pre-requisite and enabling platform by designing a more hardened and robust communication network, 2) Rhode Island Energy quantified more operational efficiencies than their counterpart, having insight from PPL's AMF experience and confidence from business achievements, 3) Rhode Island Energy's operational integration and resulting business benefits occur faster due to system integration, business processes and tools that PPL has already developed and successfully implemented, 4) Rhode Island Energy included the additional cost of Pre-sweeps before the AMF meter deployment and is proposing to include the cost to repair meter bases when needed in the BCA to improve safety conditions, improve customer satisfaction, and bolster deployment efficiencies, and 5) Rhode Island Energy quantified two direct customer benefits that National Grid did not; the electric bill savings for customers who participate in Energy Insights and the value of automatic notification of outages from AMF over present-day manual notification.

For the communication network, Rhode Island Energy assumes its more robust AMF RF communication network will cover the Rhode Island Energy service territory in total, thereby avoiding the need- for cellular communications to augment meter reading capability of the RF meshed network. In addition to avoiding the need for cellular communication augmentation, Rhode Island Energy 's communication network design is sized for more data throughput than the National Grid's system which the Company believes will be critical for a future with more DERs, electric vehicles, clean energy, and to support AMF for gas customers.

A step was added in the deployment plan called "pre-sweeps" where safety and integrity of the current meter installation is examined before the exchange takes place. If meter base repairs are needed, Rhode Island Energy is taking responsibility to repair them. This step is incremental to the Rhode Island Energy Business Case and is based upon learnings from PPL AMF deployments. Because of PPL experience, several operational benefits were based on actual PPL experience rather than assumptions used in the National Grid Updated AMF Business Case.

In terms of when benefits will be realized (Benefits Realization), there is a striking difference between Rhode Island Energy and National Grid. PPL is bringing ADMS to Rhode Island customers as part of the Acquisition, making operational integration with AMF information available much sooner than anticipated in the National Grid Updated AMF Business Case. Because of this integration, which will be in development and completed before exchanging meters, incremental benefit realization can be achieved as each new AMF meter is installed. This contrasts with the National Grid Updated AMF Business Case in that the integration of AMF data with the ADMS operational data was scheduled to occur after Electric Meter Deployment. As a result, benefit realization for items such as outage notification, remote connect/disconnect, and operational efficiencies took place earlier for Rhode Island Energy and becomes significant because it impacts when value can be realized in the NPV calculations.

From the BCA perspective, both Business Cases were designed to be compliant with Docket 4600. In fact, Rhode Island Energy had the benefit of using and modifying the BCA that was initially prepared by National Grid. Assumptions were updated with the AESC 2021 report (rather than using the 2018 report), and other assumptions like total number of meters were updated when available. Because of the timing of systems integration Rhode Island Energy quantified the value of reduced time for outage notification using the ICE calculator. Both Business Cases used 1.5% energy savings from Energy Insights, although National Grid also included a "high" Energy Insights estimate of 3.5% which Rhode Island Energy did not. Rhode Island Energy estimated residential participation in Energy Insights at 30% of customers compared to 50%, which was estimated by National Grid. Bill savings that were realized by customers were quantified in the Rhode Island Energy case. For VVO, National Grid used 1% energy savings; Rhode Island Energy was more conservative by applying 0.5% energy savings for the VVO application. Both assumed complementary VVO benefits would apply in the Grid

Modernization filing. In terms of TVR, Rhode Island Energy took a conservative view with Opt-in assumption resulting in 20% participation for whole house and for EV. Rhode Island Energy also increased the expenses for TVR, knowing there would be additional software and integration required for implementation. National Grid calculated high and low values for both the Opt-In program and the Opt-Out program, resulting in four values for each benefit. Subsequently, National Grid averaged the four values for inclusion in the BCA.

Finally, two Direct Customer benefits that were not calculated by National Grid are included in Rhode Island Energy's BCA. These include the Electric Bill Savings for customers who participate in Energy Insights. Both National Grid and Rhode Island Energy calculated the energy cost savings associated with the 1.5% reduction in energy usage by participating customers. However, those customers will also see direct savings on their electric bill for all volumetric charges. Rhode Island Energy calculated the bill savings for those customers and, after deducting the Energy Savings already calculated, included the remainder as Customer Bill Savings.

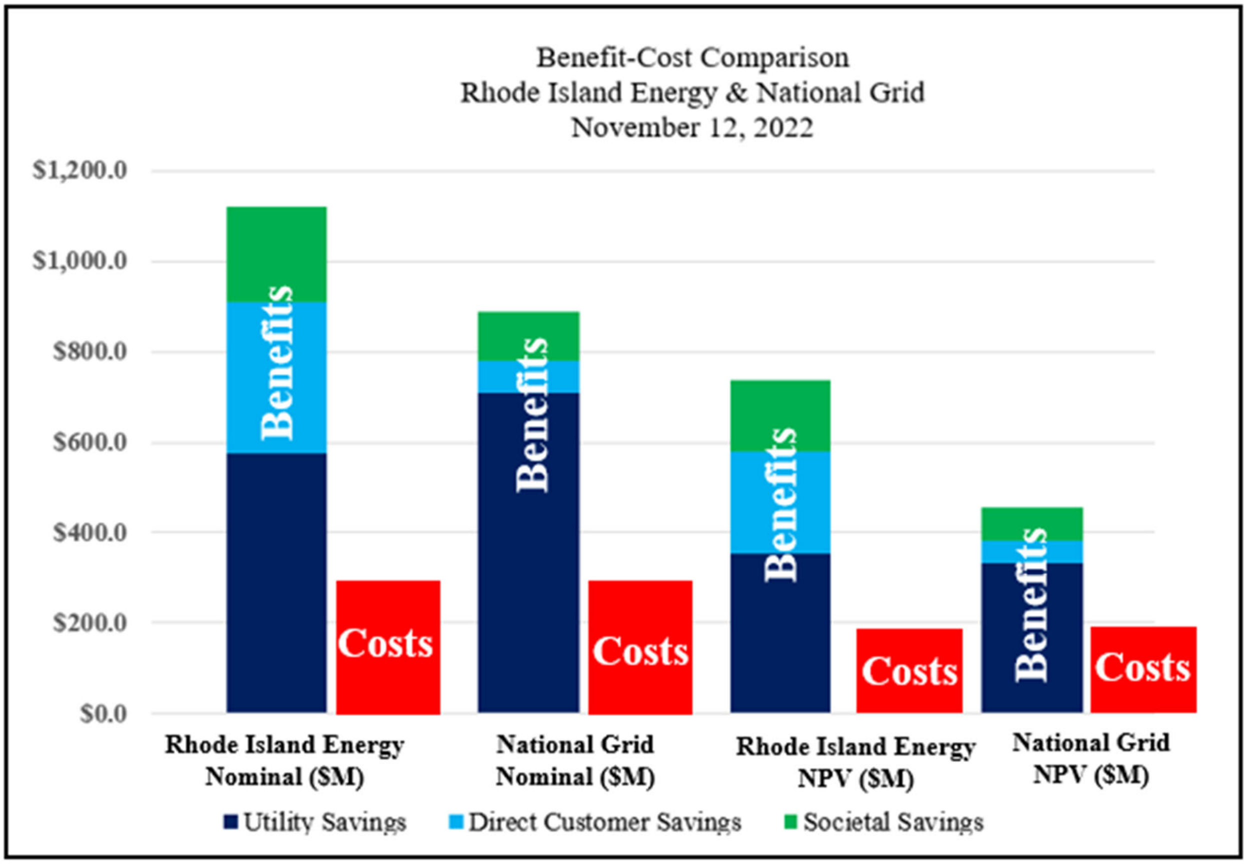
The second benefit in Direct Customer savings is the savings associated with the virtually instantaneous notification to the utility of a customer outage. Currently, Rhode Island Energy depends on customers to call in if their power is out. With AMF functionality, the meter itself sends a message as soon as the power is out. PPL's data shows that the difference between when the AMF meter automatically notifies the utility that the customer's power goes out versus when the customer calls in averages 22 minutes. When 22 minutes of reduced outage time is used in DOE's ICE calculator, it results in significant savings to customers. Rhode Island Energy included these savings in its Benefit Cost Analysis.

The benefits calculated by Rhode Island Energy result in better Benefit / Cost ratios than those calculated by National Grid in their filing of January, 2021. A 20-year nominal and Net Present Value ($2022 NPV) financial comparison of Rhode Island Energy's benefit-cost analysis ("BCA") to National Grid's BCA is summarized in the Figure C1 with a graphical depiction in Figure C2 below:

Figure C1: Rhode Island Energy and National Grid AMF Business Case Comparison

Rhode Island Energy and National Grid Benefit/Cost Comparison		
As of November 12, 2022		
Nominal ($M)	**RIE**	**NG**
Utility Savings	$ 529.7	$ 708.5
Customer Savings	$ 314.5	$ 70.8
Societal Savings	$ 215.1	$ 109.7
Total Savings	$ 1,059.3	$ 889.0
AMF Costs	$ 289.0	$ 289.4
Benefit/ Cost Ratio	3.7	3.1
NPV ($2022 M)	**RIE**	**NG**
Utility Savings	$ 354.7	$ 333.3
Customer Savings	$ 213.2	$ 48.5
Societal Savings	$ 161.2	$ 75.0
Total Savings	$ 729.2	$ 456.8
AMF Costs	$ 188.0	$ 192.6
Benefit/ Cost Ratio	3.9	2.4

Figure C2: Rhode Island Energy and National Grid: Benefit and Cost Chart



The bottom-line financial comparison is that the costs for the two plans are similar and the benefits for the Rhode Island Energy case are stronger and occur sooner. The result is a Benefit/Cost ratio on an NPV basis of 3.9 for Rhode Island Energy compared to 2.4 for National Grid. In reality, even after being conservative on the VVO and TVR benefit assumptions, Rhode Island Energy includes more functionality that is available earlier using a more robust communication system that is being executed by a deployment team that has experience implementing and operating AMF systems. Furthermore, with PPL's AMF experience there is increased confidence in the Rhode Island Energy Business Case due to having actual AMF business costs and benefits to base assumptions upon and due to having practical deployment experience, proven implementation models, and operational knowledge.

Attachment D

DETAILED DEPLOYMENT PLAN

1. AMF DEPLOYMENT OVERVIEW

The Rhode Island Energy Advanced Metering Functionality ("AMF") Deployment Plan outlines a preliminary overall strategy for deploying RF mesh network equipment and meter devices and provides the framework upon which more detailed Deployment planning documents will be developed.

Rhode Island Energy anticipates building out the AMF solution to provide cost efficiencies and strategic benefits to both Rhode Island Energy and its customers while creating a framework for advanced capabilities and future Smart Grid Modifications. To achieve these goals, the current AMR system will be replaced with an RF Mesh solution. This includes the replacement of all meters (approximately 524,677), installation of enhanced network equipment, and replacing AMF Systems to process the smart meter data.

The RF Mesh network enables remote communication with the meters and will include the following components:

Network Equipment	Description	Approximate Quantities
N2450 3-Radio High-Capacity Gateways	Primary data collection device including 3 radios with capability to transmit data back to the head-end systems utilizing various back-haul options	**109**
N2450 1-Radio Standard Capacity Gateways	Smaller data collection device including a single radio with capability to transmit data back to the head-end systems utilizing various back-haul options	**402**
Enhanced Mesh Routers	Device is utilized to close the RF mesh network gap by providing the critical 'hop' node through which meters can join the network mesh – mainly utilized in more remote areas	**1,280**
Fix-Up Antenna	Provides additional signal boost and extends the RF signal range for the meters located in less dense areas	**372**

2. DEPLOYMENT OVERVIEW & TIMELINES

2.1. Approach Overview

Rhode Island Energy will leverage PPL's experience with Advanced Metering infrastructure and utilize its knowledge with RF Mesh deployments to ensure the AMF deployment will be efficient, cost effective, and pave the way for strategic Grid Modernization investments in the future.

An example of a best practices approach will be the pre-sweep phase of deployment where, prior to meter exchanges, a crew will visit and capture meter and transformer configurations to build an optimized deployment schedule, allow for proactive identification of meter base issues, and schedule meter and base remediation before exchanges take place.

PPL also has a portfolio of application and business intelligence reporting enhancements that have been geared towards monitoring Advanced Metering rollouts, and which Rhode Island Energy can leverage to optimize its monitoring and reporting capabilities. These enhancements will be utilized to ensure the deployment schedule is met and the communications of the network are fine-tuned to the Rhode Island territory.

The initial focus of the Rhode Island deployment will be in developing a Network and Meter rollout strategy through a geographic construct defined as a Sector. The Sector is a planning construct from an operational point of view in this program and much of the focus will be to coordinate deployment to reach meter and network saturation in a target sector prior to moving to the next sector. There is an optimization process as well as a transition to operations process in place, which is also covered in detail through the Business Process Design Documentation.

In order to promote RF Mesh formation and stability in the network, both self-contained and transformer-rated meters are deployed in a target sector. The only exclusion may be considered for a subset of existing MV90 metered large power customers, where the AMF technology does not meet current business requirements. As per design, the RF Mesh coverage exists in a target sector as meters are deployed, hence RF mesh meters installed will provision and bring back consumption and interval billing data on the same-day through the head-end systems.

The designed network Gateway and Router deployment locations will be surveyed and proposed based on Rhode Island Energy-approved engineering standards. Furthermore, the Field Area Network designs will be reviewed and approved by the Rhode Island Energy Field Area Network and Engineering groups ahead of construction.

The network optimization and mitigation activities will occur concurrently as RF mesh meters are deployed to ensure all meters provision with the head-end systems. RF Mitigation devices such as antennas and Routers will be installed within a short time frame after deployment of meters to remediate RF-challenged communication devices as needed to meet read rate requirements.

2.2. Deployment Phases

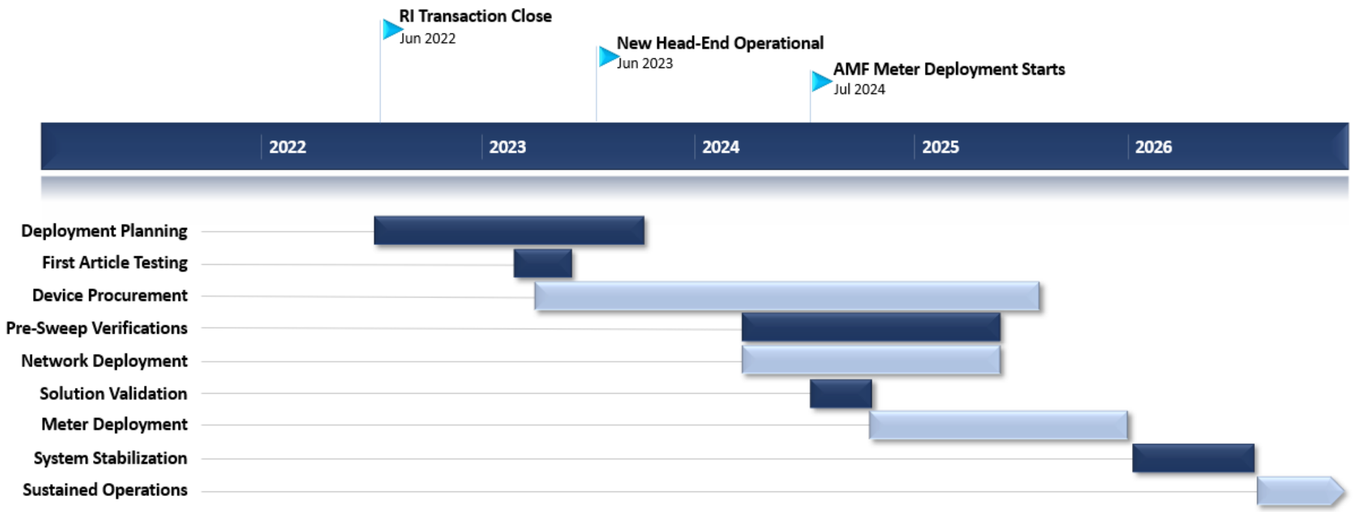
The following outlines the high-level deployment timeline planned for the Rhode Island AMF project and the activities planned during this time frame:

- **Deployment Planning** – The initial planning phase in which the Network and Meter roll-out schedule and deployment related activities are defined, and processes are developed.
- **First Article Testing –** During this phase, all devices will be tested to verify proper configuration for procurement and deployment.
- **Device Procurement** – During this phase the firmware and configurations are developed for all meter types and network devices and the procurement schedule is finalized.
- **Pre-Sweeps** – A pre-sweep of the meter population will include review of network configuration, accessibility, and replacement concerns for all meters within the territory.
- **Network Deployment –** In this phase the network devices are rolled out and RF mesh coverage is made available in order to deploy meters.
- **Solution Validation** – The initial deployment phase consists of approximately 500 RF mesh meters and the related network hardware. The IT systems, processes, and deployment activities are assessed, and necessary adjustments may be made prior to the Meter Deployment phase.
- **Meter Deployment** – During this phase the new AMF Meters are deployed in coordination with network hardware deployment to achieve same-day connectivity and provisioning.
- **Sector Acceptance** – The network vendor supports, maintains, and monitors meters, RF mesh network and systems prior to Sector Acceptance. After Meter Deployment reaches an agreed saturation point and Communications and Systems metrics are met, the ownership of network monitoring will be transitioned to Rhode Island Operations. The Network Deployment Vendor will continue to be responsible for the RF mesh network (break fix, drop-in read rates, etc.) until Final System Acceptance (which includes all sectors being complete).

- **Stabilization Period** – The phase in which systems and processes post sector deployment of meters are monitored and enhancements are implemented as required prior to Rhode Island AMF program completion.

- **Sustained Operations** – Phase in which operations and maintenance activities are transitioned to Rhode Island Energy for accepted sectors.

2.3. Program Roadmap



2.4. Program Milestones

Key deployment milestones and target timeline have been identified below.

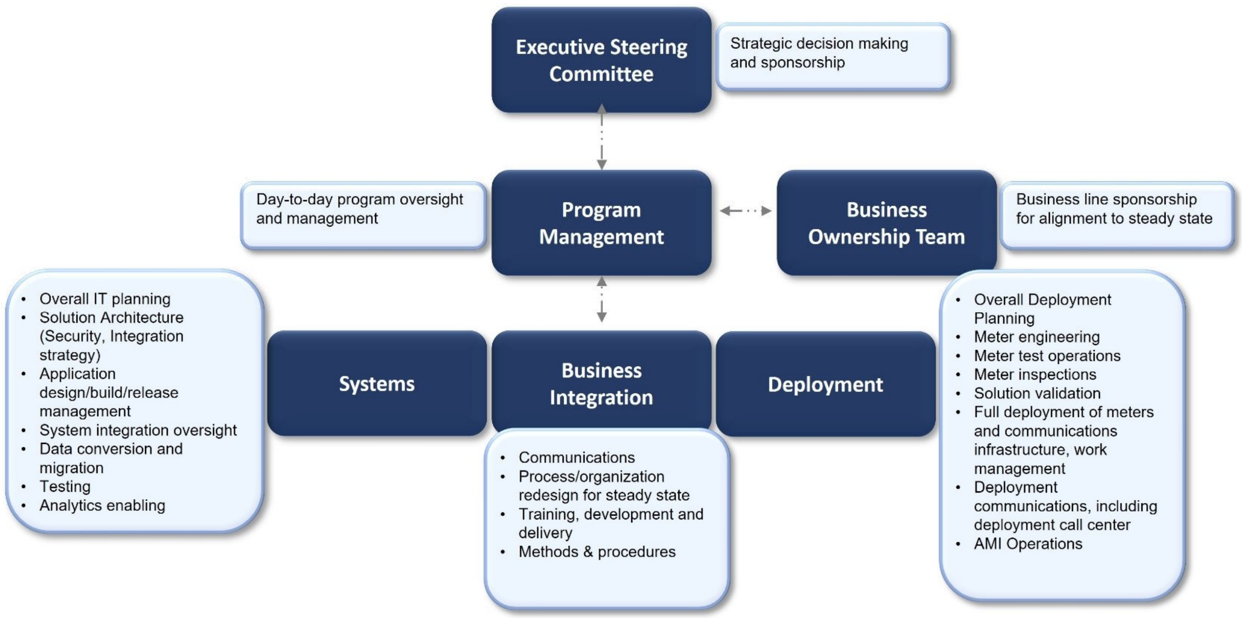
Deployment Milestones	Target Date
Meter First Article Acceptance Obtained (all forms)	August 2023
Pre-Sweep Connectivity Verifications Initiated	March 2024
Initial Gateway & Router Deployed in Field	March 2024
First Meter Deployed in Field	July 2024
Solution Validation Phase Complete	October 2024
Meter Deployment Target Completion	December 2025
Transition to Sustained Operations	June 2026

3. DEPLOYMENT STRATEGY

3.1. Governance

The Rhode Island AMF Deployment Program will require seamless coordination between a handful of functional groups, each with specific responsibilities to ensure the program's success.

3.1.1. <u>Governance Model</u>



3.1.1.1. Executive Steering Committee

The Executive Steering Committee is a strategic decision-making group and project sponsor. This committee's purpose is to provide overall governance and approval of all major policy, strategy, and financial decisions. Their ongoing responsibilities are to ensure organizational goals are aligned, necessary resources are assigned, and organizational issues are resolved to ensure successful project completion and execution.

3.1.1.2. Program Management (PMO)

The Program Management Office is the AMF project leadership team whose purpose is to plan and execute the project in its entirety, including day-to-day program oversight and management. They are responsible for the successful deployment of all infrastructure and implementation and/or migration of all IT systems. Expected outcomes include execution of all work activities such that expected deliverables are within scope, on time, and on budget, achievement of strategic and operational objectives, and the transitioning of all outstanding work items to ongoing operations upon project completion and closeout.

The project team will produce a multi-year roadmap, detailed project schedule, and performance scorecards incorporating all the strategies, actions, milestones, metrics, and responsible owners required for execution. The project team will be comprised of dedicated, full-time internal personnel from various utility functions integral to the project. It will also include subject matter experts external to the PMO that can provide ongoing support and/or provide specific and finite services and value. It will be led by the AMF Project Team Leader who is expected to champion the project vision, manage all resources and schedules including Workstream Teams, and be responsible for successful development of the overall project.

The Program Management Office will also manage all administrative functions of the project including but not limited to creating agendas, maintaining meeting minutes, tracking schedules and milestones, and monitoring how the project is progressing compared to the plan.

3.1.1.3. Business Ownership Team (BOT)

The Business Ownership Team are the line leaders representing ongoing operational functions within the organization. They are critical to the successful implementation of AMF in that they ensure the ongoing operating of the business during the deployment of meters, network, and systems infrastructure. These line leaders work collaboratively with the PMO and Workstream Teams to understand deployment activities and the impact they will have on operations, and consequently, prepare for and ensure business continuity and work to mitigate and/or eliminate customer impacts. This committee meets monthly and will include leadership representation from all departments impacted from the AMF deployment.

3.1.1.4. Workstream Teams

There will be three Workstream Teams including a Systems Team, a Business Integration Team, and a Deployment Team. They will represent the bulk of people assigned to the project as they carry out the primary day-to-day work activities of the project. These teams will be staffed with a variety of full-time, internal resources based on the skills needed to perform the work. The overall staffing will be based on the respective work volumes required. The teams shall be staffed with employees from Planning, Engineering, Operations, Customer, Information Technology, Legal, Regulatory, and Corporate Communications - as these represent the primary groups within the utility that possess the management skills, experience, process knowledge, and subject matter expertise to effectively execute the required work.

The Systems Team will incorporate work activities associated with planning, solution architecture, application design/build/release, system integration, data conversion and migration, testing, and analytics. The Business Integration Team will incorporate work activities associated with communication, process redesign, training development and delivery, and methods and procedures. The Deployment Team will incorporate work activities associated with planning, engineering, inspections, solution validation, full deployment of meter/communication network/methane sensors, work management, deployment communications, AMF operations, and meter testing operations.

Team leaders shall be appointed for each workstream team and will be key direct reports to the AMF Project Team Leader. RACI charts will be developed for the working teams to ensure roles, accountability, leadership, and communication are clearly defined and understood. Their core responsibilities include developing and executing the detailed workstream activities, managing scope in coordination with the PMO, tracking progress to plan and collaborating with each other.

3.1.2. Program Teams

- **Project Deployment Team –** Includes Program Management, Deployment and Business Integration teams supporting the project oversight, monitoring and review of program metrics and vendor management.
- **Network Deployment Vendor –** Responsible for deployment of RF Mesh Network Devices, Configuration, and Optimization of the Network, as well as the Network Communications and a portion of the Systems Technology supporting the RF Mesh design. The Network Deployment Vendor will also be responsible for identification and management of the Field Installation Vendor.
- **Field Installation Vendor –** Deployment team responsible for Meter Exchanges; will report directly to the Network Deployment Vendor with oversight from the Project Deployment Team.
- **Advanced Metering Operations (AMO) –** Rhode Island Energy Operations Team supporting the AMF Network Monitoring, Reporting, and Incident Resolution. The AMO will also interface with RIE Customer Care teams to support customer facing issues.
- **System IT Team -** Will include several IT teams between Rhode Island Energy IT and vendors to support system integration of the RF Mesh Network, Metering, Customer, and Operations systems.

3.2. Deployment Planning

Deployment Planning is the initial phase of the Deployment lifecycle.
Activities include:

- Sector Identification and Geographical Considerations
- Development of the Deployment Schedule
- Finalizing Detailed Communication Plans
- Deployment Safety Planning

The following sections describes the planned approach to complete each activity.

3.2.1. Sector Identification and Geographical Considerations

Sector identification is key to ensuring success for all phases of deployment. The following factors are considered when determining sector sizes and geographical boundaries:

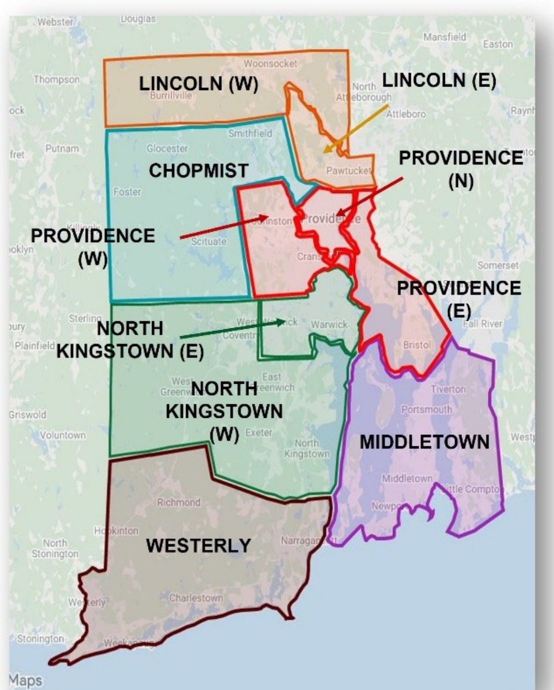
- **Existing Municipalities and Operating Areas** – All sectors follow municipal town boundaries within Rhode Island, which also serve as utility operating areas.
- **Quantity of meters per sector** – Each sector has a target quantity of 40,000 to 60,000 meters. With an average meter exchange rate of 10,000 meters per week, this sector size provides a reasonable timeframe for completing deployment activities necessary for sector acceptance.
- **Congested Areas –** Coastal areas in Rhode Island experience periodic seasons of high traffic, primarily in the summer. To prevent delays, meter exchanges will not be scheduled in sectors along the coastline during these times of heavy congestion.
- **Condition and Age of Equipment –** The deployment schedule attempts to prioritize areas where older, deteriorated, or corroded equipment is of greater concern, and where more time may be needed for repairs or replacements.
- **Service Type Diversity –** Each sector has varying quantities of service types and sizes. The deployment schedule favors sectors with less diversity during the initial stages of deployment to focus on solution validation prior to entering areas with larger and potentially more complex services.
- **Billing Cycles/Route IDs –** Each sector includes multiple billing cycles to account for days surrounding bill dates, or blackout days, when meters cannot be exchanged.

- **Rural and Urban Areas –** Both rural and urban areas present unique challenges. For example, although rural areas may have fewer quantities of meters installed indoors, more network equipment may be needed to establish reliable communication. Conversely, urban areas may have high concentrations of meters installed in one area, but there may be more indoor meters requiring appointments. In addition, some urban areas may be less secure and require more than one installer. A more rural sector is preferred at the beginning of the project to establish good procedures before entering the more densely populated areas.

- **Distributed Energy Resources –** To support grid modernization efforts and systems analysis, sectors with higher quantities of Distributed Energy Resources, or DERs, are prioritized to better leverage the AMF investment and gain a more comprehensive load perspective in the early stages of deployment.

3.2.1.1. Meter Population by Operating Area

Currently, Rhode Island utilizes six operating areas which include 38 municipalities or towns. Meter counts within these operating areas range from 38,000 to 178,000 meters.

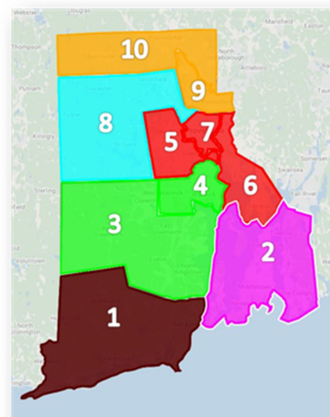


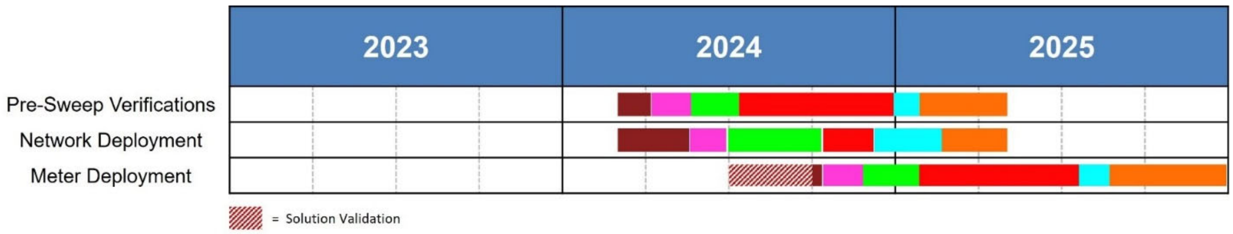
Operating Area	Meter Quantity
Westerly	54,530
Middletown	51,112
North Kingstown	100,748
Providence	178,647
Chopmist	38,740
Lincoln	100,900
Total Meters	**524,677**

3.2.1.2. Meter Deployment Sequence by Sector

Within each operating area there are a variable number of sectors defined. Sectors are broken up within an operating area based on volume of customers and geographic significance. Although the sector construct is important for acceptance purposes, it is equally important from the stakeholder engagement and operations perspectives. Sectors are constructed to include a target range of 40,000 – 60,000 meters.

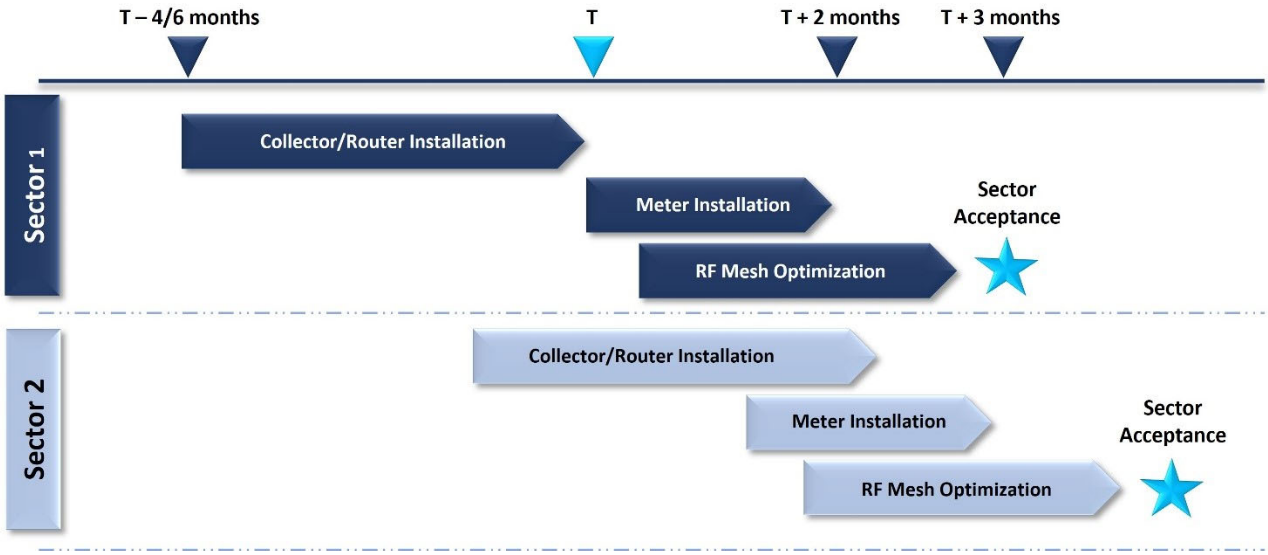
Sequence No.	Sector	Towns	Meter Quantity
1	Westerly	Charlestown, Hopkinton, Narragansett, Richmond, South Kingstown, Westerly	54,530
2	Middletown	Jamestown, Little Compton, Middletown, Newport, Portsmouth, Tiverton	51,112
3	North Kingstown - W	Coventry, East Greenwich, Exeter, North Kingstown, West Greenwich	43,587
4	North Kingstown - E	Warwick, West Warwick	57,161
5	Providence -W	Cranston, Johnston	51,326
6	Providence - E	Barrington, Bristol, East Providence, Warren	47,488
7	Providence	Providence	79,833
8	Chopmist	Foster, Glocester, North Providence, Scituate, Smithfield	38,740
9	Lincoln - E	Central Falls, Lincoln, Pawtucket	55,252
10	Lincoln - W	Burrillville, Cumberland, North Smithfield, Woonsocket	45,648
		Total Meters	**524,677**





3.2.1.3. Rolling Sector Schedule

The following illustration provides a high-level depiction of various deployment and optimization activities and an approximate timeline of events. Pre-Sweep verifications, Network Deployment, Meter Deployment, and optimization activities across various sectors are discussed in further detail in following sections. Deployment activities will occur concurrently across multiple sectors as depicted below.



3.2.2. Development of the Deployment Schedule

3.2.2.1. Scheduling Process

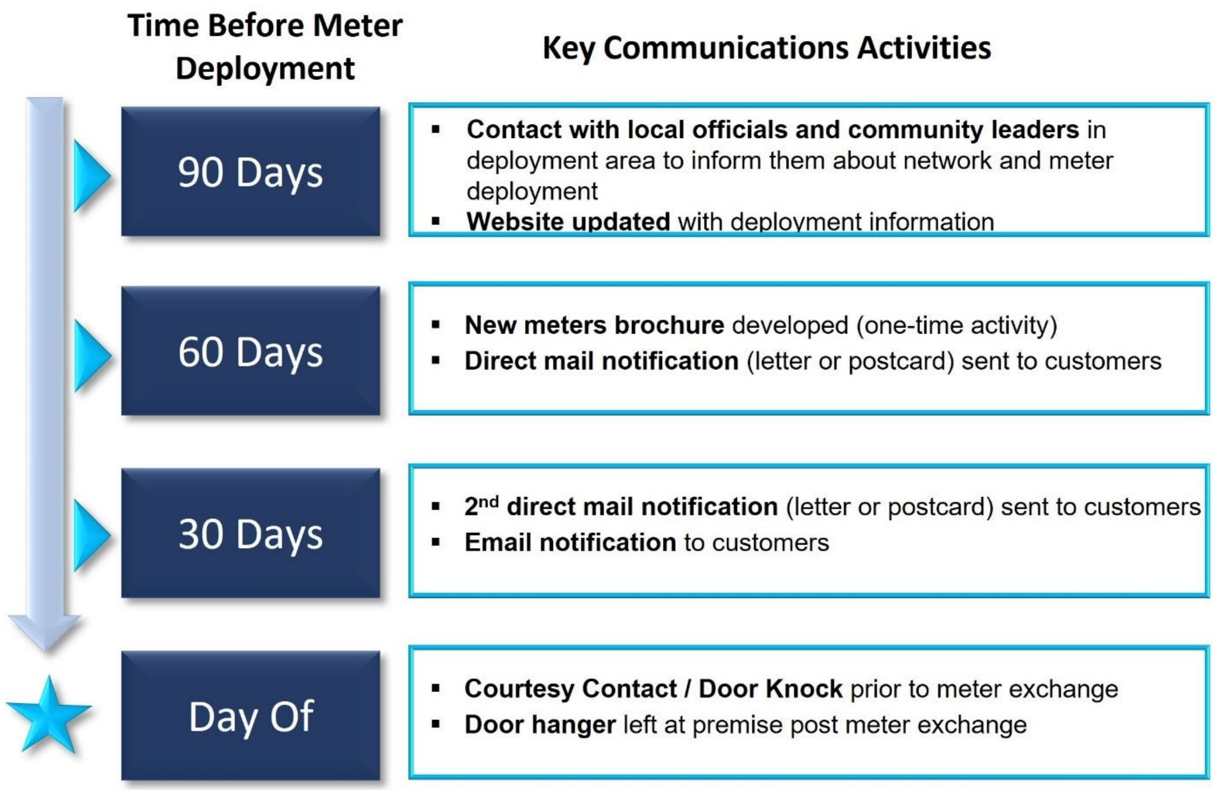
The detailed deployment schedule is developed by the Network Deployment Vendor in collaboration with the Field Installation Vendor. There are a number of considerations while developing the deployment schedule some of which are discussed earlier in the overall meter deployment approach section.

The detailed daily work schedule will be created and managed by the Network Deployment Vendor with supervision and monitoring conducted by the Project Deployment Team. The actual dispatching of work in the field will be conducted by the Field Installation Vendor in coordination with the Network Deployment Vendor. The deployment schedule will be reviewed and approved by the Project Deployment Team.

3.2.3. Communications Plan

3.2.3.1. Customer Notification Process

There will be multiple communication points with external stakeholders and customers prior to deployment of RF mesh meters. The current plan for customer and stakeholder engagement is illustrated below.



3.2.3.2. Municipal Communications

As part of the overall communication plan, Rhode Island Energy has decided to engage local and municipal authorities in advance of the meter and network roll-out in each community. This would allow insight and better prepare authorities to address customer and constituent inquiries ahead of the roll-out.

3.2.3.3. General Customer Communications

The targeted customer communication will commence approximately 60 days ahead of meter roll-out in a sector. The initial communication material will be educational and provide a high-level summary of the exchange process and benefits of the program. This communication will also point the customer to the Rhode Island Energy website for additional information. The second wave of communication will follow within 30 days of roll-out and include specific details regarding installation timelines. Email communication may be utilized for larger C&I customers as appropriate.

Furthermore, customized door hangers will be also utilized for missed-appointments, physical obstructions found at premise, property damage during installation, and scheduled repairs where premise is visited post initial visit.

All customer communication material will reference appropriate contact / call-back information for the AMF Installation Vendor Call Center. As a result, there is limited volume expected to be directed to the Rhode Island Energy Customer Care Call Center.

Initial sector communications may require a scaled back communications plan. However, any variation from the plan requirements requires approval from the Rhode Island Energy Project Deployment team.

3.2.3.4. Large Power Customer Communications

At Rhode Island Energy, large power customers are classified based on a usage capacity figure derived from the 5 highest peak days defined as Installed Capacity (ICAP). Any account with an ICAP value greater than 100 would be considered a large power user. Only a handful of accounts have a representative / manager assigned to them (approx. 1600 accounts), and special notification will be provided to these customer representatives prior to meter roll-out.

It was determined that vast majority of these customers do not require any special notification process as part of meter deployment, but any interruptions in service will require prior notification and appointments scheduled.

As part of the meter deployment process, the Key Account Managers will be notified by the deployment team for awareness purposes, and to support with coordination activities as required. All customer notifications will also be documented as account notes in CSS in case the Rhode Island Energy Call Center is contacted in regard to the RF mesh meter roll-out.

The notification process for large power customers will be similar for the most part to all other customers with exceptions around special accounts requiring appointment or disconnect. (e.g., KYZ pulse, Form 9S meters, 480V service, etc.)

3.2.3.5. Internal Stakeholder Communication

The Rhode Island AMF project will communicate and engage with a variety of internal stakeholder groups. Communication efforts will be tailored to meet each group's distinct informational needs. Internal stakeholder groups include:

Stakeholder Group	Description
Rhode Island Energy Executives	Members of the Rhode Island AMF executive steering committee
Business Ownership Team (BOT)	Members of the Rhode Island AMF Business Ownership Team consisting of leaders from key impacted departments across Rhode Island Energy
Rhode Island AMF Project Team	Rhode Island AMF project team members and part time SMEs
Corporate Communications	Corporate Communications employees
Rhode Island Energy Customer Service Employees	Customer Service employees, including the following subgroups: Advanced Metering and Data Operations, Billing, Customer Care (CCC), Customer Communications, Customer Operations and Business Improvement, Energy Efficiency, Major Accounts, Marketing Research, Regional Operations, Regulatory Programs, Revenue Assurance
Rhode Island Energy Distribution Operations Employees	Distribution Operations employees, including the following subgroups: Distribution Engineering, Regional Field Operations, Respond to Customer
Rhode Island Energy Finance and Regulatory Affairs Employees	Finance and Regulatory Affairs employees, including the following subgroups: Regulatory Affairs, Load Analysis, Supplier Coordination
Rhode Island Energy IT Employees	IT employees, including the following subgroups: Business Intelligence, Customer Service System, Distribution Ops Systems, Enterprise Architecture, Infrastructure, Metering Systems, Security, Self-Service/ Web Development, Transmission Ops Systems, Work and Asset Management
Rhode Island Energy Technical Development and Improvement (TDI) Employees	TD&I employees, including the following subgroups: Emergency Preparedness, Technical Development and Communications, Training
Other Rhode Island Energy Employees	All other Rhode Island Energy employees

Internal communications activities are grouped into three categories or 'campaigns' based on the key messages that are communicated throughout the project life cycle.

The three communications campaigns are:

1. **Awareness Communications** – Communications sent to create a general understanding of the project scope, objectives and benefits. Awareness messaging occurs at the beginning of the project.

2. **Ongoing Communications** – Communications that occur on a regularly scheduled basis to ensure key stakeholders are kept informed of project status. Project update communications start at the beginning of the project once a general awareness of the project has been established and continue throughout the duration of project.

3. **Project Release Specific Communications** – Communications sent to inform, educate, engage, and prepare Rhode Island Energy employees for the changes associated with an individual release. Release-specific messaging occurs before, during, and after each of six major project releases.

As part of the deployment process, internal stakeholders are engaged 2-3 months ahead of network site survey activities and roll-out of the Gateways. The communication will focus on Operating Areas and Regions to align with Rhode Island Energy organizational operating territory.

Further details on the communication plan can be found in the Rhode Island AMF Master Communication Plan document.

3.2.3.6. External Communications

As part of the AMF project, Rhode Island Energy has developed a communications plan for educating and engaging external stakeholders including customers, community leaders, Commission staff and members of public advocacy groups. This section describes the key messages to be communicated and communications activities to be executed throughout the duration of the project. The Rhode Island AMF project will utilize a variety of channels throughout the project to communicate with different external stakeholder groups.

3.2.3.7. AMF Installation Vendor Call Center

As discussed previously, the customer communication material will reference the AMF installation vendor call center contact information to reduce the incoming contacts to the Rhode Island Energy Call Center. The following are some of the requirements outlined for the AMF Installation Vendor Call Center:

- The call center must answer calls within the threshold of an agreed upon SLA for abandoned calls per month
- Call back customers who have left messages by no later than the next working day
- Provide multi-lingual Call Center services in English and Spanish
- Provide Call Center services from 8AM-8PM Eastern, Monday-Friday and Saturday 8am – 4pm
- Provide after-hours call back service
- Provide representatives with access to real-time field data regarding the Meter exchange
- Provide a record of all communications between AMF Provider and customers
- Provide customers with appropriate emergency response information
- Conduct periodic customer satisfaction surveys regarding the communications between the customer and the call center
- Provide a customer feedback system that captures customer compliments, complaints, and suggestions, and that implements a process to address each.
- Make the following data available on an ad-hoc, 30 min interval, daily, month-to-date, month-end, year-to-date, and cumulative basis to support call center reporting:
    - Total calls
    - Average Speed of Answer (ASA)
    - Wait time
    - Total and average call handle time
    - Total and average talk time
    - Total and average after call work time
    - Total and average hold time

  - Total and average unavailable time (paid non-break time)
  - Calls per representative
  - Calls per thirty (30) minute interval
  - Calls per day
  - Calls per month
  - Abandoned/lost calls
  - Total number and percent of calls blocked or busy calls
  - Telephone Service Level (TSF) daily, weekly, monthly, quarterly
  - Calls transferred to The Company
  - Short calls (<10 seconds)
- Set-up and establish call center in operational condition prior to the installation of the first AMF meter
- Provide a dedicated toll-free line for the handling of inbound calls

3.2.3.8. Customer Opt-Out

All customers, either residential or commercial, will have the option to decline, or opt out of, having a AMF meter installed. These opt-out requests can be received at any time, including the day of a scheduled meter exchange. Customers will be informed of this option through advance mail or email notifications in the days leading up to the meter exchange. These notifications will provide timeframes for meter exchanges as well as instructions for declining the exchange.

Customers who choose to opt out of having an AMF meter installed will be required to notify the utility, at which time a utility representative will seek to address any concerns regarding safety or privacy, provide information regarding benefits, and inform them of the consequential rate impacts going forward, which will include a monthly manual meter reading fee. Although AMF enhances the customer experience through energy management and usage perspectives, it is assumed that a 1% subset of the customer base will choose to opt out.

3.2.4. Deployment Safety Plan

The installation vendor project resources operate with recognition that safety, health, and welfare of their employees are always of primary importance. The success of the safety plan will depend on every employee understanding and implementing this plan and adhering to the overarching Rhode Island Energy safety standards and protocols. It is the responsibility of the entire team "to do all that is practical to prevent accidents by ensuring a common understanding of risks and how to control them through the organizational structure."

All installation vendor employees are mandated to always adhere to the corporate safety programs. The field deployment vendor will be responsible to create a Safety Program for its personnel.

The following sections will summarize at high level some key aspects of safety regarding deployment on the Rhode Island AMF program.

3.2.4.1. Safety Training

The field installation vendor will conduct training as required for all vendor employees and new employees will be trained prior to being assigned work. This training will be coordinated by the field installation vendor, but all material and messaging will be reviewed and approved by Rhode Island Energy. Training will include familiarizing new employees with applicable safe work practices. An employee who has not performed a task for an extended period may need re-training. Supervision will determine if the employee understands the safe work practices associated with the task. If re-training is required, the training will include familiarizing the employee with applicable safe work practices.

Training is required whenever a new process, procedure, or equipment is introduced into the workplace. The training will ensure that employees understand any safe work practices associated with the new processes, procedures, or equipment. The supervisor will document the training and keep a record on file at the work location. Training is required whenever a new potential hazard is discovered. Training will ensure that employees understand the safe work practices associated with the new potential hazard. This training will be documented by the supervisor and kept on file at the work location. Supervision will also be trained to recognize potential hazards. This training will ensure that supervision is familiar with all safe work practices associated with the work of their employees.

The field deployment vendor provides its meter technicians a minimum of 2 to 3 weeks of training that consists of:

1. Classroom training highlighting all safety and operational policies of the job as well as simulated meter exchanges on live electric meter training boards.

2. Field training performing meter exchanges while accompanied by experienced Field Trainers to confirm a thorough understanding of all safety and operational procedures.

3. After demonstrating a thorough understanding of all safety and operational procedures, the meter technician is released for unsupervised installations. Meter technicians are then subject to post and in-process inspections performed by the local crew lead.

4. Rhode Island Energy shall ensure periodic audits are conducted to guarantee compliance with safety and procedural guidelines.

3.2.4.2. Safety Roles and Responsibilities

The following are safety governance roles to be supported by the field installation vendor.

Operations Directors – The Operations Director is responsible for the implementation of the Safety Plan within their regions. This responsibility includes holding their organization accountable for their performance of this procedure. Operations Directors are responsible for observing a minimum of two crews per month.

Project Managers – Project Managers are responsible for holding Supervisors accountable for their performance of this procedure. They are responsible for observing a minimum of four crews under their jurisdiction per month.

Supervisors – Supervisors are responsible for observing a minimum of 2 crews per week, and 100% of their assigned crews every quarter.

Regional Safety Manager – The Safety Manager will serve in the capacity of advisor to the line organization for the Job Behavior Observations (JBO) procedure. The Safety Manager (or alternate as designated by the Operations Director) will compile and analyze data and information monthly.

3.2.4.3. Safety Management Procedures

Job Behavior Observations

- Crew Job Behavior Observations will be performed as detailed above as part of the routine conduct of business. The following steps shall be followed in the performance of a JBO:
  - Supervisor will schedule the JBO
  - Observe the crewmembers as they perform their work
  - Talk with the workers about your observations. Question them about safety knowledge, concerns, etc.
  - Findings are documented
  - Follow-up meeting will be scheduled as needed
- JBO's will be entered into the JBO database provided by the field installation vendor each week (timely input is extremely important).
- The Safety Manager will collect, summarize, and report the prior month's performance to the Operations Director. The report will also include a calculation of performance metrics, which include the number, and percent of safe vs unsafe observations.
- The Operations Director will communicate to the region those detailed findings from the prior month along with management direction to address identified issues.
- Safety Specialists will periodically audit the supervisors' JBO quality and accuracy by conducting a ride along, duplicate JBO on those same crews. The two JBO's will be reviewed and compared, with the Safety Specialist providing feedback on the supervisors' observation techniques.

Job Briefings/Tailboards

Conducting a thorough job briefing that identifies workplace hazards is critical to working safely. It is important to conduct multiple job briefings if changes in the nature of the work could jeopardize an employee's safety.

The Job Briefing is an important tool to help you recognize and avoid hazards, and to protect yourself from injury. But it will only be effective if you use it. The value is not in filling out a form, but it's in the practice you go through to train yourself to be observant, to plan and take action to protect yourself from injury. You are responsible for your own safety.

All injuries are preventable and working safely is a condition of employment in accordance with the deployment vendor policies.

Incident Reporting

It is each employee's responsibility to report any injury, illness or accident, no matter how slight, to his or her supervisor immediately following occurrence. First Aid shall be administered promptly. If additional treatment is necessary, the injured employee should be transported to the nearest medical facility or physician. If the preliminary investigation reveals that an employee's action or inaction may have caused or contributed to the event, supervision shall arrange for post-accident testing to occur.

When notified, the supervisor will collect evidence from the accident site including taking photographs and measurements, securing damaged parts or equipment, or barricading the area if necessary. The supervisor is to ensure immediate notification to all appropriate individuals per the following guidelines.

In emergency situations, the installation vendor will immediately contact Rhode Island Energy or the assigned representative within the deployment team to report the situation. Rhode Island Energy reserves the right to request a stand-down in critical emergency situations and the installation vendor will cease performing deployment activities at the discretion of Rhode Island Energy in such situations.

Root Cause Reporting & Lessons Learned

After Incident Reporting has been provided a follow-up Root Cause Investigation shall be performed within 5 days following the incident. Root Cause Investigation reporting will provide an analysis of why the event occurred and remedial actions being taken to eliminate or minimize the probability of a similar occurrence from happening again.

3.3. Device Procurement, Testing and Acceptance

There are several stages during which meters and network devices are tested to ensure compliance to Rhode Island Energy requirements.

3.3.1. First Article Testing

As a primary method for the inspection and testing of vendor meter and network components, the First Article Tests (FAT) will determine if the devices meet Rhode Island Energy acceptance requirements (firmware, configuration, functionality, faceplate, etc.), safety and quality control requirements. FAT must be conducted, and results approved, before the manufacturer starts full production manufacturing or makes any changes (e.g. firmware upgrades). The FAT will be conducted at a Meter Testing Facility where devices will be shipped from the Network Deployment Vendor directly to this location to conduct the testing.

Upon acceptance of FAT results, the vendor will further conduct production testing and lot sample testing during the manufacturing process.

Within the Rhode Island AMF Program, the following are key objectives of First Article Testing:

- The ability to First Article Test meters that will be utilized within the Rhode Island AMF program for both current and future release capabilities
- The ability to First Article Test different forms and configurations of meters
- The ability to utilize the First Article process for RF mesh meters – one process with a number of off-ramps for different types or categories of meters
- Standardization, such that, when a secondary meter vendor is introduced as a supplier to the Rhode Island AMF program, their meter products will also be able to follow the Rhode Island Energy First Article Process
- Leverage AMF meter Rhode Island Energy First Article Testing Processes – Utilize best practices from previous testing cycles
- Consistent documentation and results archived appropriately

3.3.2. Shipment Sample Testing

Shipment Sample testing will be conducted at a Meter Testing Facility for a representative population from every shipment received at the installation vendor cross-docks. The cross-docks are satellite offices set up throughout the deployment phase in active regions to facilitate material storage and distribution. Multiple cross-docks will be set up across the Rhode Island territory throughout the deployment phase by the field installation vendor. All meter shipments are received by the installation vendor at the cross-docks directly from the technology manufacturer, and representative samples are then removed from the shipment and shipped to a Meter Testing

Facility for Sample Testing purposes. This activity is coordinated by the field installation vendor.

While meters are being tested at the Meter Testing Facility, the remaining shipment will be in quarantine by the installation vendor at the cross dock awaiting approval of the Sample Test provided by Rhode Island Energy.

The sample size for this testing process will be dependent on shipment volumes. The shipment quantity of complex meter forms is typically smaller and as such, fewer meters will be randomly selected for Sample Testing.

Test samples will be selected by the Rhode Island Energy meter shop and will be randomly chosen from the entire shipment. In instances where meters are packaged with multiple devices in a box, contiguous meter IDs from a single box will be selected. For instance, if 200 meters are required for a test and meters are packaged four to a box, fifty random boxes will be selected for testing.

While meters are being tested at the Meter Testing Facility, the remaining shipment will be in quarantine awaiting approval of the Sample Test. Sample testing will use pass / fail criteria from ANSI/ASQ Z1.9 to achieve an AQL of 0.25%. Meters will undergo both functional and accuracy testing. Failing either test will result in rejection of a delivery.

3.3.3. Removed Meter and Selective/Sample Accuracy Testing Strategy

Rhode Island Energy has a comprehensive testing strategy to support all watthour and demand meter testing as part of business-as-usual service. As Rhode Island Energy will be replacing all meters as part of the AMF Deployment program, Rhode Island Energy will be requesting waivers to the following regulatory testing categories: 1) "Removed from Service Meter Testing", and 2) "Selective/Sample Accuracy Testing" for the entirety of the 18-month deployment window.

All other removed legacy AMR meters will be stored for a 60-day period, upon which they will be scrapped and a certificate of salvage will be provided by the field installation vendor to Rhode Island Energy.

3.3.4. Meter Installation Ancillary Equipment

A variety of accessories may be needed for meter installation. These include seals, replacement rings, locking rings, jumpers, plates, and other devices. These devices are provided by Rhode Island Energy but must be ordered in a timely manner by the meter installer. Any expediting costs incurred by Rhode Island Energy due to lack of planning by the Field Installation Vendor will be passed back to the vendor.

3.3.5. Meter and Network Device Procurement/Forecast

The Network Deployment Vendor is responsible to provide monthly meter and router purchase forecasts to support their own installation plans. Rhode Island Energy will advise of additional meter purchases needed for its own needs. The forecast will anticipate stocking area operating centers (truck and warehouse stock) to support turnover of sector operations upon sector acceptance.

The forecast will include alternate meter supplier purchases. The use of alternate supplier meters must be spread across all sectors starting from the Solution Validation Phase (based on percentage of meters allocated for the alternate meter supplier). The first sector may be excluded from this requirement.

3.4. Pre-Sweeps

Pre-sweeps are performed as a pre-deployment activity to verify site records and identify potential risk factors prior to meter deployment. Pre-sweep reviews will begin before initial meter installations and will follow the same sector sequence identified for full deployment.
A dedicated vendor will be selected and utilized for the Pre-sweeps and will be responsible for capturing site information pertaining to each meter, which include, but are not limited to the following:

- Locations and Service addresses
- Transformer associations
- Accessibility
- Service types and sizes
- Condition of associated equipment
- Tampering/Energy diversion scenarios
- Repair candidates
- Stranded assets (meters or transformers)

- Safety concerns
- Photos of the meter configuration:
  - Meter base
  - Meter
  - Point of attachment
  - Premise

Regularly scheduled file transfer processes, including photos, between the vendor and the utility will ensure that both parties always have current, up-to-date information. This saves time for the vendor and allows the utility to quickly respond to and remediate issues in preparation for full meter deployment.

A sample of the Pre-sweep checklist in its entirety can be found in Appendix section 4.2

3.5. Device Deployment

The AMF deployment activities will consist of RF mesh network device deployment followed by AMF mesh meter deployment. In the following sections the overall approach for deployment of these devices has been discussed.

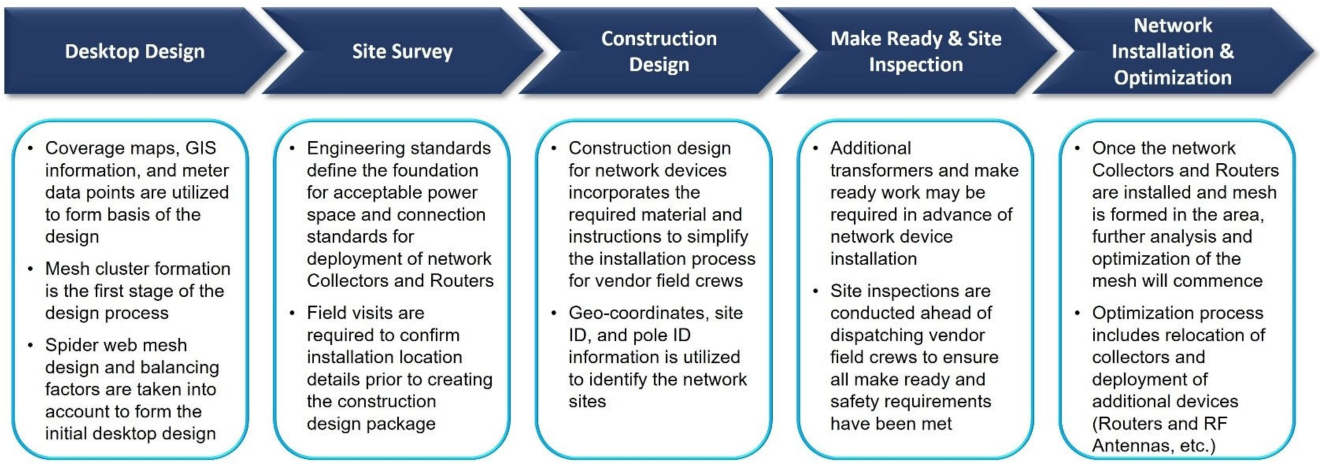
3.5.1. Network Deployment

3.5.1.1. Overall Network Deployment Methodology & Approach

Network Deployment's overall direction is to design, build and deploy a robust field network infrastructure that optimizes a consistent high level of performance and low operational costs. The following stages comprise the high-level tasks of Network Deployment:

- Network RF Mesh Desktop Design
- Gateway & Router Site Survey
- Construction / Engineering Design Package Creation
- Network Gateway & Router Deployment
- Deployment of Meters

- Optimization and Sector Acceptance



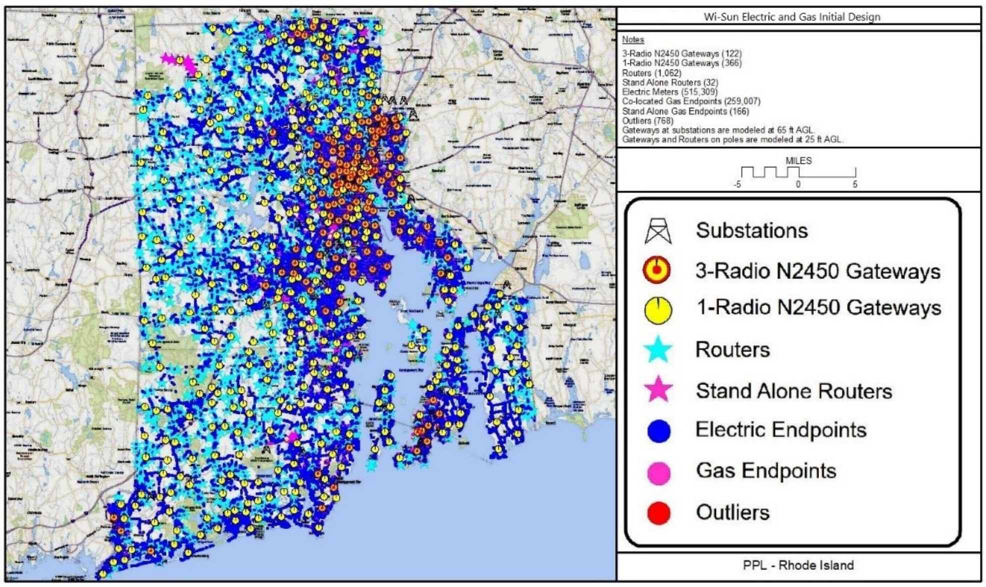
3.5.1.2. Network RF Mesh Design

Network Design consists of the steps and decisions made for initial Gateway and Router placement, taking into account terrain (topography and topology) and meter placement. There are important considerations around substations, pole and transformer locations that feed into the design process.

The design is a multi-step process starting with identification and creation of buffer zone and clusters. The size of the buffer is dependent on the probable local radio frequency strength and related topographical distance. Dense urban and forested areas typically result in smaller buffers than rural, suburban, and level topographical areas. When creating these buffer zones, other location factors must be considered such as whether the meter is housed above or below ground, or outside or inside a customer's premise.

Meter clusters are created by drawing buffers around individual meters and grouping meters together, creating a cluster of overlapping meter buffers. The communication distance parameters are analyzed for each meter and the appropriate buffer size is applied to the network design. Clusters are formed when these meter RF buffers overlap, becoming more prominent in areas with dense customer populations. During the detailed design phase, the size of these "clusters" needs to be evaluated and optimized.

The initial design completed by the Network Deployment Vendor is based on overall meter density clusters, and further meter geo-coordinate location details will be required in the subsequent stage to conduct a detailed analysis. The detailed design will be critical in planning the meter roll-out in that closer attention will be focused on optimization in areas where the RF mesh network is determined to be weaker in the design (low density and high hop count areas).



Once the cluster is determined to be large enough to fully utilize a Gateway, a network mesh is created to determine an acceptable parent for each meter within that cluster. These linkages approximate a "best guess" of actual mesh formation. Many other factors come into play when a deployed meter selects its communication path, however, these parameters are difficult to simulate when considering millions of meters. From an RF Design perspective, the topographical distance between end points is the best determinant for an evenly balanced cluster utilizing a minimal number of "hops" in all directions. The design also aims to achieve an equal number of meters under each Gateway's area if multiple network devices are deployed in a cluster. In the Rhode Island RF Mesh design, the Gateways will be designed to achieve a relatively flat mesh to provide coverage of at least 90% of meters within a max of 3 hops for electric/DER. The RF Mesh Network will be designed to provide coverage for 100% of customer premises except for meters remaining on the MV90 system. The network design will be continuously assessed to achieve these goals and will be revised during the optimization phase.

Rhode Island Energy has a strong preference to utilize utility owned poles and infrastructure for deployment of network devices. As such, the Network Deployment Vendor will be designing the RF mesh network to meet this requirement utilizing best efforts. There are also specific requirements for deployment of large Gateways with regards to substation and facility locations where fiber optic networks are available or planned to be deployed in the near future.

3.5.1.3. Network Device Site Survey

Site Surveys are a field activity designed to identify suitable mounting locations for network devices (Gateways and Routers) in accordance with the approved Engineering and Standards drawings.

There are various parameters that should be considered when planning site surveys, such as ease of installation, minimal make ready work, truck access and appropriate mounting locations for optimum RF performance. Once the site surveys are conducted by the Network Deployment Vendor field engineers, Rhode Island Energy will review and approve the design of Gateways to commence construction. The formal approval process will not be required for Routers to allow flexibility and quick turn-around for deployment of these devices. The Network Deployment Vendor is required to abide by guidelines set through engineering standards group for deployment of these devices.

The site survey process will be utilized to confirm the feasibility and validity of the RF Network Design completed in the back office. The reality of a particular geographic location visited in the field may be considerably different than what is viewed topographically on a map. The Network Deployment Vendor field engineers will visit both primary and alternative design locations to confirm:

1. Pole Location
2. Road Access
3. Gateway Mounting Feasibility
4. Work Site Safety at the Location
5. RF Signal Strength
6. Cellular Backhaul Strength Network Gateway & Router Deployment

Gateways and Routers are deployed ahead of meter roll-out in target deployment sectors per the Field Deployment Schedule developed and approved by Rhode Island Energy. The Network Gateways are provisioned and commissioned with the Head-End systems on the day of installation. A (at least daily) software interface between the network deployment vendor and Head End and Asset Systems will be in place to monitor progress against plan, work out data issues, monitor operation of the network, and track asset information including field location. The network roll-out will also be planned with consideration of neighboring sector deployment as the deployment activities continue in order to accommodate mesh formation.

3.5.2. Meter Deployment

3.5.2.1. Overall Meter Deployment Methodology & Approach

As the RF mesh meter deployment solution will automate the reading of meters during the bill window, all new RF mesh meters will need to provision and commission with the head-end systems within 48 hours of being deployed in the field (i.e., "same-day provisioning").

As discussed previously, the same-day provisioning and billing requirements will dictate the overall roll-out approach. The network Gateways and routers will be deployed in advance within target sectors, and subsequently the meter deployment will need to occur with geographic and design consideration for proximity to network Gateways and RF mesh build-out. To promote RF mesh propagation and a more stable mesh network, meter deployment will happen in a staged fashion taking into account mesh strength and potential for communication disconnect within the network. The optimization field technicians will also prioritize their remediation activities focused on meter roll-out in a target sector.

It is also critical to note that meters will not be deployed during black-out window (the several-day time period both before and after the billing calculation date that could be impacted by a meter exchange).

A software interface between the meter deployment vendor and Rhode Island Energy's systems, which will occur at least daily, will be used to drive and track progress of the meter installation work, work out data issues, as well as collect a variety of premise information (inside/outside, GPS coordinates, photos, reads, etc.) for use in the Head End and other systems. The interface will be the method by which data errors are reported and corrected to keep the deployment activities moving while installation crews are active in the current sector.

3.5.2.2. Special Considerations

Minor and Major Repairs

The deployment vendor will also coordinate and complete all required meter socket and service repairs to ensure a safe exchange. The installation crews will identify meter panel service conditions that prevent a safe exchange and document these conditions.

All critical and emergency conditions will be reported immediately and made safe until remediation activities are conducted and power is restored. As a part of the meter installation, the installation / repair crews will conduct minor repairs not requiring an electrician, including:

- Tightening loose fittings in Meter panels

- Securing minor loose Meter panel to structure
- Minor loose line or load side conductors
- Seal holes in socket

All other major repairs will require coordination with a qualified electrician and will include inspection to ensure safety. A customer waiver will be required to conduct major repairs, although Rhode Island Energy will include the cost of these repairs as part of the Rhode Island AMF program. The following are various major repair categories as part of the scope of work for the deployment vendor:

Meter Base Repair

- Reattach and align base for pulled away underground service
- Broken test blocks

Meter Base Replacement

- Inoperative service breaker / by-pass lever
- Damaged fuse blocks or fuses, unless they interfere with proper meter operation (ex. 240 V, 3 wire, old sequence)
- Replace Meter base
- Replace jaw assembly and neutral lug repair

Service Entrance Cable Repair

- Loose line or load side conductors
- Splice feeders to extend (UG service)
- Repair damage or overheated insulation on wire with heat shrink
- Replace service entrance cable

Overhead or Underground Conduit Repair

- Damaged weather heads

- Repair broken conduit

There is also a separate category of repairs that will be completed post deployment of RF mesh meters. Some of these repair categories include:

- Conversion of 60 AMP bases to 100 AMPS
- Installation of security devices (i.e., bars) on Meter banks
- Resolution of remaining Unable to Complete (UTC) meters that could not be addressed within the Meter installation program (inaccessible, safety issue)

Installs Unable to Complete (UTC)

There may be a small number of exchange orders that will not be completed by the vendor and may be returned to the deployment team for further resolution. The deployment vendor will adhere to the following 9 step multi-attempt process before requesting to return exchange orders:

- Vendor will complete three field visits at three different times (morning, afternoon, and evening), each on a different day, with at least one day being on the weekend (Installation vendor to schedule repair crews as appropriate during weekends)
- Vendor will conduct three call center phone attempts at three different times each on a different day with at least one day being on the weekend
- Vendor will also complete three written attempts

Once the above-described attempts are exhausted, the exchange order will be reviewed by the deployment team in a weekly premise review process prior to deeming the order as UTC. The UTCs may be returned to the deployment vendor at a later time once access / safety issues are resolved.

There are situations where due to permanent obstruction, safety, or customer refusal, the premise review process will be initiated prior to exhausting all 9 attempts described above. The deployment team will coordinate with vendor to seek resolution to proceed with the meter exchange.

The exchange order will not be considered a UTC where meter / address mismatch occurs and the vendor is advised to proceed with the installation and provide sufficient information to allow Rhode Island Energy to resolve billing related exceptions post processing the order in CSS.

Theft and Diversion

While installing meters the deployment crews may come across theft/tampers conditions such as suspicious wiring or back-feed detected on non-net metering accounts. In these instances, the deployment vendor is responsible for documenting the evidence and notifying the deployment team for further investigation. Once these investigations are concluded, these exchanges will be transferred back to the field installation vendor once work items are complete.

There may be other instances and conditions that will require documentation and collection of the evidence (e.g., meter tagged and returned to Rhode Island Energy), but the deployment vendor is responsible to complete the installation of the RF mesh Meter. The following are examples of such conditions:

- Hole in meter glass and/or wire inserted
- Internal obstruction
- Inverted meter
- Suspect tampering
- Does not register
- Missing meter cover seal
- Jumper in socket, unauthorized cut in flats
- Meter potential clip found open and/or wire attached
- Stopping meter disk with foreign object
- Magnets
- Unauthorized reconnect
- Foreign or stolen meter found/meter not on record/no replacement order for this meter
- Found - evidence of underground or overhead tap before the meter

MV90 Accounts

There are approximately 1,200 MV90 meters currently in service within the Rhode Island territory. After detailed assessment of capabilities and requirements based on type of meters in service on the MV90 system, the project team has recommended to migrate these meters to the RF mesh network except for 2510, 8600, and 8650 model meters utilized on large (>69kV) services. As such, a small population of MV90 meters will not be transitioned to RF mesh network (~901 meters).

The recommendation for how to account for MV90 in the new RF Mesh network is to change out the existing meters that can be migrated to RF Mesh and retain the MV90 system for those that cannot.

Rhode Island Energy will take a cautious, staged approach to the transition. This approach will include cutting over a representative sample that fall within the sector or sectors used for the Solution Validation Phase. Once these meters have been transitioned and Rhode Island Energy is satisfied with their reliable operation, the transition of the remaining meters will then occur throughout the deployment process, with a special focus on RF mesh network stabilization prior to migrating this population.

Inactive Meters

All Form 1S Class 100, Form 2S Class 200, Form 2S Class 320, and Form 12S Class 200 AMF meters will have remote reconnect and disconnect capability. For inactive meter exchanges, the utility will make a subset of meters available to the field installation vendor with the internal reconnect/disconnect switch in the open (disconnected) position to ensure power is not inadvertently reconnected at the time of the exchange. Services that have been inactive for more than two years require an inspection prior to reconnecting service and therefore may be excluded from a meter exchange.

Net-Metered Services

Services that are connected to a solar panel or photovoltaic system (< 25 kW capacity) may need to have the system de-energized to avoid reverse energy flows, or back feed, when the meter is exchanged. In such cases, the field installation vendor will schedule an appointment with the customer.

Load Research Meters

The current population of load research meters used to collect sample load shape data on a select pool of residential and small commercial customers in Rhode Island will continue during the

AMF deployment. The load research meters will be replaced with AMF meters as defined in the Deployment Plan. No data will be lost due to the AMF exchange. As AMF meters begin to replace AMR, the pool of meters that can support Load Research will increase as all meters will provide 15-minute interval data.

3.5.3. Solution Validation Phase

The Solution Validation Phase will commence in July of 2024 after a portion of meters within the Westerly Sector are deployed. Solution Validation will allow the Deployment team to perform end-to-end testing of Network and Meter communications and validate that back-office Systems and processes are working as anticipated ahead of Full Meter Deployment.

Solution Validation testing will include Network and Meter communications testing, Systems Testing including Head End, Meter Data Management System, and Billing.

The Solution Validation Phase exit criteria will be established and monitored by the PMO team and reported out to the Executive Steering Committee.

3.5.4. RF Mesh Mitigation and Sector Optimization

The network optimization activities commence immediately following deployment of meters in a target sector. All RF-challenged meters will be identified by the team analyzing meter deployment daily and field technicians dispatched to the area to conduct appropriate remediation activities. These remediation activities consist of deployment of RF mitigation aids such as antennas or deployment of additional network devices (e.g., Routers). The construction packages for any RF network aids and devices deployed will be completed in the field and brought back to update appropriate asset management systems daily while deployment work progresses. The details of this process will be covered in business process workshops. Once RF-challenged meters are connected to the mesh network and contractual performance SLAs and metrics are achieved within a saturated sector, the sector acceptance process will commence.

3.5.5. Sector Acceptance

The objective of the sector acceptance process is to transition the monitoring and maintenance responsibility for the meters from the Network Deployment Vendor to Rhode Island operations for each saturated sector as deployment and optimization activities are finalized in a geographic sector.

Sector Acceptance is achieved when the AMF Network Deployment Vendor can provide documented metrics demonstrating the sector has met all agreed Performance Metrics for an agreed period of time and the UTC meter installation rate is at or below the predefined levels.

It is important to note that once the sector acceptance process is completed within a given geography, any further meter deployment and maintenance activities will be completed by Rhode Island Energy field operations teams. There are circumstances where the deployment vendor may be required to coordinate deployment of Unable to Complete (UTC) orders post - acceptance, but this activity will be managed on an exception basis. Rhode Island Energy will be responsible for any new connections and developments post sector acceptance. The sector acceptance happens throughout the deployment phase of the project, but the AMF Network Deployment Vendor will remain responsible for management of operational functions of the Head End System application and the RF network devices through the Final System Acceptance, which is beyond the deployment phase timeline.

Sector acceptance metrics are categorized by the following:

1. Consecutive Days of Metrics being achieved
2. System Configurations
3. All Assigned Meter Deployed or Accepted UTC
4. % Accepted UTCs
5. Outstanding repairs
6. Meters on Same Firmware
7. All Network Devices Deployed
8. Meter Maintenance Backlog
9. Manual Reads Actively Worked
10. Installation Vendor Missing Meters
11. Open Property Damage Claims (informational)

3.6. Deployment Operations

The deployment operations team will oversee meter and network deployment activities and processes, tools, deployment tracking and reporting, and issue identification and resolution. In this section the governance, roles and reporting structure is discussed.

3.6.1. Deployment Monitoring and Reporting

The Deployment and Metering Operations teams work in conjunction to monitor and operate the RF mesh network as it is being rolled out. The daily deployment monitoring activities consist of the following:

- Monitor Installations / Provisioning & Commissioning
- Monitor RF Mesh Formation
- Identify and Resolve Data Issues
- Identify Meters Awaiting RF Coverage
- Identify RF Challenged Meters
- Monitor Sector Performance
- Monitor RF Mitigation Activities
- Manage ongoing Mitigation Cases
- Produce Management / Metrics Reports
- Status Calls / Planning Meetings with Vendors
- Identify and Manage Risks and Issues
- Resolve issues and re-plan to achieve full deployment of all meters

On a weekly basis, the deployment team will connect with the larger PMO and project Leads and provide status and progress reporting. The weekly monitoring and reporting activities include:

- Conduct Weekly Status Meetings with Vendor
- Prepare Weekly PMO Progress Reports
- Raise Risks and Issues with PMO
- Produce Weekly Sector Performance Reports
- Conduct Weekly Supply Chain Meetings

- Participation in Weekly Customer Forum
- Resolve issues and re-plan to achieve full deployment of all meters

The deployment team will be utilizing the network and meter software interfaces along with the Head End to actively monitor the roll-out of meter and network devices and revise the schedule to dispatch the installation crews as necessary to ensure effective and timely formation of the RF mesh network and support same-day provisioning. The RF mesh network design will identify weaker areas of the network, and the deployment team will focus on monitoring the deployment of meters in such areas more closely. The network technicians are also dispatched by the Network Deployment Vendor to these areas to follow the installation crews and mitigate any RF challenged meters as identified through the Head End reporting tool.

3.6.2. Transition to Sustained Operations

The Network and Metering monitoring & operations will be transitioned to operations as defined in the Rhode Island AMF roadmap in December 2025, but the deployment operations managed by the project work-stream will continue operational process throughout the roll-out period until the middle of 2026. Once all sectors have been accepted and the overall system acceptance is obtained, the operational systems will be fully transitioned to sustainment and Rhode Island Energy will assume responsibility for management and maintenance of the infrastructure.

4. APPENDIX

4.1 Performance Metrics

Category	High Level Reporting Requirements	Performance Metrics
Pre-Sweep Verifications	▪ Ability to track total meters reviewed by field vendor ▪ Ability to report on Meters requiring Repair ▪ Ability to report on Meters missing or expected meter not found, found a different meter number ▪ Ability to report on transformers with none or missing customers ▪ Ability to report/sort on Class of Service ▪ Ability to report on Meters not accessible/locked gate, indoor, bad dog, etc. ▪ Ability to report on Meters with Safety Concerns ▪ Ability to report Theft scenarios (Revenue Protection consideration) ▪ Ability to report on customer complaints (for Call Center follow up)	▪ Total Meters Reviewed ▪ Total Meters requiring Repair ▪ Counts of UTCs ▪ UTC Reason Code Breakdown

Meter Deployment	▪ Ability to track meter installation and replacement progress and productivity by geographical segments / sectors ▪ Ability to track and report on work order status by sector ▪ Ability to identify and track service orders separately ▪ Ability to analyze UTC reasoning and report on trends ▪ Ability to reconcile invoices from Deployment Vendor as applicable ▪ Ability to report on new connects, maintenance work ▪ Ability to manage meter related defects and report on recovery programs ▪ Ability to report on the inventory and RMA process ▪ Ability to report on current inventory levels and forecast safety stock ▪ Ability to report on vendor installation errors / faulty installs ▪ Ability to report on safety performance metrics ▪ Ability to report separately on repair progress and all facets as appropriate	▪ Total Meters Installed (Wkly, YTD, PTD) ▪ Vendor Installations (Wkly, YTD, PTD) ▪ UTC Volume (PTD) ▪ UTC Reason Code Breakdown (PTD) ▪ On Hand Inventory (SC, TR) ▪ Vendor Safety Stock (# of Wks) ▪ Socket Repairs (YTD, PTD) ▪ Recordable Safety Incidents, vehicle incidents, Lost time (YTD, PTD)
Customer Experience	▪ Ability to track customer notifications ▪ Ability to monitor customer contact statistics from Vendor Call Center ▪ Ability to analyze trends regarding disputed installations ▪ Ability to monitor customer complaints, issues, and claims encountered during the deployment phase ▪ Ability to track Opt Out customers	▪ Customer notifications (Wkly, YTD, PTD) ▪ Disputed Installs (Wkly, YTD, PTD) ▪ Complaints, Claims (Wkly, YTD, PTD) ▪ Contact Center Call/Email Volume and Performance Metrics (Vendor) ▪ Serious Threats (Wkly, YTD, PTD) ▪ Suspected Diversion Cases (PTD) ▪ Customer Opt Out %
Back-Office / Customer Care	▪ Ability to report on data and workflow exception processing volumes ▪ Ability to monitor Deployment Back-Office activities ▪ Ability to generate ad hoc reports and conduct analytics ▪ Ability to report on billing exceptions and potential high bill issues ▪ Ability to report on UTC resolution process and aging	▪ Data / Processing Exception Volumes (YTD, PTD) ▪ Billing Exceptions (Wkly, YTD, PTD) ▪ UTC Aging (<4 wks, 4-8 wks, >8 wks)
Network Deployment	▪ Ability to track metrics related to site survey process ▪ Ability to monitor installation progress against plans ▪ Ability to identify additional infrastructure requirements ▪ Ability to track network hardware deployment statistics by geographical segments / sectors ▪ Ability to track inventory of network hardware ▪ Ability to report on field deployment related issues	▪ Site Surveys Conducted (Wkly, YTD, PTD) ▪ Gateways / Routers Installed (Wkly, YTD, PTD) ▪ Gateways / Routers in Inventory
Network Optimization and Sector Acceptance	▪ Ability to report on Optimization and Sector Acceptance process ▪ Ability to monitor and report on AMF FAN communication statistics ▪ Ability to identify relationships between meters, Gateways and Routers ▪ Ability to identify serving ratios for business case analysis (Meters / Router, Meters / Gateway, etc.) ▪ Ability to monitor contractual performance metrics	▪ Meters Registered & Provisioned ▪ 7-Day / 30-Day Read Rate Performance ▪ Sector Comm. Performance ▪ Sectors Pending / Accepted (YTD, PTD)

4.2 Pre-Sweep Checklist

1. Is the Service Overhead or Underground?

- Dropdown Choices – O or U

2. **Where is the meter located at the premise?**
    - Dropdown Choices – Rear, Front, Left Side, Right Side, Pole, Remote (not attached to premise)
3. **Is the meter located Inside or Outside?**
    - Dropdown Choices – I or O
4. **Was the meter 'Hard to Access'?**
    - Dropdown Choices - Y or N
5. **What is the service size?**
    - Dropdown Choices -A Base, 60, 100, 200, 320, 480
6. **What does the meter service?**
    - Dropdown Choices – Apartment Complex, Farm, Small Business, Residence, Lighting, CATV, Mobile Home, Other
7. **Does the site have a Multi-Gang Meter base (2 or more meters)?**
    - Dropdown Choices - Y or N
8. **Was the meter seal broken?**
    - Dropdown Choices - Y or N
9. **Does the site show any signs of tampering?**
    - Dropdown Choices – Y or N
10. **Does the meter base appear to be in need of any repair work?**
    - Dropdown Choices -Y or N
11. **Does the meter or premise require remediation prior to meter deployment?**
    - Dropdown Choices – None Required, Vegetation Management, REMSI Violation, Safety Concern

12. Who is the meter base manufacturer?

- Dropdown Choices -L&G, Anchor, Milbank, Talon, Murray, Square D, other

13. What are the Geo Spatial Coordinates?

- Lat & Long for meter location

14. Were there any customer concerns?

- Dropdown Choices – No Customer Contact, Positive Interaction, Negative Interaction, Follow Up Required with Customers

15. Missing Meter is located

- Record associated transformer number and premise address

16. General Comments

- Free form – type in note

Attachment E

DATA LATENCY BENCHMARKING

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a Rhode Island Energy
RIPUC Docket No. 22-49-EL
In Re: Advanced Metering Functionality Business Case
Data Latency Benchmarking
Attachment E
Page 1 of 1

The table below presents the results of a survey performed by National Grid of data latency for various smart meter installations that have been installed by peer utilities across North America.

Data latency industry comparison - Electric

Utility	Read Interval	Frequency of Upload to Head End System	Delay in Data Posted	Type of Data Posted (Raw vs. Validated)
Entergy	15 min for Res (90%) 5 min for C&I (10%)	6x day	Next day	Validated
OG&E	15 min	Res (4x day) Portal (24x day) Demand Response (96x day)	Everyone else (Daily) Portal Customers (1 hour) Demand Response (15 mins)	Raw data is posted, then 24 hours later it is updated after validation
ppl	15 min	6x day	Next day	Validated
Xcel Energy	15 min	6x day	Next day	Validated
Hydro Québec	15 min for Res (90%) 5 min for C&I (10%)	6x day	Next day	Validated
ComEd (An Exelon Company)	30 min	6x day	Next day	Validated
Duke Energy	30 min (90%) / 15 min (10%) based on jurisdiction	1x day	Next day	Validated
West Penn Power, Penelec, Penn Power, Met-Ed	60 min for Res (90%) 15 min for C&I (10%)	1x day	Next day	Validated
hydro one	60 min	2x day	Next day	Validated
Oncor	60 min for Res 30 min for C&I	Ongoing	Next day	Validated
PECO (An Exelon Company)	60 min for register-billed accounts; 15 min for interval-billed accounts	6x day	Next day	Validated
Vectren Live Smart	60 min (93%) / 5 min (7%); Electric MV90 - 5 min	3x day	N/A - Not presented at this time	NA

Attachment F

SAMPLE CUSTOMER COMMUNICATIONS

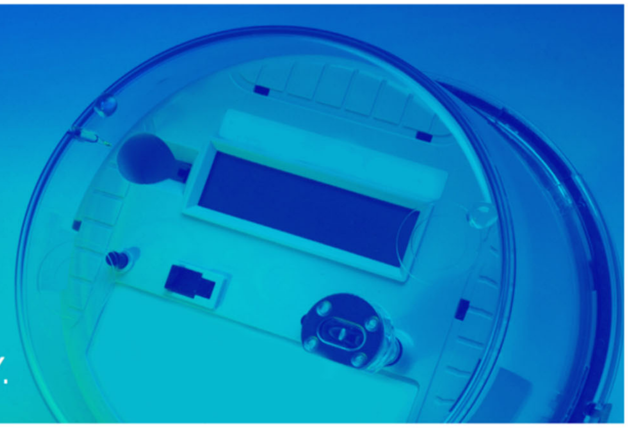
The following brochures are samples of communications that were used by PPL to deploy AMF in Pennsylvania. These are representative of what will be used: the Company plans to make adjustments to messaging to reflect specifics for the Rhode Island deployment.

Phase 1 Example Communications:

NEW METER FACT SHEET

Data Privacy

OUR METERS. YOUR PRIVACY.



We know **privacy matters** to you.

We take privacy very seriously as well.
You trust us with personal information related to your account, and we work hard to keep it secure.

When we install our new meters, we will continue to **carefully protect** our customers' information.

All data transmitted by our new meters will be **encrypted and protected**, using **multiple layers of safeguards** designed to keep your electricity usage data private. We will **meet all regulatory requirements** for protection.

We have a **strong track record** of protecting our customers' information. This will continue when we install new meters.

Because privacy matters.

You will receive more information about our new meters in the months leading up to our scheduled replacement of your meter.

ppl
PPL Electric Utilities

You can also:
Visit www.pplelectric.com/newmeters
Call 877-887-0358

We know **health matters** to you.

Our new meters will use **low-level radio-frequency signals** to send electricity usage information to our billing system.

We've heard questions about what that means to health. Here are the answers:

- Many government agencies, regulatory agencies and health organizations have studied the issue. **None have found a scientific link to any health risks** caused by the use of this type of meter in homes and businesses.
- The signals used by our new meters will be similar to those used in **everyday appliances** like garage door openers, wireless networks and security systems.
- Our meters typically transmit for **only a few minutes per day**, and not continuously.
- Our meters will meet **all applicable safety standards,** including those set by the Federal Communications Commission.
- Meter manufacturers follow **stringent standards** established by the American National Standards Institute. We require manufacturers to test the meters and conduct our own tests to ensure meters meet these standards.
- Scientific research on radio frequency fields and health has been **conducted for decades**, most recently on cellular phone frequencies.

Simply put, we wouldn't install equipment in your home or business – or our own – without **solid assurance** that it's safe.

You will receive more information about our new meters in the months leading up to our scheduled replacement of your meter.

ppl
PPL Electric Utilities

You can also:
Visit www.pplelectric.com/newmeters
Call 877-887-0358

Questions you might have

Can I keep the meter that's currently installed at my home or business?
No. The state law and regulations that require us to upgrade our meters do not include a provision allowing customers to opt out. Also, our current meters are approaching the end of their useful lives. It's our intention to replace every customer's meter.

What if I have concerns or questions about my new meter?
Please feel free to call **877-887-0358** and we'll be glad to discuss your concerns and answer your questions.

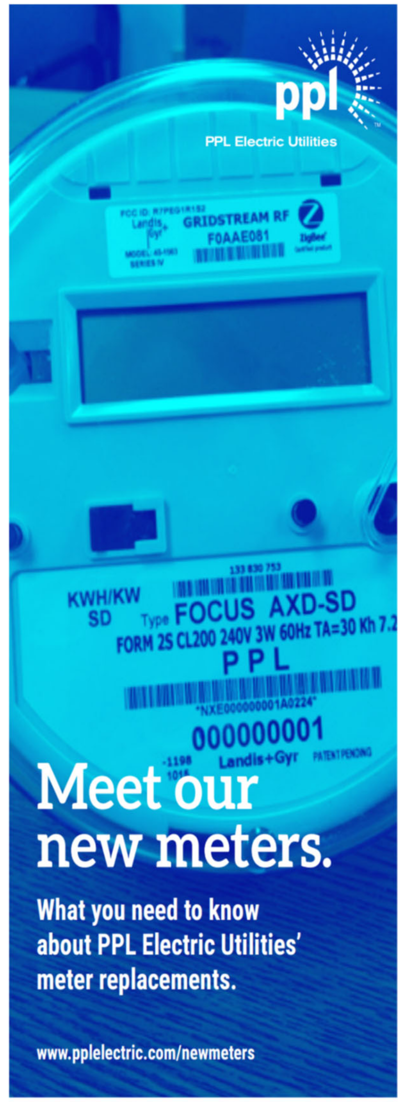
When will my meter be replaced?
We will be in touch with you about 45 days before meters are replaced in your area. A schedule of upcoming replacements will be posted online at pplelectric.com/newmeters.

Should I be concerned about the privacy of my information with these new meters?
No. As we always have done, we will carefully protect our customers' information, consistent with all regulatory requirements. All data transmitted by the meters will be encrypted and protected by PPL Electric Utilities. The new meter system will have multiple layers of safeguards designed to keep your electricity usage data private.

Some people have expressed health concerns related to this type of meter. Is that an issue?
Many government agencies, regulatory agencies and health organizations have studied the issue, and none has found any health risks caused by the use of this type of meter in homes and businesses.

PPL Electric Utilities

For more information, visit
www.pplelectric.com/newmeters.



Meet our new meters.

What you need to know about PPL Electric Utilities' meter replacements.

www.pplelectric.com/newmeters

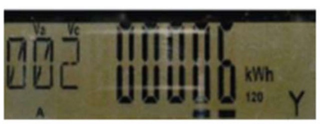
Job Aid: How to Read the New RF Meter

This Job Aid describes the Landis+Gyr RF meter screens used to confirm meter status after an install or meter replacement is completed. These six information screens loop as the meter operates.

1

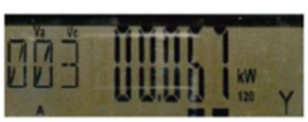
The first screen – marked with the number 001 – shows how much **energy** has been **delivered to the property**. The display does not reset to zero each month. In order to get a handle on the monthly usage, the customer will check the total on the same date each month and subtract the prior month's reading from the latest reading.

2



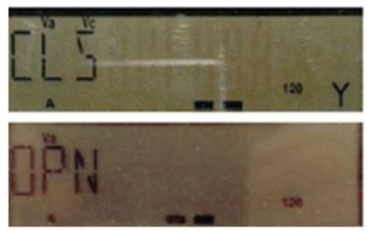
The next screen, marked with the number 002, shows how much **energy the property has delivered to the energy grid only** if there are solar panels or another type of generation installation. If the customer doesn't have one, this screen will remain at zero.
This display also does not reset. If the customer wants to take a monthly reading, they will have to check on the same date each month and subtract the prior month's reading from the latest reading.

3



The next screen, marked with the number 003, displays demand – the peak amount of electrical energy the property has consumed during the day. Unlike other displays, the demand resets each night.

4

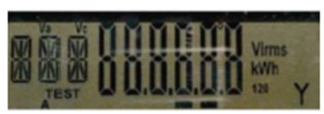


The next screen will say "CLS" if the switch inside the meter is **closed** and power is flowing to the property. **It will say "OPN"** if the switch is **open** and no power is being delivered.
If the account is in good standing, the screen should read "CLS." Confirm Switch Status, ***and complete the CMO information for the install or replacement.***

5

The next screen is blank. It can be used for troubleshooting.

6



The last screen is simply a test that shows all parts of the display are functioning.

Please note: There are a few meter types that do not include the Switch Status Screen. For example, the E0322 does not have the Switch Status display.

For all meter replacements, confirm the meter is operational before you complete the work order and all information on the CMO. This information will pair the premise and the meter for future communications from Command Center to the meter.

Phase 2 Example Communications:

Meter Infrastructure Installation Letter to Municipal Officials

Good morning,

I'm writing to update you on our state-approved project to install new meters for all 1.4 million of our customers, beginning late this year and continuing through 2019.

We are replacing our meters for several reasons, many of which involve better service for customers. The new meters will enable new energy-saving technologies, and will give customers improved access to data that will help them manage energy use. The meters will help us more quickly detect outages to improve reliability, and will help us detect energy theft and fraud to reduce costs.

Also, our current meters are reaching the end of their useful lives, and we are proactively replacing them with meters that will bring us into full compliance with state regulations on meter technology.

Before we install our new meters, we must put supporting equipment in place. We have hired a contractor, Ri[redacted]o install routers *(pictured at right)* on some utility poles and street lights in our service area. Our new meters, when installed, will send secure, encrypted data to these routers.

You might see Ri[redacted]ews out doing the work in your community, and you might notice the devices once they're attached. These installations started in June 2016 and will continue until spring 2018. Neither the installation nor the operation of these routers should have any impact on customers.

If you have questions, please do not hesitate to contact me.

45 Day Customer Notification Letter

MONTH/YEAR

Customer Name
Address
Address

Service Premise in Reference:
Address
Address
Meter ID #:

Dear Name:

In coming months, we will be replacing our electric meter on your property as part of our state-approved plan to upgrade all our customers' electric meters. Your new meter will benefit you in several ways: It will help us improve the reliability of your service by better detecting power outages. And, over time, the new meters will give you improved access to data that will help you manage your energy use.

Here's what you can expect during the replacement:

- We've hired Gri[redacted]erform meter replacement work. Their staff will carry p[redacted]trained and authorized to work on our behalf. Gr[redacted]l-free number is 1-800-254-0344. A schedule of planned meter replaceme[redacted]oto of Gri[redacted]cles will be posted online at **pplelectric.com/newmeters** for [redacted]that Gri[redacted] working in their area.
- The technician performing the installation will knock on your door before they begin working. The installation will take about 10 minutes to complete, during which time you may briefly lose power.
- You do not need to be home for the installation so long as the meter is outdoors and our technicians have clear and safe access.
- If our electric meter is located indoors, or in another location that is inaccessible, you will need to be present to provide access. Installations will take place from 8 a.m. to 5 p.m. If your meter is not accessible and you will not be available during these hours over the next few days, please contact 1-800-254-0344 as soon as possible to schedule an appointment.

We are committed to keeping all of our customers informed before their meters are replaced, and will be in touch again closer to your meter installation date.

Sincerely,

PPL Electric Utilities

Carta de notificación al cliente - 45 días antes del reemplazo

MES/AÑO

Nombre
Dirección
Dirección

Premisa del Cliente:
Dirección
Dirección
#ID del Medidor

Estimado/a Nombre:

En los próximos meses, reemplazaremos nuestro medidor eléctrico instalado en su propiedad como parte del plan aprobado oficialmente para actualizar todos los medidores eléctricos de nuestros clientes. Su medidor nuevo lo beneficiará de muchas maneras: Nos ayudará a aumentar la confianza en nuestro servicio a partir de la detección inmediata de interrupciones en la prestación. Además, con el tiempo, los medidores nuevos le brindarán mayor acceso a los datos para ayudarlo a administrar su consumo de energía.

Durante el reemplazo, puede esperar lo siguiente:

- Contratamos a [redacted] para reemplazar los medidores. Su personal llevará la identificación correcta y cuenta con la capacitación integral y la autorización que necesita para trabajar en representación nuestra. Su línea telefónica sin cargo es 1-800-254-0344. Se publicará en línea el cronograma de los reemplazos de medidores planificados y fotos de los vehículos de [redacted] **pplelectric.com/newmeters** para los clientes que deseen verific[redacted] está trabajando en su área.
- El técnico que realice la instalación tocará su puerta antes de comenzar a trabajar. La instalación llevará unos 10 minutos en completarse; durante este tiempo, se cortará brevemente la energía.
- Si el medidor se encuentra al aire libre y si nuestros técnicos pueden acceder a él de manera concreta y segura, usted no necesita encontrarse en su hogar.
- En cambio, si el medidor está en el interior de su hogar o en otra ubicación poco accesible, deberá estar presente para brindar acceso a él. Las instalaciones se llevarán a cabo desde las 8 a.m. hasta las 5 p.m. Si no se puede acceder a su medidor y usted no está disponible durante este horario en los siguientes días, contacte a 1-800-254-0344 tan pronto como sea posible para programar una cita.

Nos comprometemos a mantener informados a nuestros clientes antes de reemplazar sus medidores y los volveremos a contactar cerca de la fecha de instalación.

Atte.

PPL Electric Utilities

21 Day Customer Notification Letter

MONTH/YEAR

Customer Name
Address
Address

Service Premise in Reference:
Address
Address
Meter ID #:

Dear Name:

Within the next month, we will be replacing our electric meter on your property as part of our state-approved plan to upgrade all our customers' electric meters. Your new meter will benefit you in several ways: It will help us improve the reliability of your service by better detecting power outages. And, over time, the new meters will give you improved access to data that will help you manage your energy use.

Here's what you can expect during the replacement:

- We've hired Gr[redacted]perform the meter replacement. Their staff will carry proper identific[redacted]lly trained and authorized to work on our behalf. Their toll-free number is 1-800-254-0344. A schedule of planned meter replacements and a photo of a Gr[redacted]icle will be posted online at **pplelectric.com/newmeters** for customers wish[redacted]fy that Gri[redacted]orking in their area.
- The technician performing the installation will attempt to notify you before they begin working. The installation will take about 10 minutes to complete, during which time you may briefly lose power.
- You do not need to be home for the installation so long as the meter is outdoors and our technicians have clear and safe access.
- If our electric meter is located indoors, or in another location that is inaccessible, you will need to be present to provide access. Installations will take place from 8 a.m. to 5 p.m. If your meter is not accessible and you will not be available during these hours over the next few days, please contact 1-800-254-0344 as soon as possible to schedule an appointment.

We are committed to keeping all of our customers informed before their meters are replaced, and will follow up with a phone call before installation. More information on this project is available at **www.pplelectric.com/newmeters.**

Sincerely,

PPL Electric Utilities

Carta de notificación al cliente - 21 días antes del reemplazo

MONTH/YEAR

Nombre
Dirección
Dirección

Premisa del Cliente:
Address
Address
Meter ID #:

Estimado/a Name:

En el próximo mes, reemplazaremos nuestro medidor eléctrico instalado en su propiedad como parte del plan aprobado oficialmente para actualizar todos los medidores eléctricos de nuestros clientes. Su medidor nuevo lo beneficiará de muchas maneras: Nos ayudará a aumentar la confianza en nuestro servicio a partir de la detección inmediata de interrupciones en la prestación. Además, con el tiempo, los medidores nuevos le brindarán mayor acceso a los datos para ayudarlo a administrar su consumo de energía.

Durante el reemplazo, puede esperar lo siguiente:

- Contratamos a [redacted] para reemplazar los medidores. Su personal llevará a cabo la identificación correcta y cuenta con la capacitación integral y la autorización que necesita para trabajar en representación nuestra. Su línea telefónica sin cargo es 1-800-254-0344. Se publicará en línea el cronograma de los reemplazos de medidores planificados y una foto del vehículo de [redacted] en **pplelectric.com/newmeters** para los clientes que deseen verificar si [redacted] está trabajando en su área.
- El técnico que realice la instalación intentará avisarle antes de comenzar a trabajar. La instalación llevará unos 10 minutos en completarse; durante este tiempo, se cortará brevemente la energía.
- Si el medidor se encuentra al aire libre y si nuestros técnicos pueden acceder a él de manera concreta y segura, usted no necesita encontrarse en su hogar.
- En cambio, si el medidor está en el interior de su hogar o en otra ubicación poco accesible, deberá estar presente para brindar acceso a él. Las instalaciones se llevarán a cabo desde las 8 a.m. hasta las 5 p.m. Si no se puede acceder a su medidor y usted no está disponible durante este horario en los siguientes días, contacte a 1-800-254-0344 tan pronto como sea posible para programar una cita.

Nos comprometemos a mantener informados a nuestros clientes antes de reemplazar sus medidores y haremos un seguimiento con una llamada telefónica antes de la instalación. Obtenga más información sobre este proyecto en **www.pplelectric.com/newmeters.**

Atte.

PPL Electric Utilities

1 Day Auto Dial Message

Hello, this is PPL Electric Utilities calling with important information about our electric meter on your property.

As you may be aware, we will be replacing the electric meter on your property within the next few days. You may lose power briefly – typically for less than a minute - while we complete this work.

[redacted] a contractor hired and approved by PPL Electric Utilities, will replace the meter. The technician performing the installation will try to notify you before they begin working.

If our electric meter is already accessible, simply do nothing.

If our electric meter is located indoors, or in another location that is inaccessible, you will need to be present to provide access. Installations will take place from 8 a.m. to 5 p.m. If your meter is not accessible and you will not be available during these hours over the next few days, please contact 1-800-254-0344 as soon as possible to schedule an appointment.

Thank you for your cooperation.

Mensaje telefónico automático 1 día antes del reemplazo

Hola. Nos comunicamos de PPL Electric Utilities para brindarle información importante sobre nuestro medidor eléctrico instalado en su propiedad.

Como debe ser de su conocimiento, reemplazaremos el medidor eléctrico en su propiedad dentro de los próximos días. Es probable que se interrumpa la energía brevemente (por lo general, por menos de un minuto) mientras completamos el trabajo.

El reemplazo del medidor estará a cargo de [redacted] cuyo servicio fue contratado y aprobado por PPL Electric Utilities. El técnico que realice la instalación tratará de avisarle antes de comenzar a trabajar.

Si se puede acceder fácilmente a nuestro medidor eléctrico, no necesita hacer nada.

En cambio, si el medidor está en el interior de su hogar o en otra ubicación poco accesible, deberá estar presente para brindar acceso a él. Las instalaciones se llevarán a cabo desde las 8 a.m. hasta las 5 p.m. Si no se puede acceder a su medidor y usted no está disponible durante este horario en los siguientes días, contacte a 1-800-254-0344 tan pronto como sea posible para programar una cita.

Gracias por su cooperación.

1st No Access Letter

MONTH/YEAR

Customer Name
Address
Address

Service Premise in Reference:
Address
Address
Meter ID #:

Dear Name:

Our efforts to reach you and schedule a time to replace our electric meter on your property have not been successful. The replacement of your electric meter is required by Pennsylvania law, and this work is mandatory, not optional.

To complete the work, our technicians need clear access to the electric meter at your property. Appointments are available on any weekday between 8 a.m. and 7 p.m. and on Saturdays between 8 a.m. and 4 p.m. Special needs will be accommodated whenever possible.

We've hired [redacted] to perform the meter installation. [redacted] employees arrive in clearly marked vehicles and display picture identification badges. The work will take about 10 minutes to complete, during which time you may lose power briefly.

Please call **1-800-254-0344** to schedule the meter replacement. We appreciate your prompt cooperation and assistance in helping us to complete this work as soon as possible. Failure to have the meter on your property replaced will eventually result in the shutoff of your electric service.

If your meter was replaced after the date of this letter, please disregard this notice. Thank you for your cooperation.

Sincerely,

PPL Electric Utilities

EMF and Health Information

What is EMF? "EMF" is an abbreviation for "electric and magnetic fields" and also for "electromagnetic fields." Power lines, appliances, and home wiring all produce electric and magnetic fields. "EMF" is also commonly used to refer to just "magnetic fields." Some people are concerned about whether magnetic fields cause adverse health effects. In the information below, "EMF" refers to magnetic fields.

Is EMF "radiation" like medical X-rays or ultraviolet sunlight? No. Radiation from medical X-rays and from the ultraviolet part of sunlight is strong enough to damage DNA. EMF from power lines, appliances, and home wiring is not.

What are the EMF levels from common sources?

Examples of EMF Sources* (in milligauss)	
Coffee makers	7
Distribution line upper level of typical average	20
Dishwashers	20
500 kV transmission line typical average at edge of right-of-way	30
Distribution line typical maximum above underground line	40
Florescent lights	40
Distribution line typical maximum under overhead line	70
Blenders	70
500 kV transmission line typical average under the line	87
Toasters	100
Hair dryers	300
Can openers	600

* People typically change activities and locations during a day, so we are exposed to a variety of sources of EMF and a wide range of field levels. In the table above, field levels are taken from the U.S. National Institute of Environmental Health Sciences (NIEHS), Electric and Magnetic Fields Associated with the Use of Electric Power, EMF Questions & Answers, pages 33-35 (median level at 6 inches from appliances), page 36 (distribution lines), and page 37 (transmission lines). As noted by NIEHS, field levels of transmission lines can approximately double during peak loads, which occur about 1% of the time.

What conclusions have public health authorities reached about whether EMF causes health effects? The EMF health research has been examined by governmental public health authorities and public health organizations in over 200 reports. The World Health Organization has examined the reports on the research and says on its website:

> **Based on a recent in-depth review of the scientific literature, the WHO concluded that current evidence does not confirm the existence of any health consequences from exposure to low level electromagnetic fields.**

https://www.who.int/news-room/q-a-detail/radiation-electromagnetic-fields (Radiation: Electromagnetic fields – Biological effects or health effects? What is a health hazard? – Conclusions from scientific research)

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Are there any EMF exposure guidelines? Yes. Two international expert groups have issued exposure guidelines based on avoiding very high levels of exposure that can produce short-term biological responses, such as the perception of a faint flickering of light or a tingling on the skin. The international expert groups are the Institute of Electrical and Electronics Engineers (IEEE) and the International Commission on Non-Ionizing Radiation Protection (ICNIRP). Both groups of experts have concluded that no adverse health effects occur at EMF levels below their exposure guidelines.

EMF levels under a typical 500 kV high voltage transmission line are 95% below the strictest guideline.

Typical EMF Levels from Power Lines*
compared to
EMF Exposure Guidelines
(in milligauss)

IEEE exposure guideline for general public	9,040
ICNIRP exposure guideline for general public	2,000
500 kV transmission line typical average under the line	87
Distribution line typical maximum under overhead line	70
Distribution line typical maximum above underground line	40
500 kV transmission line typical average at edge of right-of-way	30
Distribution line upper level of typical average	20

* All power line levels above are taken from U.S. National Institute of Environmental Health Sciences (NIEHS), Electric and Magnetic Fields Associated with the Use of Electric Power, EMF Questions & Answers,, pages 36 and 37. As noted by NIEHS, field levels of transmission lines can approximately double during peak loads which occur about 1% of the time.

How much research has been done on EMF and health?

EMF-Health Effects Research Totals *
more than
44 years **2,900 studies** **$490 million spent**

* Repacholi M, "Concern that 'EMF' magnetic fields from power lines cause cancer." Sci Total Environ (2012), doi:10.1016/j.scitotenv. 2012.03.030, page 3. [citing PubMed]

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Your electric meter is being upgraded.
Trained service technicians will be in your area replacing meters as part of an Advanced Meter upgrade approved by the Kentucky Public Service Commission.
Advanced Metering Infrastructure (AMI) incorporates two-way communicating advanced meters which support automated meter reading, faster connection of electric service, and provide information to help us reduce outages and respond more quickly when there is an outage.
Learn more at lge-ku.com/ami
LG&E KU
PPL companies

SEW 10-DAY NOTIFICATION

Voice Call – LG&E

Hello, this is L G and E calling with a reminder that service technicians will be in your area exchanging meters in the next ten days. This service is part of our A-M-I project and is at no additional cost to you. If you have questions or concerns, please give us a call at 8, 0, 0, 3, 3, 1, 7, 3, 7, 0 or visit w w w dot l g e dash k u dot com slash a m i.

Voice Call – KU residential

Hello, this is K U calling with a reminder that service technicians will be in your area exchanging meters in the next ten days. This service is part of our A-M-I project and is at no additional cost to you. If you have questions or concerns, please give us a call at 8, 0, 0, 9, 8, 1, 0, 6, 0, 0 or visit w w w dot l g e dash k u dot com slash a m i.

.

Voice Call – KU business

Hello, this is K U calling with a reminder that service technicians will be in your area exchanging meters in the next ten days. This service is part of our A-M-I project and is at no additional cost to you. If you have questions or concerns, please give us a call at 8, 0, 0, 3, 8, 3, 5, 5, 8, 2 or visit w w w dot l g e dash k u dot com slash a m i.

.

Text

LG&E and KU: Reminder: Technicians will be in your area for the next 10 days exchanging meters as a part of our AMI project. Reply HELP for help.

Advanced Metering Infrastructure (AMI)
Residential Phone:
LG&E: 800-331-7370 | KU: 800-981-0600
Business Phone:
LG&E: 800-331-7370 | KU: 800-383-5582

LG&E KU
PPL companies

Address

<Insert Date>

Meter replacement project

Dear Valued Customer,

In the next several weeks, trained service technicians working on behalf of LG&E and KU will be in your area replacing meter(s) as part of a meter upgrade approved by the Kentucky Public Service Commission. New advanced meters help you manage your home's energy use and allow us to offer new tools and services.

During the meter exchange process:
- A technician from Utilit[redacted]xchange your meter. They carry photo identification and will not need to come inside unless they cannot get to your meter.
- They will attempt to notify you upon arrival before they begin work. Installation should take 5 to 15 minutes for each meter. Sometimes a brief interruption of power may be needed.
- You do not need to be present if there is clear and safe access to your outside meter(s). If your meter access is restricted, please contact UPA at **800-914-4179** to schedule a meter exchange appointment.
- If you do not wish to receive an advanced meter, please visit lge-ku.com/ami-opt-out and fill out the contact form. We will contact you about the opt-out process and associated monthly fees you will incur.

Visit our website at lge-ku.com/ami to learn more about the meter exchange process and the benefits of advanced meters.

PPL Electric Utilities

MONTH/YEAR

Name
Address
Address

Dear Name:

PPL Electric Utilities soon will be sending a contractor to gather some general information on your meter as part of our plan to replace all of our customers' electric meters in coming years. This meter replacement plan recently earned the approval of the state Public Utility Commission.

We are updating our customer service database in advance of the project, and some of the needed information requires our representatives to look at your meter. If your meter is outdoors, you don't need to be there because we can do all of our work from the outside. There also is no charge to you.

Over time, our new meters will give you improved access to data that will help you manage your energy use. They will also help us better detect outages, improving service reliability.

We've hired Grid One Solutions to gather meter information. Their staff will carry proper identification and they are fully trained and authorized to work on our behalf. Their toll-free number is 1-877-887-0358. A schedule of planned meter checks and a photo of a Grid One vehicle will be poste[redacted]**.com/newmeters** for customers wishing to verify that Grid One is working [redacted].

If Grid One is unable to access your meter, they will contact you to schedule an appointment. [redacted] There is no charge for inspection of these meters. [redacted]

We are committed to keeping all of our customers informed before their meters are replaced, and will be i[redacted]uch before work begins in your area. We will begin replacing meters in late 2016 and will continue until all meters are replaced in late 2019.

Sincerely,

Larry Melenchek
PPL Electric Utilities

Attachment G

CYBERSECURITY, DATA PRIVACY AND DATA GOVERNANCE PLAN

PPL Corporation

Cybersecurity, Data Privacy, and Data Governance Plan

Introduction

This **Cybersecurity, Data Privacy, and Data Governance Plan ("Plan")** provides a framework that includes a comprehensive set of principles and standards that address cybersecurity, data privacy, data governance, information classification, and enterprise security standards for PPL Corporation and its affiliates and subsidiaries ("Company").

The Plan, in conjunction with other corporate policies as identified below, has been developed to ensure the management, protection and secure availability of the Company's data and information assets. Addressing key functionalities and processes, the Plan seeks to ensure that (1) the data generated by Company and through its advanced metering functionality ("AMF")[1] is collected, managed, stored, transferred, and protected in a way that preserves customer privacy; (2) practices are consistent with cybersecurity requirements and facilitate access to further operational requirements; and (3) grid modernization objectives and Climate Mandates are met. The Plan also seeks to support critical infrastructure and vital business functions including AMF. Additionally, the Plan addresses how the Company protects the confidentiality, integrity, and availability of all data and information, data and information assets, and data and information resources to a level that is commensurate with their value. Finally, it addresses the Company's commitment to reduce the risk of information loss by accidental or intentional modification, disclosure, or destruction.

Contents

[1] "AMF" is used generically to refer to the functionality provided by advanced meters or smart meters. Recognizing that the local references differ being 'AMF' in RIE, 'AMI' in PPL EU and 'Smart Meters' in KY, for simplicity, "AMF" is being used unilaterally throughout the document to applying equally to all jurisdictions.

- Purpose
- Organizational Commitment
- Approach to Cybersecurity
- Vendor Cybersecurity Requirements Assessment
- Cybersecurity Operations
- Risk Assessment, Testing, and Quality Assurance
- Data Privacy
- Standards
- Impact on Overall AMF Security

A. Background

PPL Corporation maintains a strong commitment to cybersecurity and data privacy, continually investing in its human resources, processes and technology. The Company, in recognition of the need to maintain and enhance a defensive and in depth cybersecurity plan that seeks to prevent and mitigate everchanging cyber risks and threats, has developed and implemented pertinent policies and standards addressing cybersecurity, data privacy, data governance, information classification, and enterprise security standards in accordance with the International Organization for Standardization ("ISO") standards. Through these policies and standards, the Company's cybersecurity, data privacy, and data governance strategy seeks to support the Company's critical infrastructure and vital business functions including AMF. This strategy ensures the confidentiality, integrity, and availability of systems and data through a process to continually evaluate all aspects of AMF data and information including review of policies, standards, and procedures, and implementation of technical controls and security measures. These objectives support the Company's goal to provide safe, affordable, reliable, and sustainable energy to our customers and superior, long-term returns to our shareowners.

PPL Corporation and its family of companies provide essential energy services to about 3.5 million customers. We provide an outstanding service experience for our customers, consistently ranking among the best utilities in the U.S. As one of the largest regulated utility companies in the United States, we understand the energy we provide is vital to our customers and communities. To that end, over the past decade, PPL has invested more than $20 billion in new infrastructure and technology in our U.S. operations to create a smarter, more reliable and resilient energy grid for generations to come. As the energy grid evolves, so does PPL. PPL's companies are addressing new challenges head-on and are finding ways to accommodate new technologies, distributed generation and renewable power sources on our grid.

B. Plan Framework

The following corporate policies have been developed to ensure the management, protection and secure availability of the Company's data and information assets:

- Data Governance Policy
- PPL Standards of Integrity
- PPL Responsible Behavior Program
- Information Security (CP 403)
- Information Classification and Handling (CP 404)
- Electronic Information Security (CP 405)
- Records Management (CP 407)
- PPL Electric Cybersecurity Policy (CIP 001)
- PPL FERC Standards of Conduct (CO 810)
- PPL Enterprise Information Security Policy (CP 412)
- Data Security Standard ESS-04

Together these policies, lay out a comprehensive set of principles and standards for the customer and system data produced by the Company and its AMF deployment. These guiding principles are designed to ensure the data generated by the Company and through its AMF is collected, managed, stored, transferred, and protected in a way that preserves customer privacy, is consistent with cybersecurity requirements, and facilitates data access in furtherance of operational requirements, as well as grid modernization objectives and Climate Mandates. This Plan, as outlined here, provides a structure for how AMF data and information will be governed. The Plan also discusses system data as it pertains to AMF in the context of ongoing grid modernization efforts. The policies include an explanation of how the Company provides customers with access to data and enables the sharing of that data with non-regulated power producers and other authorized third parties.

The Company has developed a comprehensive and integrated data governance framework designed to ensure compliance with privacy, cyber, and information security regulations across all jurisdictions in which it does business. The framework is meant to ensure that customers' data and information is properly protected, but also readily available to them or any third party with whom they wish to share their data. In striking this balance and committing to the secure delivery of AMF, the Company focuses on three key data security components:

- a commitment to core data-privacy principles;
- regular assessments of the Company's performance in accordance with the principles; and
- constant vigilance.

The approach is also reflected in its risk-based cybersecurity framework that tracks across people, process, and technology:

Setting forth policies and standards intended to ensure the Company works to common security objectives by regularly updating cyber, privacy and security guidance (including incident management and reporting) for those with legitimate business needs to access customer data; addressing privacy throughout the data lifecycle, working to prevent accidental misuse/loss/exposure of information; and ensuring cybersecurity controls are implemented, information risks are understood, andtechnologies are selected to keep pace with threats.

The applicable policies included herein provide further detail of the Company's approach to data and information privacy, and its commitment to cybersecurity, security and protection.

C. People

The Company maintains a cybersecurity focused workgroup comprised of individuals who are trained, certified, and experienced in information and cybersecurity. Investment in, and ongoing assessment of our cyber skills is vital to the success of our cybersecurity function. Our employees work with business and information technology partners to implement and monitor the necessary layers of cyber defenses. Our personnel hold and maintain several IT industry standard security certifications, and actively pursue additional relevant intelligence and training. Several team members hold federal security "SECRET" level clearances, and actively participate in security forums, peer sharing groups, vendor partnerships, industry organizations, and state and federal avenues for information and intelligence sharing. This level of engagement and skills development enables the team to keep up with emerging threats, defenses design, and evolving technologies, such as with technologies that support AMF architectures. The Company also contracts as needed with experienced cybersecurity consulting firms, and engages objective assessors to perform security skills, design, and operational assessments as may be needed, and includes evaluations of our program compared to cybersecurity frameworks. By aligning the Company's strategic planning, portfolio management, individual and collaborative expertise, process excellence and commitment to investing in cybersecurity technology, the Company is well positioned to efficiently deliver and operate AMF in a cohesive manner that provides benefits for customers and addresses the Company's operational needs.

D. Process

Our Company employees leverage our internal security policies, standards methodologies, and procedures. These internal elements are derived from security best practices from a variety of proven sources, congruent with the relevant security requirements and nature of the assets/information to be protected, such as AMF. For example, the Company's cyber security program is not only well rooted in the National Institute of Standards and Technology (NIST) security standards, but also has benefited from ongoing assessments against other mainstream cybersecurity frameworks. Our cybersecurity team continually reviews and updates our Enterprise Security Standards to ensure congruence with NIST cybersecurity framework, and continues to look to best practice guidance for novel and effective ways to protect the company's assets from current and emerging threats.

E. Technology

Our Company has a strong commitment to investing in cybersecurity technology to support its defenses in depth. Along with the technology investments such as AMF that enable enhancements in areas such as improved reliability, customer satisfaction, communications, and mobility, the Company's cyber defenses must keep pace. With our qualified employees in place, who develop and follow strong and proven processes aligned to best practices, the functional and security technology can work together to provide secure results.

F. Purpose

When evaluating the risk and possible repercussions of a cybersecurity event, the Company will consider not only the potential impact to the flow of power to customers, but also the intended flow of data through the Company's system(s). Security and privacy recommendations will be designed to provide an acceptable level of protection for the continued confidentiality, integrity, and availability of the data that is stored, processed, and transmitted through the system, as well as the Company's continued ability to control the flow of power to customers. The likelihood that any potential adversary will attack the Company's AMF is dependent upon three general areas; desire to attack the system, the capability to conduct an attack, and the opportunity to attack. The desire to attack is based on the overall system awareness of the attacker and the perceived value of the information stored, processed, or transmitted over the Company's data paths. If a potential attacker determines that the value of the data warrants an attack, they must develop the capability to launch an attack, and to do so, they must be presented with the opportunity to launch an attack.

G. Organizational Commitment

PPL has enterprise-wide operating processes in place to ensure reliability and a robust security environment which will be used for AMF. Figure G1 identifies the relevant internal organizations and a list, albeit not exhaustive, of their responsibilities with respect to AMF cybersecurity and overall responsibility for reliability.

Figure G1: Organization Cybersecurity Responsibilities

Responsible Business Group	Responsibilities
Please identify responsible group	• Primary responsibility for secure, reliable operation of the AMI System including security of the smart meters • Total system and security responsibility and accountability • Disaster Recovery and Business Continuity Planning • Asset Identification and Management
Human Resources/ Physical Security	Personnel: • Screening, qualification, and requalification • Background Checks • Training • Access Control • Physical Security requirements
Cybersecurity Group	• Data Loss Prevention • Anti-Malware Management • Perimeter & Remote Access Protections • Encryption • Logical Access Controls/Identity Management • Password Management • Intrusion Detection • Incident Detection • Vulnerability Scanning & Remediation • Penetration Testing/Security Risk Assessment • Secure Code Reviews • System Hardening • Distributed Denial of Service (DDoS) protections • Disaster Recovery and Business Continuity Planning • Security Education, Awareness and Training • Security Patch Management • Cybersecurity Incident Response • Vendor Security Assessment • Other focus areas identified as needed

H. Approach to Cybersecurity

To ensure cybersecurity risks are adequately addressed, the Company will utilize its project management methodology to aid in creating cybersecurity controls, processes, and procedures. This process is a risk management-based approach for identifying, quantifying, and mitigating risks throughout a project' s lifecycle. This approach enables the Company to understand and manage the threats and risks in its current operations, as well as to identify potential future risks and develop appropriate mitigation plans. The way the cybersecurity and data privacy components integrate with the AMF lifecycle process is included in Figure G2.

Figure G2: PPL Project Management Methodology Process

DEFINITION	DISCOVERY	DESIGN	DEVELOPMENT
- Establish documentation repository - IT governance approval process for definition phase	- Initial security assessment - Create functional requirements document: detail scope, specifications, use cases, management controls, personnel and training, security perimeters, incident reporting, response planning, recovery plans	- Review design w/ technology and strategy team - Manage issues and risks - Create test plans: unit, systems and stress test - Create or revise security assessment	- Finalize operations and maintenance manual - DR, backup, recovery, etc. - Create production deployment plan and operational readiness assessment: Security risk assessment, Vulnerability scanning Penetration testing, Secure code reviews - Create training plan and training materials if applicable - Create business continuity plan - Conduct pre- deployment business continuity test - Manage issues and risks

DEPLOYMENT	DEBRIEF	SUPPORT
- Manage issues and risks - Employee training - User account/access provisioning - Operator acceptance testing	- Document lessons learned	- System monitoring and management - Incident response - Configuration management - System audit

DEPLOYMENT	DEBRIEF	SUPPORT
- Security verification testing - Security operations implemented		- Security risk assessments - Disaster recovery exercises - User access maintenance - System decommissioned /disposition: Sensitive data destruction, System disposition, Operations and policy updates

I. *Vendor Cybersecurity Requirements Assessment*

AMF system equipment provided by third party vendors will be evaluated for compliance with cybersecurity requirements derived from the Company's Enterprise Security Standards and appropriate industry security standards and frameworks. This evaluation process will continue throughout the development lifecycle, and is outlined in Figure G3 below.

Figure G3: Vendor Cybersecurity Requirements Assessment

Review Proposed Hardware	Hardware Recommendations
• Evaluate Hardware for Applicability to the Defined Requirements • If Applicable, Evaluate Hardware Capability for Compliance with Requirements • Identify Any Hardware Requirement Deficiencies	• Evaluate Hardware Deficiencies and Identify Possible Mitigating Factors • Rate Hardware Requirements Compliance as 'Compliant Out of the Box', 'Mitigation s Required for Compliance' or 'Non-Compliant, No Mitigations Possible' • Identify if Alternative Hardware Solutions are Needed • Develop Recommended Actions for Consideration Prior to Implementation

Any changes to the hardware solutions planned will be evaluated via this process, and recommendations will be presented prior to implementation. In the event that a component cannot meet the Company's cybersecurity requirements, we will evaluate the risk and its mitigation options as part of the Company's Security Risk Assessment process.

J. Cybersecurity Operations

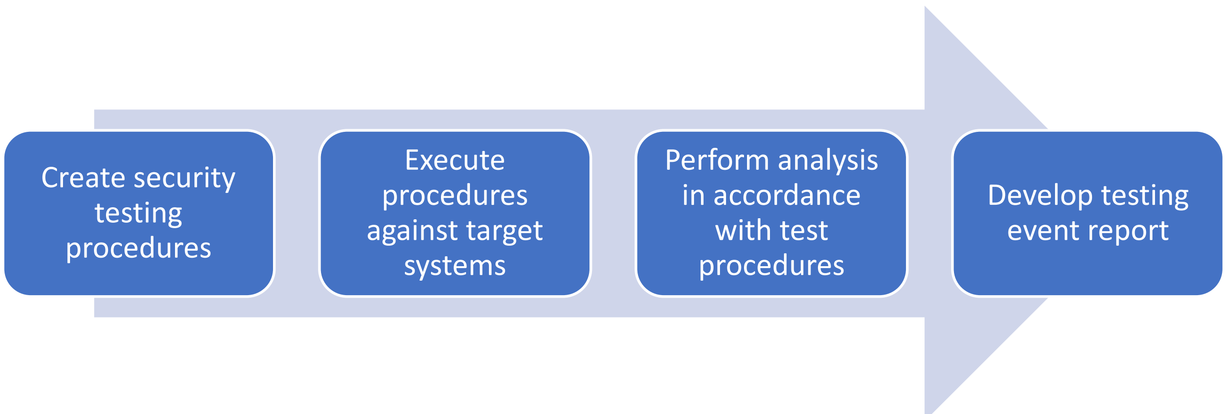
The project management methodology extends to operational support of the cybersecurity environment. To that end, the AMF program will implement monitoring, logging, and incident reporting. The Company plans to implement intrusion detection systems and processes to provide alarming and notification of security events. Additionally, the Company's Computer Security Incident Response Team (CSIRT) will utilize existing tools, capabilities and procedures to provide timely response and recovery from security incidents. Upon notification that a security incident may have occurred, or is likely to occur, an alert is sent to the Executive Crisis Team (ECT); the ECT assesses the incident and, if necessary, assembles a CSIRT Team comprised of subject matter experts relevant to the specifics of the incident. The response team prepares an action plan, mitigates the security incident, and assembles documentation in accordance with the Company incident response procedures. These procedures will be reviewed and updated, if necessary, during the AMF cybersecurity design process. The Company currently has in place policies and procedures for managing user access, performing system audits, reviewing system logs, etc. to maintain cybersecurity vigilance. These policies and procedures will be augmented, if need be, to address any new or unique risks or issues associated with AMF. In addition, updates and patches to infrastructure devices and systems will be managed using the existing Configuration and Change Management Standard. This standard requires that upgrades, both major and minor, must include a security risk assessment prior to operational implementation.

The Company has in place both Disaster Recovery (DR) and Business Continuity (BC) plans that are regularly tested by means of DR and BC drills. These plans will be updated to encompass the AMF systems, and DR and BC drills will be conducted as part of operational readiness testing to verify plan effectiveness.

K. Risk Assessment, Testing, and Quality Assurance

AMF will create a Risks Register document, and any cybersecurity or data privacy related risks will be entered and managed accordingly. Test plans will be developed and executed to ensure that cybersecurity functions operate as designed. Figure G4 below depicts the Company's approach to system security testing.

Figure G4: System Security Testing



The cybersecurity team will be responsible for identifying and mitigating security risks and ensuring that the fielded systems meet the requirements and configuration as prescribed in the Company's Enterprise Security Standards, and include the following activities:

Security RiskAssessments

The Security Risk Assessment ("SRA") is a review that provides a baseline for the development of risk mitigation actions needed to protect the utility' s systems and environments. It is conducted using a well-defined set of information security standards, guidelines, and industry best-practices. The SRA activities will include: 1) System characterization (both operational and technical) , 2) Threat identification, 3) Vulnerability identification, and 4) Risk Determination/Valuation.

Using the guidelines provided by Federal Information Processing Standards ("FIPS") and NIST among others, the Security Risk Assessment will determine the potential impact of threats and vulnerabilities to the Confidentiality, Integrity and Availability ("CIA") of AMF's data and systems. This impact determination, combined with an assessment of threat probability, will form the basis for risk-weighted mitigation planning.

Vulnerability Scans

Vulnerability scans are conducted on the operational system, prior to deployment and post-deployment, to ensure the system adheres to the cybersecurity design. This quality assurance check is conducted using automated tools and manual scanning to verify configuration items such as: firewall rules, port configurations, password structure and complexity, user authentication and access permissions, etc.

Penetration Testing

Penetration testing is the best indicator of real-world vulnerability to cyber-attacks, both internal and external. Conducted by objective, experienced and knowledgeable "Certified Ethical Hackers," this activity determines the degree to which the systems are vulnerable to a variety of cyber-attacks. The team will conduct a series of targeted attacks from the smart meters to the AMF systems and document the gaps and vulnerabilities discovered. These gaps and vulnerabilities will be managed and/or mitigated.

L. Data Privacy

One of the first steps of the initial security assessment is to determine the type of data and information that requires protection so that the appropriate security controls are planned in advance. For AMF, the "Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and the Smart Grid" recommendations will be followed and conduct a privacy impact assessment (PIA) before any deployment. The PIA will help the project team with the following:

Identifying and managing privacy risks: Conducting an exercise to identify potential privacy risks early in the project demonstrates good governance and business practice.

Meeting legal requirements: Conducting the assessment provides the opportunity to ensure that any privacy risks are identified early, and thereby implementing the appropriate controls that will allow for ensuring the implementation adheres to legal requirements. This also applies when engaging a third party, where the data owner is responsible for ensuring the appropriate controls are in place to protect personal data.

M. Standards

As noted, the AMF Project will leverage emerging interoperability and security standards, including, but not exclusive to those developed by the NIST. Throughout the AMF Project lifecycle, security requirements, processes and procedures will leverage the following standards:

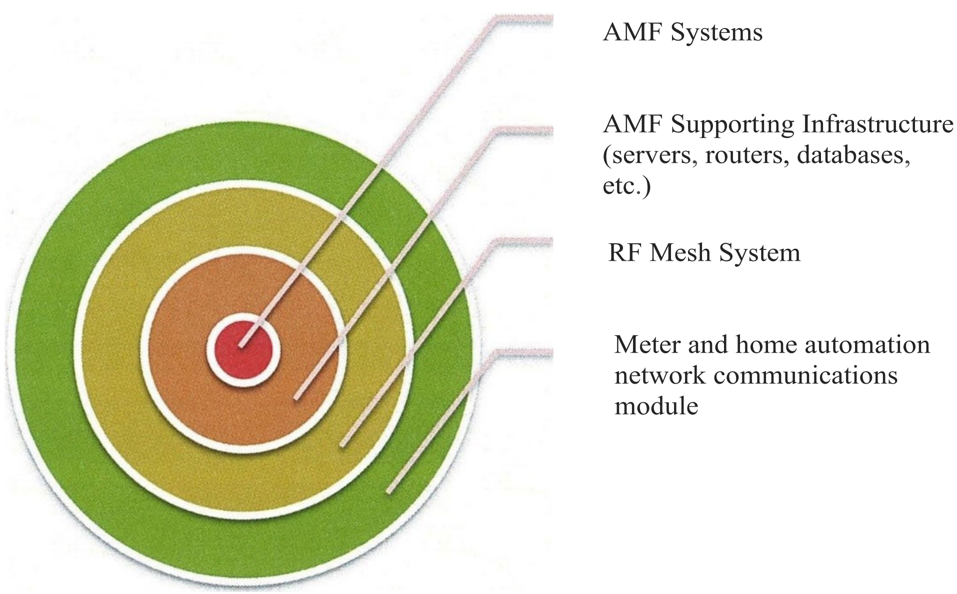
Security Requirements Creation	NIST SP 800-53 *"Recommended Security Controls for Federal Information Systems and Organizations"*
Security Risk Assessment Methodology	NIST SP 800-30 *"Risk Management Guide for Information Technology Systems",* NIST SP 800-60 *"Guide for Mapping Types of Information and Information Systems to Security Categories",* and FIPS 199 "*Standards for Security Categorization of*

	Federal Information and Information Systems"
Vulnerability Identification	NISTIR 7628 *"Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and Smart Grid"*
Security Testing Methodology	NIST SP 800-115 *"Technical Guide to Information Security Testing and Assessment"*

N. Impact on Overall AMF Security

Protection of AMF is accomplished via multiple layers of network, personnel, and physical security barriers. If compromises to the system were to occur, the location of that compromise would determine the impact on the overall AMF security. While there are numerous endpoint devices in the AMF network, compromise of one device would have a lower overall impact than a compromise of the AMF Systems. These levels of compromise are represented in Figure G5, with red representing the highest potential impact.

Figure G5: Potential Impact to Overall Grid Security



AMF will be implemented with cybersecurity and data privacy as a cornerstone. The increased scrutiny of the AMF systems and network, the interfaces with new smart devices, and reviews and updates to existing policies, procedures, and operational concepts is expected to maintain the overall security posture of AMF.

Attachment H
Redacted

<u>AMF Benefit-Cost Analysis (BCA) Spreadsheet and Narratives</u>

CONFIDENTIAL

The Company provided AMF BCA Analysis Spreadsheet as an Excel version and the Narratives as a PDF file.

As permitted by the Public Utilities Commission Rule 810-RICR-00-00-1-1.3(H)(3) and Rhode Island Gen. Laws § 38-2-2(4)(A), -(B), the Company is seeking confidential treatment of the AMF BCA Spreadsheet and Narratives.

Attachment I

ACRONYM LIST

Acronym	Description	Acronym	Description
ACE	Affordable Clean Energy Security Act of 2014	**CAPEX**	Capital Expenditure
ACEEE	American Council for an Energy-Efficient Economy	**CCA**	Community Choice Aggregator
ADMS	Advanced Distribution Management System	**CEP**	Customer Engagement Plan
AES	Advanced Encryption Standard	**CMS**	Centralized Meter Services
AESC	Avoided Energy Supply Cost	**CO2**	Carbon Dioxide
AMF	Advanced Metering Functionality	**COR**	Cost of Removal
AMI	Advanced Metering Infrastructure	**CP**	Customer Portal
AMI/AMFaaS	Advanced Metering Infrastructure/Functionality as a Service	**CPP**	Critical Peak Pricing
AMO	Advanced Metering Operations	**CPR**	Critical Peak Rebate
AMR	Automated Meter Reading	**CSS**	Customer Service System
ANSI	American National Standards Institute	**CVR**	Conservation Voltage Reduction
API	Application Programming Interfaces	**CX**	Customer Experience
AQL	Acceptance Quality Limit	**DART**	Days Away, Restricted, or Transferred
ART	Agile Release Train	**DCFC**	Direct Current Fast Charging
ASA	Amended Settlement Agreement; Average Speed of Answer	**DER**	Distributed Energy Resources
ASQ	American Society of Quality	**DERMS**	Distributed Energy Resource Management System
B/C	Benefit to Cost Ratio	**DG**	Distributed Generation
BCA	Benefit Cost Analysis	**DMV**	Division of Motor Vehicles
BOT	Business Ownership Team	**DOE**	Department of Energy
BTM	Behind The Meter	**DOT**	Department of Transportation
C&I	Commercial and Industrial	**DPUC**	Division of Public Utilities and Carriers
DR	Demand Response	**GB**	Green Button
DRIPE	Demand Reduction Induced Price Effect	**GBC**	Green Button Connect
DSM	Demand-Side Management	**GIS**	Geographic Information System
EDI	Electronic Data Interchange	**GMP**	Grid Modernization Plan
EE	Energy Efficiency	**GPS**	Global Positioning System
EEI	Energy Efficiency Initiative	**GWH**	Gigawatt-hour
EH	Electric Heat Pumps	**HAN**	Home Area Network
EIA	Energy Information Administration	**HER**	Home Energy Report
EMF	Electromagnetic Frequency	**HES**	Head End System
EPRI	Electric Power Research Institute	**HVAC**	Heating Ventilation Air Conditioning
ERT	Encoder Receiver Transmitter	**ICAP**	Installed Capacity
ES	Energy Storage	**ICNIRP**	International Commission on Non-Ionizing Radiation Protection
EV	Electric Vehicle	**IEEE**	Institute of Electrical and Electronic Engineers
FAN	Field Area Network	**IEI**	Edison Foundation Institute for Electric Innovation
FAQ	Frequently Asked Questions	**IHD**	In-Home Device
FAT	First Article Testing	**IOU**	Investor-Owned Utility
FCC	Federal Communications Commission	**IP**	Internet Protocol
FCS	Field Collection System	**ISO NE**	Independent System Operator New England
FERC	Federal Energy Regulatory Commission	**ISR**	Infrastructure, Safety, and Reliability Plan
FLISR	Fault Location Isolation and Service Restoration	**IT**	Information Technology
FTE	Full-Time Employee	**JBO**	Job Behavior Observation
G32	Rhode Island Energy Large Demand Commercial &	**JTAG**	Joint Test Action Group
KU	Kentucky Utilities	**NIST SP**	National Institute of Standards and Technology Special Publication
KVAR	Kilo Volt Ampere reactive	**NITS**	Network Integration Service Rate
KW	Kilowatt	**NOC**	Network Operations Center
KWH	Kilowatt-hour	**NOx**	Nitrogen Oxide
KY	Kentucky	**NPP**	Non-Regulated Power Producer
LED	Light-Emitting Diode	**NPV**	Net Present Value
LMI	Low and Moderate Income	**NY**	New York
LG&E/KY	Louisville Gas and Electric Company/Kentucky Utilities	**O&M**	Operating and Maintenance
LNG	Liquid Natural Gas	**OER**	Office of Energy Resources
LTC	Load Tap Changing/Changer	**OMS**	Outage Management System
LTE	Long-Term Evolution	**OPEX**	Operating Expense
MaaS	Meters as a Service	**OTA**	Over The Air
MDM	Meter Data Management	**PA**	Pennsylvania
MDMS	Meter Data Management System	**PI**	Program Increment
Mesh IP	Internet Mesh Telecommunications Network	**PMO**	Program Management Office
MRP	Multi-Year Rate Plan	**PPL**	Pennsylvania Power & Light
MTU	Meter Transmission Unit	**PPL EU**	Pennsylvania Power & Light Electric Utilities
NaaS	Network as a Service	**PST**	Power Sector Transformation
NERC	North American Reliability Corporation	**PUC**	Public Utilities Commission
NG	National Grid	**PV**	Photo Voltaic
NIC	Network Interface Card	**RACI**	Responsible, Accountable, Consulted, and Informed
NIEHS	National Institute of Environmental Health Services	**RAM**	Random Access Memory
NIST	National Institute of Standards and Technology	**RD&D**	Research, Development and Demonstration
REGP	Renewable Energy Growth Program	**SWSN**	Statewide Shared Network
RF	Radio Frequency	**T&D**	Transmission and Distribution
RGGI	Regional Greenhouse Gas Initiative	**TDI; TD&I**	Technical Development and Improvement
RI	Rhode Island	**TMS**	Transmission Management System
RIE	Rhode Island Energy	**TOU**	Time of Use
RIGL	Rhode Island General Law	**TSA**	Transition Service Agreement
RIPUC	Rhode Island Public Utilities Commission	**TVR**	Time-Varying Rate
RRA	Resilient Rhode Act	**UAT**	User Acceptance Testing
RTP	Real-Time Pricing	**UL**	Underwriters Laboratories
SAIFI	System Average Interruption Frequency Index	**UTC**	Unable to Complete
SCADA	Supervisory Control and Data Acquisition	**V2G**	Vehicle to Grid
SCT	Societal Cost Test	**VEE**	Validation, Estimation, & Editing
SECC	Smart Energy Consumer Collaborative	**VMT**	Vehicle Miles Traveled
SI	System Integration	**VPP**	Variable Peak Pricing
SLA	Service Level Agreement	**VVO**	Volt-Var Optimization
SME	Subject Matter Expert	**WACC**	Weighted Average Cost of Capital
SP	Supplier Portal	**WAN**	Wide-Area Network