

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

	)	
Petition of NSTAR Electric Company d/b/a	)	
Eversource Energy for Approval of its 2022	)	D.P.U. 21-80
to 2025 Grid Modernization Plan	)	
	)	
	)	
Petition of Massachusetts Electric Company	)	
and Nantucket Electric Company, each d/b/a	)	D.P.U. 21-81
National Grid for Approval of its 2022 to	)	
2025 Grid Modernization Plan	)	
	)	
	)	
Petition of Fitchburg Gas and Electric Light	)	
Company d/b/a Unitil for Approval of its	)	D.P.U. 21-82
2022 to 2025 Grid Modernization Plan	)	
	)	

**JOINT COMMENTS OF MASSACHUSETTS ELECTRIC COMPANY AND
NANTUCKET ELECTRIC COMPANY, each d/b/a NATIONAL GRID, NSTAR
ELECTRIC COMPANY D/B/A EVERSOURCE ENERGY, AND FITCHBURG GAS
AND ELECTRIC LIGHT COMPANY D/B/A UNITIL IN RESPONSE TO THE
DEPARTMENT OF PUBLIC UTILITIES' JULY 15, 2025 TECHNICAL SESSION**

On October 7, 2022 and November 30, 2022, the Department of Public Utilities (the “Department”) issued orders approving the continuing and new grid modernization investments, including Advanced Metering Infrastructure (“AMI”) proposals, filed by Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid (“National Grid”), NSTAR Electric Company d/b/a Eversource Energy (“Eversource” or “NSTAR Electric”), and Fitchburg Gas and Electric Light Company d/b/a Unitil (“Unitil”) (National Grid, Eversource, and Unitil may hereinafter be referred to jointly as the “EDCs” or the “Companies”). D.P.U. 21-80-A/21-81-A/21-82-A (2022) (“Track 1 Order”); D.P.U. 21-80-B/21-81-B/21-82-B (2022) (“Track 2

Order”).¹ The Track 2 Order directed the EDCs to convene a stakeholder working group to address discrete issues related to implementation of the Companies’ AMI Plans and to file a final report on August 1, 2024. Track 2 Order at 326-329. In issuing its directives regarding the stakeholder working group, the Department reiterated that the process must not delay the implementation of the Companies’ proposed AMI investments. Id. at 325 (emphasis added). The EDCs filed the final AMI Stakeholder Group Report on August 1, 2024; the final AMI Stakeholder Group Report included consensus and non-consensus items.

The Department convened a technical session on May 6, 2025 to address non-consensus items arising from the AMI Stakeholder Working Group and statutory requirements set forth in An Act Promoting a Clean Energy Grid, Advancing Equity and Protecting Ratepayers, St. 2024, c. 239 (“2024 Climate Act”). The Department subsequently issued a memorandum on May 23, 2025 requesting additional comments from stakeholders and identifying next steps. The EDCs filed comments in response to the Department’s May 23, 2025 Memorandum on June 27, 2025 (the “June Joint EDC Comments”). The Department held a second technical session on July 15, 2025. On July 14, 2025, Mission Data, NRG Energy, and Vistra Corporation (the “Suppliers”) filed a presentation with the Department specifically to address the Supplier’s recommendation that the Department should direct the EDCs to develop capabilities to support settlement load by the end of 2026 (the “Supplier Presentation”). The Department issued a memorandum on July 17, 2025 providing an opportunity for final comments on the issues addressed at the July 15, 2025 technical session.²

¹ The Track 1 Order approved the Companies’ continuing grid modernization investments and the Track 2 Order approved the Companies’ new grid modernization investments, including AMI.

² The EDCs filed a motion for an extension of time to file these comments on July 21, 2025 that was granted by the Department on July 21, 2025; the extension of time was extended to all parties and/or stakeholders.

The EDCs were unable to fully respond to the Supplier Presentation at the July 15, 2025 technical session due to receipt of the Supplier Presentation less than one business day in advance of the session. Accordingly, the EDCs appreciate this opportunity to provide additional context regarding the benefits that their respective AMI Plans are providing and will provide to customers, and how the EDCs have planned to support more complex rate options, including time-varying rates (“TVR”).

As detailed below, the EDCs disagree with (1) the Supplier Presentation’s conclusions that ISO-NE Load Settlement was discussed “at length” in this proceeding; and (2) statements at the July 15, 2025 technical session that benefits associated with ISO-NE Load Settlement to enable complex supplier time varying rates (“TVR”) were relied upon to support approval of the EDCs’ individual AMI Plans.³ As described in more detail below, the Supplier Presentation cites only to a handful of questions during the evidentiary hearings in these matters but fails to reference the individual EDC AMI Plans that were approved, the Department’s Track 2 Order (which did not rely on benefits associated with complex TVR), or any of the extensive discovery in these proceedings.

A comprehensive review of the records in these proceedings makes clear that the AMI Plans were approved based on business case analyses that did **not** account for the costs necessary to enable ISO-NE load settlement or the benefits of enabling ISO-NE load settlement. Accordingly, any directive from the Department to make the additional investments necessary to allow for ISO-NE load settlement using interval data should only be made following consideration of a new business case analysis and based on the determination that the increased costs justify any

³ During the July 15, 2025 technical session comments were made that implied that the EDCs were failing to provide benefits proposed as part of the cost-benefit analysis relied upon by the Department in approving such plans. Such comments are unfounded, self-serving in regards to the suppliers’ business interests and contradictory to the Department’s Track 2 Order.

potential benefits to customers. This additional process not only is necessary, but is reasonable and consistent with the Department's own recognition that "cost and benefit estimates may need to be revised and refined during the development and implementation of a company's grid modernization plan." Track 2 Order at 223, citing D.P.U. 12-76-C at 13; see also D.P.U. 20-69-A at 30-31. The need for this capability to support interval load settlement was not known when the Companies filed their AMI Plans (and related business case analyses) in 2021. Therefore, it is appropriate for the Department to review additional information regarding the associated costs and benefits before directing the EDCs to fully develop these capabilities. The EDCs also note that the Department issued an order on August 1, 2025 suspending docket D.P.U. 19-07, the Department's investigation into initiatives to promote and protect consumer interests in the retail electric competitive supply market. The Department explained that it was suspending the proceeding in response to H.4144, An Act Relative to Energy Affordability, Independence, and Innovation that "will require substantial reforms to the residential competitive supply market...". D.P.U. 19-07, at 1. It is not known if those reforms would impact TVR offerings in the residential competitive supply market. This additional "unknown" further supports the EDCs' position that TVR not be expedited and instead that the approved-AMI plans be implemented according to the carefully developed timelines presented in these proceedings.

Below, the EDCs recount the significant progress achieved by the AMI Stakeholder Working Group and the EDCs' progress in implementation of the approved-AMI plans, and confirm the benefits that have begun to accrue to customers based on the *approved* AMI plans as supported by the business cases developed and investigated in D.P.U. 21-80, D.P.U. 21-81, and D.P.U. 21-82. Lastly, each EDC addresses the benefits expected under these approved AMI Plans that were presented to support the Department's Track 2 Order.

I. The AMI Stakeholder Group Resulted in Significant Consensus and/or Lack of Opposition

It is important to reiterate that the AMI Stakeholder Group process resulted in consensus on many of the topics discussed and that the remaining issues for resolution are discrete and do not undermine the significant progress that has occurred. The Track 2 Order directed the EDCs to facilitate the AMI Stakeholder Group to address four issues: (1) customer and third-party access to customer usage data; (2) customer education and engagement; (3) billing of TVR offered by competitive suppliers; and (4) AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products. Track 2 Order at 327. In the Final AMI Stakeholder Group Report filed in August 2024, the EDCs included a consensus matrix that highlights the areas where stakeholders were able to reach consensus and the non-consensus items that require additional Department input to reach resolution.⁴ To reach consensus, where feasible and appropriate, the EDCs have incorporated stakeholder feedback. For example, the stakeholders discussed and reached general consensus on the framework for billing supplier TVR.⁵

While the stakeholders and EDCs have not reached consensus regarding all aspects of providing data to third-party suppliers and/or municipal aggregators, the EDCs have engaged on these issues extensively and in good faith. The unresolved topics are not points of major dispute, but rather topics that require Department guidance regarding data and privacy policy. In addition to the AMI Stakeholder Working Group meetings, the EDCs also facilitated technical workshops to address sub-topics and supported stakeholder requests for additional Department guidance. The EDCs have engaged in these discussions and this additional work while moving forward with

⁴ Final AMI Stakeholder Working Group Report, Attachment G.

⁵ Final AMI Stakeholder Working Group Report, Attachment G, at 2.

implementation of the AMI Plan components that enable deployment of AMI meters and the associated customer benefits, and have begun deploying meters. The EDCs have continued to work towards achieving the timelines proposed in these dockets and remain on track to do so. This demonstrated commitment ensures that the EDCs make progress towards providing customers with the benefits associated with AMI and achieving the Department's objectives in approving the AMI plans.

II. The EDCs are on Track to Deliver their AMI Plans as Presented, including Customer Benefits

The Department approved each EDC's AMI Plan based on its evaluation of an EDC-developed business case analysis that compared estimated costs with estimated benefits. Track 2 Order at 238, 258, 277. This business case analysis presented the costs and benefits of the proposed AMI Plan over a specific timeframe (see, e.g., D.P.U. 21-80, Exh. ES-AMI-4 (Rev.)). As described in the EDC-specific sections below, each company has identified specific costs and benefits associated with its AMI Plan and has provided a timeline for investments. The timeline will determine when benefits materialize. During the AMI Stakeholder Working Group and in the subsequent Department-led technical sessions, the EDCs provided updates on their progress in implementing the AMI Plans. None of the EDCs has substantially deviated from its proposed timeline. For example, Eversource's AMI's technical support went live in July 2025, and National Grid and Unitil are installing meters at customers' premises.⁶ Accordingly, the EDCs are on track to begin delivering benefits to customers that are or will include increased access to outage data and more efficient outage restoration, remote metering capabilities (i.e., remote connection or disconnection, subject to Department regulations on termination), enhanced distribution system

⁶ See Joint EDC Presentation filed on April 29, 2025 providing an update on each EDCs' AMI Plan deployment for a more detailed update by company.

operations, and improved load forecasting. These benefits are separate and distinct from benefits that supplier TVR *could* provide in the future and these EDC-identified benefits are the ones the Department relied upon in reaching its determination to approve the AMI Plans.

The EDCs do not dispute that TVR has the potential to provide benefits to customers. However, TVR is just one benefit that is expected to result from the deployment of AMI meters and was not, in the initial GMP plans, identified or expected to begin in 2026. The timelines developed by the EDCs in support of their respective AMI Plans did not anticipate TVR benefits until 2029 (Eversource) and 2027 (National Grid). Unitil's plan did not provide a specific timeline for implementation of TVR (or any other form of time of use rates), with the expectation that further scoping would be required. As discussed in more detail below, each of the EDCs recognized that there would be benefits associated with TVR following deployment of AMI meters but also confirmed that additional Department-led process, including an in-depth investigation of the costs and benefits associated with TVR, was necessary before TVR could be designed and deployed for residential customers. Similarly, the Department reiterated that it would address TVR in a separate investigation. Track 2 Order at 327, nt. 136; D.P.U. 14-04-D at 8. Accordingly, the benefits directly attributed to TVR included in the business case analyses were modest due to the expectation of future investigations.

a. The Department has Consistently Indicated that Additional Process Would Occur to Address TVR

In parallel with its initial grid modernization investigation (D.P.U. 12-76), the Department conducted a proceeding to consider an appropriate framework for implementation of TVR (D.P.U. 14-04). As part of that investigation, the Department determined that TVR would require development of a uniform, statewide data access plan. In D.P.U. 15-122, the Department stated, when addressing the EDCs' advanced metering functionality ("AMF") proposals, that "data access

is crucial for third-parties and competitive suppliers to participate in the modernized grid and provide the benefits of TVR.” D.P.U. 15-122, at 128 citing D.P.U. 12-76-B at 34. The Department also noted that establishing standardized policies regarding third-party access to interval usage data (both customer-specific and aggregated) will optimize the benefits that consumers can realize from dynamic pricing. Id. at 128. The Department, having identified several issues that affect competitive suppliers’ and municipal aggregators’ interests and ability to offer dynamic pricing products, including access to customer data, billing limitations, and the uncertainty of customer willingness to participate in dynamic pricing products, determined that, as customers migrate from basic service to competitive supply alternatives such as municipal aggregation, it would need the certainty of widespread adoption of dynamic pricing products from the competitive market to maximize the benefits of the deployment of AMF. Id. at 128-129, 136.

Consistent with these findings, the Department identified the need for the EDCs and other stakeholders to develop a uniform statewide data access strategy. Id. at 129, 136. The Department found that a high level of participation in dynamic pricing, such as TVR, is needed to maximize the benefits of customer-facing technologies as a growing number of the EDCs’ customers receive competitive supply. Id. at 136. Specifically, the Department determined that the ability of the competitive market to develop and offer dynamic pricing products depends in large part on: (1) the capability of the EDCs to bill for a variety of dynamic pricing products; (2) the ability of suppliers to access interval usage data; and (3) customers to be engaged and knowledgeable about energy pricing. Id. at 136-137. In light of these issues, the Department stated its intention to investigate the most appropriate ways to enable competitive supply customers, including municipal aggregation participants, to participate in dynamic pricing programs and that the focus of its investigation will be specific solutions in metering, data access,

and billing that would enable customers on competitive supply to participate in dynamic pricing programs as effectively as customers on basic service. Id. at 137.

Consistent with the Department's stated intentions and directives, the EDCs have been active participants in the stakeholder process to develop a uniform statewide data access strategy. This data access strategy has not been finalized and in fact, is one of the items for which Department guidance was requested.⁷ The EDCs did not develop TVR proposals as part of their filings in this docket because it was premature pending this additional Department process and full deployment of AMI meters (initial meters for National Grid and Eversource, and replacement meters for Unitil). Final design of any TVR proposal depends on the Department's guidance regarding a uniform, statewide data access strategy and TVR rate design.

b. The EDCs' AMI Plans were not Supported by Benefits Associated with Complex Supplier TVR

As noted above, the issue of load settlement capabilities to support complex supplier TVR is a non-consensus item. Through the stakeholder group process,⁸ the EDCs have come to understand two critical points: 1) the importance to suppliers of interval-based load settlement for all customers; and 2) their downstream load settlement system limitations on using AMI interval data for each customer. The Eversource and National Grid AMI Plans contemplated basic TVR following full meter deployment (2029 for Eversource and 2027 for National Grid), and an extensive Department-initiated investigation of TVR prior to the respective launch dates to further define system requirements. Therefore, while this issue has become contentious, it is important

⁷ See AMI Report at 20.

⁸ The Companies note that the suppliers that intervened as full parties in D.P.U. 21-80/21-81/21-82 did not raise these issues during the pendency of those proceedings, despite having the opportunity to issue discovery, provide witness testimony, cross-examine the Companies' witnesses and file briefs supporting their positions and recommendations.

to note that the EDCs' position is not inconsistent with what was proposed (and approved) in these proceedings. As the Companies confirmed in the June Joint EDC Comments, the business case analysis submitted by each EDC in support of its respective AMI Plan did not include the costs or benefits associated with the investments necessary to address the downstream load settlement enhancements that suppliers consider a prerequisite for TVR.

Following the deployment of AMI meters, data sufficient to support TVR will be available. As a result, the EDCs' AMI Plans were developed with the premise that simple TVR would become available with the AMI meter deployment as an initial step. Due to the uncertainty and need for additional Department guidance through the additional process described in Section II(a), above, the EDCs included conservative estimates of customer benefits associated with TVR offered by the Companies. The initial (and more substantial) benefits associated with the approved AMI Implementation Plans are tied to increased capabilities associated with outage reporting, remote meter capabilities, data sharing, and system monitoring and advanced planning. These benefits are being accrued to customers and will continue to accrue over the investment period. Consistent with the timelines presented in this proceeding, the initial TVR benefits also continue to be expected following deployment of AMI meters, as will be explored in the future TVR investigation(s) identified by the Department. Track 2 Order at 327, nt. 136; D.P.U. 14-04-D at 8.

III. Company-Specific Responses to the July 15, 2025 Technical Session Presentations and Comments

As discussed above, the EDCs disagree with the Supplier Presentation conclusion that the Companies are failing to deliver the benefits presented in this proceeding. Below each of the EDCs provides further support based on its representations in these proceedings.

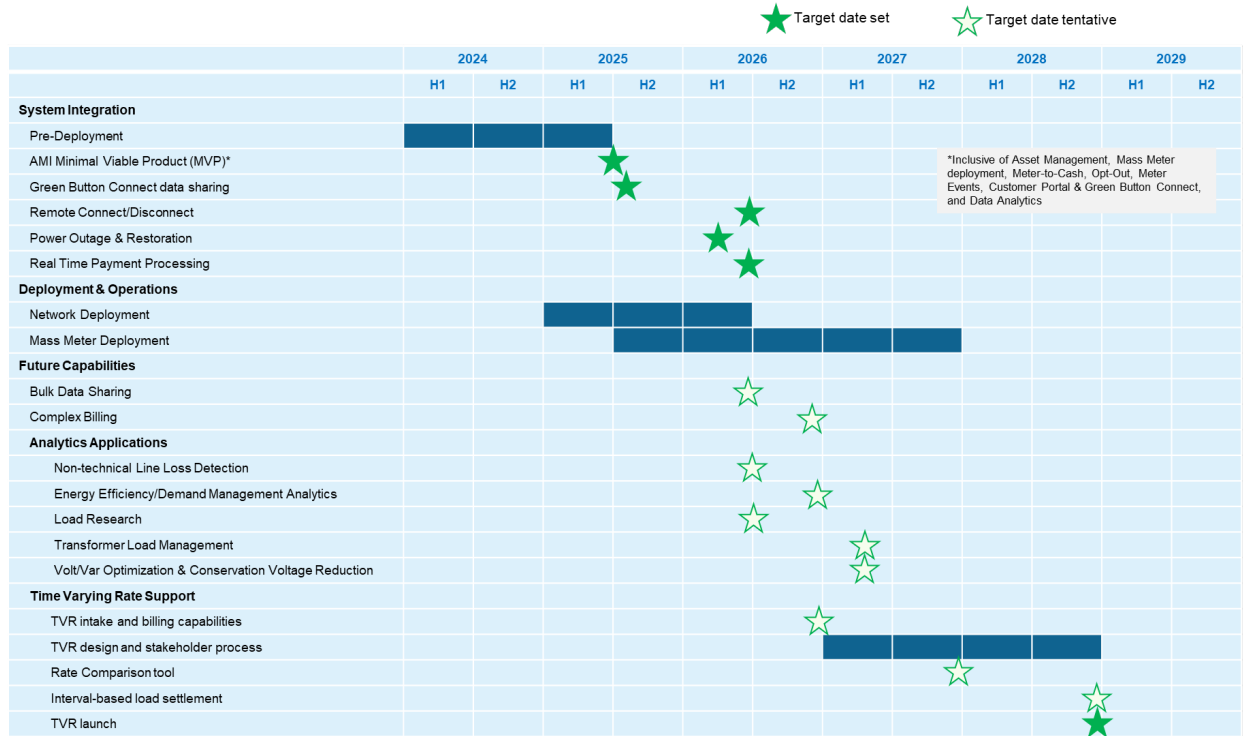
a. Eversource Energy

As detailed above, the EDCs are on track to deliver the benefits that were proposed and that formed the basis of the Department's approval of the Companies' AMI Plans. In its approved AMI deployment plan, Eversource committed to a TVR launch date of the first quarter of 2029.⁹ Eversource has not wavered in its commitment to that target date. NSTAR Electric is confident in its ability to launch TVR on the committed timeline, including load settlement upgrades to permit the intake of interval data for all customers with AMI meters. However, as detailed below, these load settlement upgrades were not included in the business case analysis reviewed by the Department in this proceeding and therefore would require additional Department review and approval before Eversource moves forward (i.e., the Department must review the upgrades and confirm that such upgrades are prudent and cost-justified).

The 2029 TVR launch date was part of Eversource's AMI timeline that has been developed to deliver the series of compounding benefits as cost-efficiently as possible, and in a manner that helps customers experience tangible enhancements they value as quickly as possible after receiving their AMI meter. As the table below illustrates, NSTAR Electric will be delivering a broad set of benefits that expand direct customer communications and alerts, offer new insights and recommendations, allow customers to access and share their data, enhance outage communications and restoration, improve the efficiency of the grid, enable an expanding portfolio of analytics applications, and introduce TVR and assist customers in navigating their rate options. As of the date of these comments, Eversource remains on track to deliver each of the benefits within the committed timeframe in its approved AMI Plan.

⁹ D.P.U. 21-80, Exh. ES-AMI-4 (Rev.) at 24.

Table 1. Eversource Energy AMI Benefits Timeline



Eversource continues to support implementation of TVR on a schedule that is consistent with its approved timeline (versus on an expedited basis) for several reasons:

1. Eversource anticipates that the Department, consistent with its earlier determinations, will conduct a separate investigation regarding TVR design and implementation across the Commonwealth; this process is a prerequisite to the prudent rollout of TVR;¹⁰
2. In order to achieve wide customer acceptance and maximum system benefit, the design and implementation of TVR should be informed by careful analysis of a sufficient history of customer interval usage data. Adequately robust data will not be available for the majority of Eversource customers before 2027, meaning that the analysis, informed stakeholder process and launch could not be realistically achieved prior to 2029.
3. Successful rollout of TVR will require extensive customer engagement and education campaigns. If TVR and the accompanying education are rolled out while many customers still do not have AMI or adequate usage history to evaluate their options, the messages will be confusing and potentially disengaging.
4. The full AMI deployment plan requires a team of internal and external experts in systems, processes and hardware to first build the technology foundations and then develop the

¹⁰ See D.P.U. 21-80, Exh. AC 1-9 (explaining that TVR options cannot be offered prior to full deployment of Eversource's new CIS and only following the Department proceeding for the design and deployment of TVR offerings).

customer- and grid-facing capabilities that produce the tangible benefits. The progression of investments reflects the finite capacity of the core team of experts. It also ensures that prerequisites are in place prior to the launch of each new capability. A TVR launch will not be possible without first implementing customer data sharing, AMI-interval based load research analytics, TVR billing and rate intake capabilities, and a rate comparison tool for customers.

Eversource is moving forward (together with National Grid and Unitil) with plans to enable broad customer usage data sharing. Subject to resolution of the issues presented to the Department for guidance and clarification, Eversource is building the capabilities necessary to accommodate this data access. Eversource's extensive plans for customer engagement and education have also begun in order to coincide with commencement of meter deployment (in July 2025). These customer engagement and education plans were presented to the AMI Stakeholder Group and did not result in any areas of non-consensus or concern.

On the topic of TVR billing for competitive suppliers, Eversource committed to activating the ability to intake and bill supplier TVR rates that correspond to standard parameters (agreed-upon by the other EDCs and stakeholders), and to accommodate rates proposals outside of those parameters with bill-ready billing. That proposal was offered to the stakeholder group in late 2023 with an implementation target date of the end of 2026, assuming Department guidance was received in response to the Final AMI Stakeholder Group Report that was filed in August 2024. However, due to the ongoing Department process including the recent technical sessions, the EDCs have not yet been able to commence the EDI working group discussions necessary to accommodate TVR rate uploads and therefore an end-of-2026 timeline may no longer be feasible. Nonetheless, Eversource remains committed to activating the TVR capabilities of its modernized customer information system ("CIS") as soon as is technically feasible.

While its AMI Plan did not rely on substantial benefits associated with TVR to support its business case, Eversource is not opposed to consideration of these system enhancements that

would address the now identified constraint on using AMI interval data in Eversource's separate load settlement process. This constraint was not identified until Eversource was engaged in working group discussions with suppliers regarding their data needs for launching TVR. It had not been identified prior to that because a review and potential overhaul of Eversource's load settlement system had not been contemplated in the scope of the AMI project. The components of the approved AMI project plan include CIS replacement, meter data management system ("MDMS") replacement, head-end system replacement, AMI network deployment, AMI meter deployment, AMI integration with the outage management system ("OMS"), enhancements to Volt/Var management, and upgrades to distribution asset management.

From a load settlement perspective, the AMI project plan ensures that AMI interval data are made available for all downstream uses, including load settlement. However, since load settlement systems were not identified as part of the initial scope, the constraint on the intake of interval data by the load settlement system had yet to be identified.¹¹ The Eversource AMI Plan and cost estimate that were filed and approved by the Department in this proceeding, do not include any investments to overhaul the load settlement process to incorporate AMI interval meter data before the end of the AMI meter deployment. Instead, Eversource's AMI Plan indicates that

¹¹ The Supplier Presentation references statements made at the evidentiary hearing in this proceeding where Eversource's witness stated "So the data is available for settlement, and the settlement calculations would consist of more actual data. So we would intend to use that actual data for the same reasons you just noted." (Supplier Presentation at 4 citing Tr. 5, at 1012-1013). This testimony was provided in 2022 before the Company had begun deployment of its AMI investments. Accordingly, while Eversource did **intend** to incorporate **more** actual data into its settlement calculations, this intention of increasing the use of actual data as AMI meters are deployed did not change the AMI Plan timeline to enable TVR in 2029. Further, because Eversource had not yet developed a framework for TVR as of the time that it filed its AMI Plan it should not be surprising that adjustments and/or investments will be necessary to fully accommodate TVR. This is particularly true with respect to complex supplier TVR that will require additional feedback from third-parties. Further, the Company had clearly expressed that even with AMI meters there could be instances where load profiles would continue to be used (D.P.U. 21-80, Exh. TEC-ES-1-2 (stating that "[i]f meters can be switched to AMI, and the network provides increased communication reliability so that data is available for use in settlements, the settlement calculations could consist of more actual data and fewer scaled profiles.")).

"planning" for TVR would not *commence* until Q1 of 2027, with the rollout of the first rates not occurring until Q1 of 2029. Accordingly, Eversource has not initiated any work on a load settlement overhaul to accommodate TVR at this time, nor would it be possible to do so by 2026. To be clear, the request by parties and/or stakeholders that the Department direct the EDCs to make load settlement changes by the end of 2026 represents an unanticipated and costly departure from the approved plans with respect to TVR availability. This is contrary to the Department's agreement with the Companies' indication in D.P.U. 21-80/21-81/21-82 that the stakeholder process, and by extension the results of that process, must not delay implementation of their respective AMI Plans in order to ensure that the AMI investments provide customer benefits in a timely manner. Track 2 Order at 325.

Moreover, all load settlement functions are ultimately governed by the FERC-approved ISO-NE tariff and Eversource must continue to meet its obligations under the tariff. It would not be prudent to hastily change its ISO-NE load reporting processes prior to full TVR planning. Eversource does not recommend pursuing a path of full AMI in load settlement prior to 2029. Rather, Eversource recommends following the original timeline in the approved AMI Plan whereby once all the AMI data and requirements are known, Eversource will fully utilize AMI data for load settlement purposes. This plan is not inconsistent with NSTAR Electric's testimony at the evidentiary hearing in this matter.¹²

It is also important to note that, for major projects with numerous and complex system (inter)dependencies (like AMI), it is not uncommon for new business requirements to come to the surface after the initial scoping and cost estimate. While Eversource endeavors to present the most accurate and complete project scope feasible, project change requests are a normal part of major

¹² See id.

project governance, and the AMI interval-based load settlement enhancements are an example of this. See Track 2 Order at 223. The scope of these interval-based load settlement enhancements was not identified or realized until discussions with stakeholders occurred through the AMI Stakeholder Working Group process.

As discussed above, the need for these enhancements became known through stakeholder discussions regarding how to expedite availability of TVR in response to the Department's directives for the AMI Stakeholder Working Group. In response to this directive to focus on AMI deployment strategies that may expedite the ability for competitive suppliers to offer TVR products, the EDCs proposed to accelerate the activation of rate intake and billing capabilities under standard parameters and bill-ready billing for non-standard designs. This accelerated activation of functionality was determined by the EDCs to be a feasible strategy for expediting the ability of competitive suppliers to offer TVR products. Conversely, because interval-based settlement was not contemplated in the approved AMI Plans, this functionality could not be accelerated. Instead, a proposal for the enhancements necessary to facilitate interval-based settlement would have to be developed and proposed to the Department for approval. While this will not achieve the objective of expediting TVR for suppliers, it is likely that this additional scope of work could be included in Eversource's TVR launch in early 2029 if Department approval is received.

Directing the Companies to implement interval-based settlement on an expedited basis would require adding a load settlement scope of work into the AMI Plans immediately. This would be detrimental to the cost-effective and timely delivery of the benefits scheduled to be delivered before TVR pursuant to the Companies' carefully developed plans. This could also jeopardize NSTAR Electric's ability to comply with the ISO-NE tariff. Based on the foregoing, it is

Eversource's position that it would be imprudent to jeopardize the AMI project timeline with its sequenced customer benefits to accommodate interval load settlement on an expedited timeline. This is particularly true based on the lessons learned by other utilities that successful TVR rollout requires careful design and extensive customer education. It is not clear that Eversource could achieve the necessary customer education on an expedited timeline.

Instead, Eversource is working to produce a cost estimate and timeline for the load settlement upgrades that are necessary to support interval load settlement. NSTAR Electric will submit its cost estimate and timeline to the Department together with a proposal for cost recovery. Eversource's filing would also include an estimate of benefits associated with the necessary upgrades.

Eversource's approved AMI Plan attributed only a \$10.59 million nominal benefit to TVR from the 2029 launch through the end of the 20-year AMI project analysis—2042. The net present value of the estimated TVR benefits over that timeline was calculated to be \$3.84 million.¹³ The benefit projections were based on a TVR adoption assumption of 6.3% of customers across all classes. However, given the participating suppliers' enthusiasm for TVR and the fact that approximately 77% of customers are served under municipal aggregation or individual supply agreements, it is possible that TVR adoption could be significantly higher.¹⁴ Accordingly, the sensitivity table below shows how different TVR adoption scenarios affect the TVR benefits assessment in the 2021 analysis, illustrating that if suppliers are successful in achieving higher

¹³ See also D.P.U. 21-80, Exh. AC 1-8 (explaining that due to the evolution of technology, AMI is the only feasible operating alternative as compared to other technology solutions and has become part of the natural progression of the operating platform. The company further explained that benefits from TVR had become less necessary to justify AMI and therefore proposing an opt-out approach to TVR was not required.).

¹⁴ D.P.U. 21-80, Exh. AC 1-11 (noting that the Company took a conservative approach to its forecast of future benefits including the forecast of future benefits associated with TVR).

TVR adoption rates, the expected benefits could justify a determination by the Department that the substantial investments in interval-based load settlement capabilities are justified.

Table 2. Eversource Energy Illustrative Analysis of TVR Benefits

TVR Benefits (2022-2042)											
	Residential and C&I TVR Participation (%)										
	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Nominal total	\$0.0 M	\$16.8 M	\$33.6 M	\$50.4 M	\$67.3 M	\$84.1 M	\$100.9 M	\$117.7 M	\$134.5 M	\$151.3 M	\$168.2 M
NPV	\$0.0 M	\$6.1 M	\$12.2 M	\$18.3 M	\$24.4 M	\$30.5 M	\$36.6 M	\$42.7 M	\$48.8 M	\$54.9 M	\$61.0 M

For example, Table 2 demonstrates that if TVR participation increases to 50% (versus the 6.3% assumed in Eversource’s original AMI benefits model relied on to support approval of its AMI Plan), the nominal total of estimated benefits would be \$84.1 million, and the NPV of those estimated benefits would be \$30.5 million (preserving all other assumptions in the original model). Where actual TVR adoption eventually falls in the range will be driven by a number of factors, including the thoughtfulness of TVR design and the effectiveness of customer education. However, this analysis shows that there is the potential for a Department determination that the benefits outweigh the costs. Eversource will continue to evaluate potential benefits for inclusion in a filing later this year with its cost estimate.

Eversource also notes that there is no risk that identifying these system enhancements after the AMI Plan was approved and after project commencement has increased costs through lost economies of scale. The load settlement system is an independent downstream consumer of data from the CIS (and MDMS after AMI is deployed). This means that there is virtually no risk of inefficiencies or wasted investment associated with addition of the load settlement investments after the initial project is completed. In fact, waiting until the new CIS and MDMS are stable and producing interval data efficiently for the majority of AMI customers will allow for more confident design, implementation and testing of the downstream load settlement upgrades.

In summary, Eversource is proud of its on-schedule AMI deployment progress to date and the benefits already being delivered to customers and is committed to delivering the projected value to customers outlined in its approved AMI plan.

b. National Grid

As discussed above, each of the EDCs identified multiple benefits of AMI. National Grid specifically identified benefits including the following: (1) outage reporting; (2) remote metering capabilities; (3) interval metering; (4) innovative rate designs; (5) data sharing; and (6) system monitoring and advanced planning.¹⁵ AMI provides numerous remote capabilities that enable more efficient operations including providing improved outage reporting and data to the company's outage management system ("OMS") which will allow dispatch and operations staff to more efficiently and effectively manage outage events. Other remote metering capabilities include the ability to remotely measure usage and ensure more accurate customer billing, identify and process outage data for enhancements to the OMS and the restoration process, conduct meter investigations for meter-related issues, identify events and alarms, and issue connect, disconnect, and reconnection functionality as permitted by the Department's billing and termination regulations.

The interval metering from AMI provides the data necessary for more accurate customer billing and enhanced customer insights into their energy usage. This data also enables advanced demand management programs and other customized customer programs focused on controlling or reducing energy consumption. When deployed, National Grid's AMI meters provide 15- minute interval data that uploads to National Grid's back-end system daily and is "Validation, Estimation,

¹⁵ The benefits of National Grid's AMI Plan were identified in D.P.U. 21-81, Exhibit NG-AMI-1, at 20-22, 30-31; Exhibit NG-AMI-2 at 23-25, 29-37; and Exhibit NG-AMI-5.

and Editing” (“VEE”) quality data within 24-48 hours. VEE is a process that takes raw meter data and puts it through a series of rules and checks to ensure accuracy, fill in missing data with estimations, and flag any issues for additional review.

The granular and timely interval meter data that will be available from AMI meters will enable innovative rate designs to evolve and enable customers to more effectively manage their energy needs. Data sharing is a foundational tool that will allow customers and third parties to use the data to inform behaviors, products, and programs leading to a reduction in energy consumption. National Grid has updated its Green Button Connect (“GBC”) scope of work to include AMI interval data. National Grid is also in the process of setting up API bulk data sharing capabilities through Utility API; this is expected in 2026. This API repository will be able to be leveraged for the central data repository required by M.G.L. c. 164, § 116C(a). Each of the EDCs is enabling an API data platform but in order to enable a central repository, the EDCs will also need a “landing page” that is managed by a third-party (e.g., Department of Energy Resources). This landing page would direct a user to the API platforms for API data sharing in order to create a central data repository. This landing page was not included in the EDCs AMI plans or AMI plan budgets; as a result, this landing page will require additional cost recovery authorization from the Department.

AMI meters will also provide loading and voltage data that will facilitate National Grid’s advanced planning, load forecasting, and management of distributed energy resources.

As discussed above, National Grid’s AMI meters will enable innovative rate design including TVR. National Grid’s deployment timeline for its AMI plan is approximately four and a half years, and was expected to run from 2024 through 2027.¹⁶ While National Grid’s AMI Plan

¹⁶ The timeline was proposed subject to the timing of the Department decision in this proceeding. See D.P.U. 21-81, Exhs. NG-AMI-1, at 19 and NG-AMI-2, at 44.

recognized the potential benefits of TVR, the AMI plan did not include a specific proposal for TVR design or implementation.¹⁷ National Grid's AMI rollout was scheduled for 2024-2027 and while TVR functionality was to be enabled during the AMI deployment phase, actual implementation was dependent on future regulatory proceedings and was not anticipated to be available until after deployment.

National Grid reiterated its inability to make TVR available in the short-term in its Electric Sector Modernization Plan, stating that "[t]he Company's current billing systems have little ability to bill customers at rates that reflect both demand and energy usage or time-of-use. TVR are limited today primarily to large [commercial and industrial] customers. The Company's current billing system is not built to efficiently implement TVR at the scale required for residential customers in coming years to realize the benefits of new-AMI enabled rates."¹⁸ To enable TVR will require definition of the parameters of TVR, time to fully scope the timeline and costs to achieve implementation. This is not inconsistent with National Grid's representations in this docket.

Further, contrary to statements made by others at the July 15, 2025 technical session in these dockets, National Grid did not state that it would have interval data available for ISO-NE settlement by 2024/2025. Rather, National Grid testified that its AMI deployment timeline went through 2027,¹⁹ and that it could use more granular data when reporting hourly load to ISO-NE

¹⁷ D.P.U. 21-81, Exh. NG-AGMI-2, at 23-24.

¹⁸ D.P.U. 24-11, Exh. NG-ESMP-1, at 278.

¹⁹ D.P.U. 21-80/21-81/21-82, Transcript of April 7, 2022 Evidentiary Hearing, p. 796, l. 21 to p. 797, l. 6: "Q. Okay. So help me out. What is the new deployment timeline, just for the meters? A. [KIEFER] Just for the meters? Q. Yes. A. [KIEFER] That would be July of 2024 to June of 2025, would be the first 30 percent. And then July of 2025 to June of 2026 would be 40 percent, so at that point you'd have 70 percent of the meters deployed. And then the final 30 percent would be July of 2026 to June of 2027."

“when we have it and are able to incorporate that into the process,”²⁰ i.e., after the deployment of the AMI meters and the supporting network and back-office infrastructure, and after the Company analyzed its ability to do so.²¹ National Grid’s evidence also made clear that additional investments might be needed, beyond those proposed in its AMI plan, in order to make certain products available.²²

²⁰ D.P.U. 21-80/21-81/21-82, Transcript of April 7, 2022 Evidentiary Hearing, p. 810 l. 4-16: “Q. So 80 percent of the meters installed between midyear 2024 and midyear 2025. The communications in place. The back office stuff is in place to process it. Once the meter’s installed, will you use meter usage when reporting hourly load to ISO New England, or will you continue to use load profiles? A. [KIEFER] We’ve talked a little bit about this as a team. I think we will continue – my understanding is that we will continue – the process will remain unchanged, but we will use the more granular data when we have it and are able to incorporate that into the process.” The question mis-stated the witness’s prior testimony on the meter installation schedule. The witness testified that 30 percent of the meters would be installed by June 2025, and 70 percent of the meters would be installed by June 2026, not that 80 percent of the meters would be installed by midyear 2025. See D.P.U. 21-80/21-81/21-82, Transcript of April 7, 2022 Evidentiary Hearing, p. 796, l. 21 to p. 797, l. 6.

²¹ D.P.U. 21-81, Exhibit AG 5-11, parts e and f (Requests: “(e). Describe any plans the Company has to use smart meter data to settle energy charges based on hourly market prices to Municipal Aggregators and retail electric suppliers on a customer-specific basis. (f). Describe any plans the Company has to use smart meter data to assign capacity costs to Municipal Aggregations and retail electric suppliers based on the peak load contributions of these entities’ customers.” Responses: “e. The process for wholesale energy settlement will remain unchanged. With the implementation of AMI, the Company will maintain its existing role as the wholesale meter reader for municipal aggregators and other market participants, using the same methodology of load profiled asset settlement. f. The Installed Capacity (“ICAP”) for each supplier is calculated by the ISO-NE from information provided by the Wholesale and Retail Market Settlement group at National Grid. The reported ICAP is based on the aggregate of each supplier’s customers’ contributions to the ISO-NE peak load during the preceding year. The individual customers’ contributions (i.e., tags) are estimated annually. The daily supplier requirements are then calculated by tracking customer enrollment changes and shifting load accordingly.”).

See also Exhibit TEC-NG-1-6 (Request: “Please explain the investments that the Company will make to enable settlement of customer load based on actual interval meter data in ISO-NE markets. In the response, please clarify which ISO-NE settlement period will utilize AMI data. For example, will the Company rely on profiled loads for initial settlement and then use AMI interval meter data for final settlement, or will all ISO-NE settlement activities utilize interval meter data from the AMI systems?” Response: “The Company will analyze AMI resettlement capabilities as part of the 18-month back-office design and integration phase of the project. Please see the Company’s responses to Information Requests AC 1-24 and AG 5-11, parts e and f, for additional discussion of AMI-related considerations relative to ISO-NE settlement.”)

²² D.P.U. 21-81, Exhibit NG-AMI-2, at 37 (with regard to FERC Order 2222, “AMI would also not be a solution for the telemetry and more real-time data exchange requirements for certain market products based on currently available technology. Achieving such functionality would likely require installation of additional equipment.”) (emphasis added); Exhibit AC 1-24 (“Request: While the Company mentions a plan for 15-minute interval data using AMI, ISO- New England requires 5-minute interval data for demand response assets to participate in wholesale markets. Please provide more information about why this level of granularity was not included in the plans. Will the Company commit now to reprogramming meters at zero cost or a low, defined cost to adjust the time interval of collection, whenever necessary in the future to accommodate different ISO-New England markets and settlement requirements? Response: Currently, customers who participate in the ISO-New England wholesale market via the demand response resource participation model pay to have a KYZ pulse output from their interval meter. In

National Grid currently provides interval data to ISO-NE for wholesale and commercial and industrial (“C&I”) accounts. National Grid currently has no pathway to ingest residential interval data into its ISO settlement system; to accomplish this would require significant changes to National Grid’s meter data management, settlement and billing systems. In order for National Grid to update its ISO settlement system, it will take three to six months to compile a business analysis with a proposal as this was not part of the original AMI proposal and order.

Additionally, National Grid has separate load profiles for peak and off-peak periods. Each profile reflects average usage patterns for customer types (residential, C&I, etc.). This aligns better than static load profiles. Current limitations within National Grid’s infrastructure require using load profiles until upgrades are made to National Grid’s internal systems to accommodate the new AMI interval data for residential customers.

National Grid will continue using load profiles for settlement for customers who are not on time-varying rates (i.e., who are not billed using interval data). For customers who will be on time-varying rates in the future (i.e., who will be billed using interval data in the future), once the investments described above are made, National Grid will be able to provide their interval data to ISO-NE for settlement.

compliance with the current tariff provisions, customers interested in participating in demand response in the wholesale market can continue to satisfy the ISO-NE requirement using a KYZ pulse output from the AMI vendor’s commercial and industrial meter, which includes a KYZ adapter. Going forward, however, the Company anticipates that wholesale market settlement for demand response may transition away from KYZ outputs to an alternative, such as using a WiFi protocol. The AMI vendor’s residential metering technology, which would be used for the bulk AMI deployment, can accommodate such a change through over-the-air programming. As with the current KYZ outputs, such a transition may require additional costs based on, among other things, the number of participants, as well as the volume and type of data transmitted.” (footnotes omitted; emphasis added)

c. Unitil

Unitil's advanced metering functionality vision, as set forth in its Grid Modernization Plan ("GMP") in D.P.U. 21-82, included AMI, Interval Metering, and a Meter Data Management System (MDMS).²³ While Unitil recognized AMI as a foundational investment that could facilitate TVR, including time of use (TOU) rates, it was not the exclusive or primary benefit. Similar to National Grid and Eversource, the benefits of Unitil's advanced metering functionality plan include, among other things: improved outage reporting and outage and circuit management; remote measurement and metering capabilities, including remote connection and disconnection; implementation of VVO to actively monitor and control load and power factor to reduce peak capacity during peak demand periods; enhanced system monitoring, which reduces O&M costs; enhanced system planning; data sharing; innovative rate designs; enabling customer insight into energy use; energy conservation and lower customer bills; demand side management and demand response programs; reduced peak demand and deferred increases in capacity; and optimization of renewable resources²⁴ With respect to innovative rate designs, including TOU rate structures, Unitil stated it was in the process of reviewing how rate design could be leveraged to enable customers to effectively manage their energy needs.²⁵ Unitil emphasized that it would be necessary to understand and evaluate how customers are responding to TOU rate options in order to make periodic refinements to TOU rate design and identify how the utility's load shape and resulting costs may change over time.²⁶ Unitil is unique in the Commonwealth in that it first installed AMI on its system approximately fifteen years ago. AMI has allowed Unitil to achieve

²³ D.P.U. 21-82, Unitil GMP at 35.

²⁴ D.P.U. 21-82, Unitil GMP at 35-39, 86-89, 92-100; see also D.P.U. 21-82, Track II Order at 53, 270.

²⁵ D.P.U. 21-82, Unitil GMP at 26.

²⁶ Id. at 60.

savings in reduced staffing; provide more timely and accurate bills; eliminate the need for additional truck rolls to read meters; allow for virtual turn-ons and turn-offs (which reduces labor costs); reduce billing complaints and allow for timelier dispute resolution; provide timely outage information, which reduces overall restoration time; and reduce the cost of lost revenue with tamper and theft related tools.²⁷ Though Unitil’s original AMI installation was state of the art when it was installed, at the time Unitil submitted its 2022-2025 GMP, the meter system had been outpaced by new technology that could provide more information in a more timely²⁸ Thus, Unitil proposed to replace its existing “TS2” meters with more advanced “PLX” meters.²⁹

Unitil’s deployment timeline for its AMI replacement system is by year end 2025.³⁰ Though Unitil acknowledged the benefits of TOU and TVR rate structures, it did not specify a specific timeline for implementation of TOU or TVR subsequent to the full deployment of AMI replacement meters. Importantly, supplier TVR was not included or evaluated as a benefit in Unitil’s GMP. With respect to load settlement, Unitil clearly stated, in multiple responses to information requests, that load settlement was outside the scope of its GMP and AMI plan. Specifically, Unitil explained it “did not have any plans . . . to use smart meter data for the wholesale settlement of energy charges with hourly market prices to Municipal Aggregators and retail electric suppliers.”³¹ Unitil further explained that the use of such information for wholesale

²⁷ D.P.U. 21-82, Unitil GMP at 23, 25.

²⁸ Id. at 36.

²⁹ Subsequent to proposing its initial GMP, Unitil proposed to deploy a different type of meter (Revelo) instead of the PLX meters that were approved in D.P.U. 21-82 due to the vendor’s anticipated discontinuation of the PLX technology. D.P.U. 24-54, at 6 (March 28, 2025). The Revelo meter implementation, which is currently underway, will occur on the same timeline as proposed for PLX meter implementation, provide additional functionality to customers, and remain at a comparable cost to its approved AMI implementation plan. Id. at 6-7, 13-15.

³⁰ D.P.U. 21-82, Unitil GMP at 88.

³¹ D.P.U. 21-82, Exh. AG 3-13(e).

settlement would necessitate additional programming, testing, and system integration not contemplated in the GMP:

PLX meters currently collect 15-minute interval data that is capable of being used for wholesale settlement of energy charges. This data is stored in the Meter Database Management System (MDMS) but at this time it is not used for the wholesale settlement process. To enable the use of the MDMS information for wholesale settlement, the MDMS would need to be customized to convert the 15-minute interval data into hourly intervals that could be used for wholesale settlement. This would require programming, testing, and system integration to incorporate the PLX interval data into the wholesale settlement process.³²

Accordingly, consistent with the positions set forth by Eversource and National Grid, enabling these functionalities would require additional investments following a determination by the Department that such investments are justified and prudent.

IV. Central Data Repository and Data Sharing

As set forth in the Companies' June Joint Comments, the EDCs continue to support data sharing requirements that align with the proposal set forth in Appendix C of those comments. The EDCs also support third-party administration of a central data repository; during the July 15, 2025 technical session DOER stated that it was willing to consider acting as the governing body for this central data repository. The Companies support additional discussions with DOER to identify whether this is feasible and, if so, next steps.

In addition, the EDCs continue to request Department guidance regarding: (1) their proposal for an opt-in approach to data access and (2) incremental costs associated with GBC requirements (i.e., the EDCs would incur additional costs if directed to provide bill print data through GBC); and (3) incremental costs associated with the central data repository implementation.

³² D.P.U. 21-82, Exh. DPU 9-6.

V. Accelerated Switching

As detailed in the June Joint EDC Comments, development of an implementation plan for accelerated switching requires guidance from the Department. The EDCs provided a list of items that require Department guidance in the June Joint EDC Comments that remain unanswered and must be addressed. As the Companies have stated in earlier comments, implementation of accelerated switching will involve significant changes to the EDCs' CIS and billing systems, as well as changes to the EDI system that would require engagement with the EDI working group; without guidance and clarity from the Department, the EDCs may incur unnecessary costs that could otherwise be mitigated.

VI. Conclusion

The EDCs appreciate this opportunity to provide additional comments and to respond to the issues raised at the July 15, 2025 technical session. The Companies will continue to implement their respective AMI Plans and are prepared to present additional analyses to the Department regarding the enhancements necessary to facilitate interval load settlement. Because these investments were not included in the previously-approved AMI Plans, the EDCs propose submitting a business case analysis for these additional investments together with a proposed implementation timeline.

Finally, the EDCs reiterate their previous requests for Department guidance on the central data repository and accelerated switching. Providing this guidance will ensure that these issues are resolved in a manner that is efficient and mitigates the risk of unnecessary costs.