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Rhode Island Energy™
a PPL company

February 2, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-53-EL - Rhode Island Energy's Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan
Responses to Data Requests – PUC Set 1

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please see the Company's responses to the Public Utilities Commission First Set of Data Requests in the above referenced docket.

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

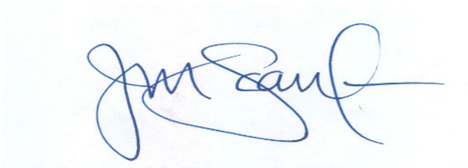
Enclosures

cc: Docket No. 22-53-EL Service List
John Bell, Division
Greg Booth, Division
Christy Hetherington, Esq.
Al Contente, Division

<u>Certificate of Service</u>

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.



Joanne M. Scanlon

February 2, 2023
Date

Docket No. 22-53-EL – RI Energy's Electric ISR Plan FY 2024
Service List as of 1/18/2023

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Matt Sullivan, Green Development LLC	ms@green-ri.com;	

PUC 1-1
Relationship to AMF Proposal in Docket No. 22-49-EL

Request:

On Bates page 77 of the ISR Electric Capital Plan, the plan states:

> "The Company's Advanced Metering Functionality ("AMF") meters and associated systems (filed in a separate Docket) are foundational investments for grid modernization that provide data to update the network model every 45 minutes during the day (as opposed to monthly data in the past)." (emphasis added)

In the testimony filed in the AMF docket (Bates page 16), it also states:

> "The granular information that AMF provides is both foundational to and enhances many of the GMP functionalities. As a result, it makes sense to move forward with AMF first. Simply put, AMF is necessary and valuable independent of the GMP, and grid modernization cannot be fully realized without AMF, making AMF prerequisite for, and foundational to, the GMP." (emphasis added)

a) Given the representations that AMF is foundational to and a prerequisite to Grid Modernization, does the Company's proposal in this proceeding to commence spending $33.9 million in CY 2023 for Grid Modernization investments pre-suppose Commission approval of the Company's proposal to deploy AMF (pending in a Docket No. 22-49-EL)?

b) Please explain how the Company's proposed investments in Grid Mod would be prudent to advance prior to knowing the outcome of the AMF proposal.

Response:

a) No. The Company's proposal to spend $33.9 million in calendar year ("CY") 2023 to make the initial Grid Modernization investments does not presuppose Commission approval to deploy AMF and it is not dependent upon the Commission's approval of the pending AMF Docket to provide value. Rather, the $33.9 million in CY 2023 is the initial commitment to a set of highly integrated solutions to be deployed over multiple years that are collectively referenced as Foundational Investments in the GMP. The Foundational Investments are the investments that the Company believes are reasonably necessary, prudent, and nondiscretionary, with or without AMF, that bring value on their own and are needed now to manage the emerging complexity of the system. The benefits that can be achieved from the Foundational Investments will be further enhanced with

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PUC 1-1, page 2

Relationship to AMF Proposal in Docket No. 22-49-EL

AMF when it becomes available. These Foundational Investments are needed to digitize key distribution assets to bring visibility and greatly enhanced operating capability to manage an increasingly complex system reliably and safely.

b) The Company's proposed Foundational Investments are prudent to advance prior to knowing the outcome of the AMF proposal because the collection of integrated solutions is urgently needed to responsibly manage the electric distribution system now and in the future. The Foundational Investments represent the best path forward for optimal benefits that will enable much more efficient use of the existing and planned distribution system and allow the DER needed in connection with the Climate Mandates to interconnect at a reasonable cost and within a reasonable time frame. Without grid modernization, the distribution system has limited visibility and control. With this limited visibility and control, DER interconnection and operation cannot be optimized. This will result in increasing interconnection costs and increasing interconnection study timelines, more and longer outages, voltage violations. Delaying the Foundational Investments will further magnify the challenges and risks listed in part (a) of the response to PUC 1-12 and may cost customers more over time because the operating complexities will continue to grow. The Company believes the optimum approach is to proceed with the Foundational Investments; when AMF granular meter information becomes available, it will further enhance capabilities of the Foundational Investments because meter information from along the feeder increases visibility and provides the ability to further optimize the management of the system.

Prepared by or under the supervision: Wanda Reder

PUC 1-2

Relationship to AMF Proposal in Docket No. 22-49-EL

Request:

Referring to the Grid Modernization investments listed in Attachment 3 on Bates page 115:

a) Please identify each of the proposed Grid Modernization investments which are dependent upon the deployment of AMF to achieve net benefits.

b) Please identify each of the proposed Grid Modernization investments, if any, which are not dependent upon the deployment of AMF to achieve net benefits and, therefore, the Company believes are prudent to install with or without AMF being deployed.

Response:

a) Benefits from solutions in the Foundational Investments are not assigned to specific investments; rather the grid modernization solutions are highly integrated in a comprehensive plan to achieve optimum benefits that are required under any scenario to mitigate operating criteria violations and enable the State to achieve the Climate Mandates most effectively. Therefore, the net benefits from the Foundational Investments are not dependent upon AMF to achieve them; rather the benefits resulting from the Foundational Investments would be enhanced with AMF.

b) The Company believes that all of the Foundational Investments in the GMP are prudent to install with or without AMF being deployed because the grid modernization solutions are integrated to offer net benefits with or without AMF. The best path forward and the most optimal approach is to integrate AMF with the Foundational Investments because it offers the most benefit for the least cost. The Foundational Investments are planned in a sequenced progression that establishes fundamental grid modernization capability from highly integrated solutions that result in incremental benefits (with or without AMF), as the investments are made. AMF enhances the benefits as discussed in Section 6.7 of the GMP (Bates 155-158) which describes the AMF and GMP linkages and how the functionalities from AMF enhance GMP allowing for better observability, planning, and control of the distribution system and DER.

Prepared by or under the supervision: Wanda Reder

PUC 1-3

Five-Year Forecast of Spending

Request:

Using Attachment 3 (Bates pages 115-117) and the spending information provided in the AMF filing in Docket No. 22-49-EL, please create two tables that show the proposed/forecasted annual and cumulative spending numbers for the five-year period from CY 2023 through CY 2027, in table formats similar to the following:

	Table 1-3(a)	CY 23	CY 24	CY 25	CY 26	CY 27	CUMULATIVE TOTAL	NPV
1	Elec. ISR Grid Mod	33,877	47,983	61,179	64,831	61,542	269,412	
2	Electric ISR Other							
3	Total ISR	147,365	180,405	203,458	196,634	174,029	901,891	
4	AMF Capex/Opex							
5	TOTAL ISR/AMF							
6	Estimated Rev. Req.							

	Table 1-3(b)							
7	Elec. ISR Grid Mod							
8	AMF Capex/Opex							
9	TOTAL Grid Mod/AMF							
10	Estimated Rev. Req.							

Referring to the requested revenue requirement estimates on lines 6 and 10 of the respective tables, please provide a high-level estimate of the incremental revenue requirement needed to finance the spending in each year, including the cumulative total of incremental rate increases by the end of the fifth year. With the understanding that a precise calculation may be complicated and burdensome to produce, the Company should use as many simplifying assumptions as needed to provide a reasonable high-level, order-of-magnitude estimate of the annual rate increases that the Company contemplates it will be seeking over the five years for the applicable initiatives.

Prepared by or under the supervision: Jeffrey D. Oliveira and Stephanie A. Briggs

PUC 1-3
Five-Year Forecast of Spending

Response:

Please see Attachment PUC 1-3 for the requested tables.

The Narragansett Electric Company d/b/a Rhode Island Energy
Estimated Revenue Requirement on Five-Year Forecast of Spend
Total ISR and AMF

	Table 1-3(a)	CY 2023	CY 2024	CY 2025	CY 2026	CY 2027	Cumulative Total
		($000's)					
1	Grid Mod Capital Spend	$ 33,877	$ 47,983	$ 61,179	$ 64,831	$ 61,542	$ 269,412
2	Other ISR Capital Spend	113,488	132,422	142,279	131,803	112,487	632,479
3	Total ISR Capital Spend	147,365	180,405	203,458	196,634	174,029	901,891
4	AMF Capex/Opex Spend	19,286	72,233	76,197	6,244	7,141	181,101
5	Total ISR Capital /AMF Spend	166,651	252,638	279,655	202,878	181,170	1,082,992
6	Estimate Revenue Requirement - ISR Capital/AMF on current year additions	4,391	12,642	22,791	18,004	12,022	69,850
7	Estimate Revenue Requirement - ISR Capital/AMF on prior year additions (CY 23-CY26)	-	8,486	30,502	72,192	104,435	215,614
8	**Total Estimated Revenue Requirement - ISR capital/AMF**	**$ 4,391**	**$ 21,128**	**$ 53,292**	**$ 90,196**	**$ 116,457**	**$ 285,464**
9	**Incremental Revenue Requirement from Prior Year**	**$ -**	**$ 16,737**	**$ 32,164**	**$ 36,903**	**$ 26,262**	

Notes
1 Docket No. 22-53-EL, Section 2, Page 61, Attachment 3
2 Docket No. 22-53-EL, Section 2, Page 61, Attachment 3
3 Line 1 + Line 2
4 Docket No. 22-49-EL
5 Line 3 + Line 4
6 For current year additions - assumes half year convention in first year
7 For prior year additions
8 Line 6 + Line 7
9 Current Year Line 8 less Prior Year Line 8

Assumptions:
a) ISR - CY 2023 & CY 2024 ISR Capital Revenue Requirement presented from revenue requirement filed in Docket 22-53-EL
b) ISR - CY 2025 through CY 2027 ISR Capital Revenue Requirement - used Company forecast of Plant in Service - applied the CY 2024 % of revenue requirement to plant in service
c) ISR - The 3rd year of revenue requirement and forward assumes the same level of revenue requirement as the second year
d) AMF - Revenue requirements from Docket 22-49-EL (converted to Calendar Year periods)
e) ISR & AMF - The estimated revenue requirements are only for new additions related to ISR and AMF from CY 2023 forward
f) ISR & AMF - The first year revenue requirement for each investment year assumes a half year depreciation convention
g) All revenue requirements are based on capital In-Service dates; not capital spend

The Narragansett Electric Company d/b/a Rhode Island Energy
Estimated Revenue Requirement on Five-Year Forecast of Spend
Grid Mod and AMF

	Table 1-3(b)	**CY 2023**	**CY 2024**	**CY 2025**	**CY 2026**	**CY 2027**	**Cumulative Total**
		($000's)					
1	Grid Mod ISR Capital Spend	$ 33,877	$ 47,983	$ 61,179	$ 64,831	$ 61,542	$ 269,412
2	AMF Capex/Opex Spend	19,286	72,233	76,197	6,244	7,141	181,101
3	Total Grid Mod ISR Capital /AMF Spend	53,163	120,216	137,376	71,075	68,683	450,513
4	Estimate Revenue Requirement - Grid Mod Capital/AMF on current year additions	1,426	7,387	11,289	10,622	5,868	36,592
5	Estimate Revenue Requirement - Grid Mod Capital/AMF on prior year additions (CY 23-CY26)	-	2,612	15,931	34,618	52,098	105,259
6	**Total Estimated Revenue Requirement - Grid Mod capital/AMF**	**$ 1,426**	**$ 9,999**	**$ 27,220**	**$ 45,240**	**$ 57,965**	**$ 141,851**
7	**Incremental Revenue Requirement from Prior Year**	**$ -**	**$ 8,574**	**$ 17,221**	**$ 18,020**	**$ 12,725**	

Notes
1 Docket No. 22-53-EL, Section 2, Page 59, Attachment 3
2 Docket No. 22-49-EL
3 Line 1 + Line 2
4 For current year additions - assumes half year convention in first year
5 For prior year additions
6 Line 4 + Line 5
7 Current Year Line 6 less Prior Year Line 6

Assumptions:
a) Grid Mod - CY 2023 & CY 2024 Grid Mod Capital Revenue Requirement calculated from amounts filed in Docket 22-53-EL
Grid Mod - CY 2025 through CY 2027 Grid Mod Capital Revenue Requirement - used Company forecast of Plant in Service - applied the CY 2024
b) % of revenue requirement to plant in service
c) Grid Mod - The 3rd year of revenue requirement and forward assumes the same level of revenue requirement as the second year
d) AMF - Revenue requirements from Docket 22-49-EL (converted to Calendar Year periods)
e) Grid Mod & AMF - The estimated revenue requirements are only for new additions related to Grid Mod and AMF from CY 2023 forward
f) Grid Mod & AMF - The first year revenue requirement for each investment year assumes a half year depreciation convention
g) All revenue requirements are based on capital In-Service dates; not capital spend

PUC 1-4

Five-Year Forecast of Spending

Request:

The first column of data in Attachment 3 contains a heading "FYTD Actuals 9/30/22." The second column also contains a heading "FY23 Q2 Forecast." Please provide an updated Attachment 3 with the most up-to-date information available for these columns.

Response:

Please see Attachment 3 in Docket No. 22-53-EL - Electric FY2024 ISR Plan filed on January 27, 2023, for the most up-to-date information for fiscal year to date actuals and FY23 forecast. Please note, the December filing showed the FY23 Q2 forecast. The supplemental filing shows a preliminary FY23 Q3 forecast. The finalized Q3 forecast will be provided through the third quarter report filed in Docket No. 5209 due February 15, 2023.

PUC 1-5
Supply Chain Issues

Request:

Given the deployment schedule for Grid Modernization that is reflected in the plan, to what extent does the Company believe that delays from supply chain issues being experienced by utilities across the country could negatively impact the ability of the Company to reach the proposed spending and installation schedules in the plan for CY 2023 and/or CY 2024? Please explain.

Response:

Based on the actions taken to date and the strategies detailed below, the Company believes that that the supply chain delays will not materially impact the ability to deliver on the spending and installation schedule for FY 2024 (April 1, 2023 through March 31, 2024). Lead time delays that are being experienced by utilities across the country have been anticipated, and the Company is planning accordingly to execute the FY 2024 spending and installation schedule. Factors impacting the supply chain delays are raw material shortages, low inventories, and labor shortages. Meanwhile, as utilities plan to modernize their grids, the competition for goods and services are likely to increase: those utilities that collaborate with vendors and commit to multi-year production schedules will receive preferential terms over those not having long term arrangements. The practical reality is that which took weeks to deliver before the pandemic, now takes many months to deliver and the lead times are getting longer. For example, before the supply chain constraints the typical lead time for reclosers was 12-18 weeks. In November 2022 the Company provided a response to Division 2-10 that indicated the lead time for reclosers was 8 months (32 weeks). Now, in January 2023, recloser lead time is 36+ weeks.

A continuous and reliable supply of grid modernization equipment, software and services will be needed to execute the Company's GMP. To accomplish this, Rhode Island Energy recognizes the importance of urgently acting to ensure the success of the project and has incorporated direct vendor feedback into the planning to meet the project schedule. The Company also is preparing to establish long-term, multi-year contractual terms for the grid modernization solutions by working with PPL Supply to meet the ongoing deployment schedule and receive the most favorable terms with volume commitments. These terms will provide vendors with certainty to plan and execute on their delivery commitments. Given the current supply chain conditions, the installation schedule cannot be achieved without having multi-year contractual terms and corresponding long-term delivery commitments in place.

Prepared by or under the supervision: Wanda Reder

PUC 1-6
Large Projects and Programs Testimony

Request:

(Revised as a result of January 20, 2023 open meeting decision):

In the pre-filed testimony at Bates pages 34 through 37, there are questions and answers under the heading of "Large Projects and Programs." In each instance, the budget figures are stated for "FY 2024" which covered the two periods CY 2023 (April 1, 2023 through December 31, 2023) and all of CY 2024. Please provide the break-out of each of those projects/programs, showing the spending in FY 2024 (April 1, 2023 through March 31, 2024) and FY 2025 (if there is a projection) and indicate the line item(s) in Attachment 3 (as revised) in which each project/program is included. The response should match Attachment 3 (as revised).

Response:

Please see the table below for clarification on the budget figures stated in the joint testimony and the associated line items in Attachment 3.

	FY 2024 ($000)	**FY 2025 ($000)**	**Line Items from Attachment 3**
Asset Condition Projects	8,408	19,429	Centredale Substation Phillipsdale Substation Tiverton Substation BSVS 4kV Substation Ret. Other Area Study Projects – BSVS Other Area Study Projects - CRIW - D-Line Other Area Study Projects - CRIW Equip Repl Other Area Study Projects – Newport Other Area Study Projects – NWRI Other Area Study Projects - Providence
System Capacity & Performance Projects	7,597	9,818	Chase Hill Common Items Nasonville Substation Staples Substation Reliability Imprvmnts Tiverton Substation

Prepared by or under the supervision: Nicole Begnal

PUC 1-6, page 2

Large Projects and Programs Testimony

	FY 2024 ($000)	FY 2025 ($000)	Line Items from Attachment 3
			Weaver Hill Rd Substation Other Area Study Projects - CRIW Other Area Study Projects - East Bay Other Area Study Projects - Newport Other Area Study Projects - NWRI Other Area Study Projects - SCW
Mainline Recloser Program	9,504	-	Mainline Recloser Enhancements
Customers Experiencing Multiple Interruptions "CEMI" Program	1,230	1,640	CEMI-4
Underground Residential Development "URD" Program and Underground "UG" Cable Replacement Program	11,775	11,875	RI.URD RI.UG Cable Replacement

Prepared by or under the supervision: Nicole Begnal

PUC 1-7
Dyer Street/South Street Substation Projects

Request:

On Bates page 98, there is an indication that the project labeled as "Dyer Street Replace Substation" will be complete in March 2023. It states: "The Company forecasts that the capital work on this project will be completed and assets will be in service by March 2023. The removal of the AC building will be completed during March 2023."

(a) (Revised as a result of January 20, 2023 open meeting decision): Does the revenue requirement for FY 2024 (April 1, 2023 through March 31, 2024) include the "Dyer Street Replace Substation" project? If yes, please provide the total capital cost which is being included in the ISR rate base.

(b) Please provide a comprehensive schedule showing a separate breakdown of

   (i) all the costs that were incurred in connection with preparing, designing, and reconstructing the substation at the Dyer Street location before the project plan was changed to relocate the new substation at the South Street substation outdoor yard instead of the Dyer Street location,

   (ii) all the costs that were incurred in connection with decommissioning the Dyer Street substation location after the project plan was changed to relocate the new substation at the South Street substation outdoor yard instead of the Dyer Street location,

   (iii) all the costs associated with designing, constructing, and placing into service the new external substation at the South Street substation outdoor yard, and

   (iv) any subsets of overlapping costs incurred before the project plan was changed to relocate the new substation at the South Street substation outdoor yard instead of the Dyer Street location which related to work that would have needed to be done for the new substation at the South Street substation outdoor yard even if the Company had never considered using the Dyer Street location for the new replacement substation.

Response:

(a) Yes, the FY 2024 revenue requirement includes $1.3 million of targeted plant additions for the "Dyer Street Replace Substation" project.

PUC 1-7, page 2

Dyer Street/South Street Substation Projects

(b)

(i) Capital spending of approximately $1.980 million was incurred in connection with preparing, designing, and reconstructing the substation at the Dyer Street location before the project plan was changed to relocate the new substation to the South Street outdoor yard. Please see column (C) in the table below for a breakdown of the $1.980 million in costs incurred before the location was changed.

(ii) No costs have been incurred in connection with the decommissioning of the Dyer Street substation location. This work is scheduled to begin after the distribution line portion of the work is complete in the spring.

(iii) The total project forecast associated with designing, constructing, and placing into service the new external substation at the South Street substation outdoor yard includes $26.011 million. This total includes both the distribution substation and line projects.

After review, the Company has determined that $0.855 million of the $1.980 million in capital spending incurred through February 2020 were associated with the DC building at the Dyer St location and did not relate to the project at the South Street location. This spending will not be placed into service. Please see column (A) in the chart below for a breakdown of costs associated with the original Dyer St location.

	A	B	C
	Dyer St Location Alternative	**South St Location Alternative**	**Total**
Labor & Benefits	$ 133,333	$ 164,693	$ 298,027
Environmental Consultant	$ 142,329		$ 142,329
Structural Engineer	$ 230,846		$ 230,846
Contractors - Other	$ 122,204	$ 71,806	$ 194,010
Materials - Transformer Payment	$ -	$ 418,649	$ 418,649
Other	$ 226,512	$ 236,050	$ 462,562
Distribution Substation Total	$ 855,224	$ 891,199	$ 1,746,423
			$ -
Distribution Line Costs	$ -	$ 234,032	$ 234,032
Total	$ 855,224	$ 1,125,231	$ 1,980,455

Prepared by or under the supervision: Daniel Glenning

PUC 1-7, page 3
Dyer Street/South Street Substation Projects

(iv) The Company understands overlapping costs to be defined as costs that may have been duplicated due to the relocation of the substation from the Dyer Street location to the South Street location. There are no subsets of overlapping costs incurred before the project was relocated.

Prepared by or under the supervision: Daniel Glenning

PUC 1-8
Reclosers

Request:

Please explain the technical differences and purposes of the "Mainline Recloser Enhancements" referenced in the "System Capacity & Performance" category (estimated to cost $9.5 million in CY 2023) and the "Advanced Reclosers" referenced in the "Grid Modernization" category (estimated to cost $17.4 million in CY 2023).

Response:

The Mainline Recloser Enhancements and the Grid Modernization - Advanced Reclosers investments are described in detail in the response to Division 1-23.

The Mainline Recloser Enhancements and the Grid Modernization - Advanced Reclosers investments will install the exact same devices. The purpose is what differentiates these two spending categories. The Mainline Recloser Enhancements targets circuits with less than 2 mainline reclosers with 3 or more miles of overhead line exposure to a high number of customers. The Company has determined that the lack of reclosers is a contributing factor to the rising System Average Interruption Frequency Index ("SAIFI") values. All reclosers will use the latest control technology aligned with the Grid Modernization Plan ("GMP") and location selection will be aligned with ultimate GMP implementation. In summary, this program targets the highest value reliability opportunities and represents an accelerated portion of the ultimate GMP framework regarding reclosers.

The Grid Modernization – Advanced Reclosers effort is focused on establishment of a Fault Location Isolation and Service Restoration ("FLISR") system. FLISR functionality when used in combination with an Advanced Distribution Management System ("ADMS"), enables engineering and operations personnel to automatically isolate faults and restore service for significant reliability benefits. Further details are provided in Sections 1.8, 1.9, 5.8, and 6.3 of the GMP. This effort incorporates and expands upon the Mainline Recloser Enhancement effort.

Prepared by or under the supervision: Ryan Constable

PUC 1-9
Reclosers

Request:

Why are the Mainline Recloser Enhancements categorized as "System Capacity & Performance" while the Advanced Reclosers are categorized as "Grid Modernization"?

Response:

The Mainline Recloser Enhancement effort is design to target immediate reliability issues associated with circuits with mainline exposure and would be progressed regardless of grid modernization efforts. While the Grid Modernization – Advanced Reclosers effort builds upon and incorporates the Mainline Recloser Enhancement effort, this effort focuses on system-wide deployment to enable Fault Location Isolation and Service Restoration ("FLISR") functionality. Rhode Island Energy created the Grid Modernization category to clearly delineate these investments from traditional investments.

PUC 1-10
Reclosers

Request:

The Company's response to Division 2-10 (from the pre-filed set of data responses) contains the following statement regarding the Company's execution adjustments relating to reclosers that take into account supply chain concerns: "[T]he Company, working with PPL procurement, has locked down approximately 80% of the production slots for the CY 2023 plan and expects to lock down the balance in early January."

(a) Which reclosers does this response address "Advanced Reclosers" or "Mainline Recloser Enhancements?"

(b) Please provide a further explanation regarding what it means to have "locked down" production slots. Does 80% of production slots equate to 80% of the reclosers needed to execute the proposed CY 2023 budget? Is this a binding contractual commitment?

Response:

(a) The response to Division 2-10 specifically addressed the Mainline Recloser Enhancements. However, the Mainline Recloser Enhancements and the Grid Modernization - Advanced Reclosers investments will install the exact same devices.

(b) To clarify, when the Company stated that it had "locked down approximately 80% of the production slots for the CY 2023 plan and expects to lock down the balance in early January", it meant that the Company had locked down production slots for 80% of the reclosers needed to execute the proposed Mainline Recloser Program in the CY 2023 plan.

These orders are contractually binding. Although the contract is binding, if the recloser replacements within the grid modernization scope is less than the total orders, the reclosers can be allocated to PPL Corporation's other utilities in Pennsylvania or Kentucky following the appropriate company-to-company accounting journal entry.

PUC 1-11
Reclosers

Request:

Does the Company have plans that determine the location and sequence of Advanced Reclosure and Mainline Recloser Enhancement installations?

(a) If so, please describe. If not, why not?

(b) What criteria is used by the Company to determine where to install the reclosers in CY 2023 and CY 2024?

(c) (Revised as a result of January 20, 2023 open meeting decision): How many Advanced Reclosers and Mainline Recloser Enhancements are being planned for each of FY 2024 (April 1, 2023 through March 31, 2024) and FY 2025 (if there is a projection) and where would each of these reclosers by installed ?

Response:

(a) Yes, the Company has plans to determine the location and sequence of the Mainline Recloser Enhancement and Advanced Recloser installations. The Mainline Recloser Enhancement program's plan for determining locations was to review circuits with limited sectionalization See the Company's response to Division 1-23, specifically Attachment DIV 1-23 for the prioritized list. The Company's plan for determining the location for the Grid Modernization – Advanced Reclosers has three components: 1) incorporate the advanced reclosers into other planned work; 2) build off the reliability prioritization of the Mainline Recloser Enhancement effort; and 3) focus on high DER penetration areas. Rhode Island Energy is currently actively selecting recloser locations.

(b) Recloser circuits are selected as described in (a) above. Specific street and pole locations are determined considering customer count, line length, and the reliability history of each line segment. Recloser placements are also made to minimize outages to critical customers such as hospitals, schools, and other public service facilities. Selecting the specific recloser location is a common engineering practice that is typically conducted after project origination and during design.

(c) Approximately 100 to 120 reclosers are planned to be installed during FY 2024 (April 1, 2023 through March 31, 2024) for the Mainline Recloser Enhancement effort.

Prepared by or under the supervision: Ryan Constable

PUC 1-11, page 2
Reclosers

Approximately 280 to 300 reclosers are planned to be installed during FY 2024 (April 1, 2023 through March 31, 2024) and 300 to 320 reclosers for FY 2025 for the Grid Modernization – Advanced Reclosers effort.

Attachment PUC 1-11 shows the current and pending recloser sites for the Mainline Recloser Enhancement project. Roughly half of the recloser sites have been selected. The current site number represents a Geographic Information System ("GIS") Id that corresponds to a feeder section.

The Grid Modernization – Advanced Recloser specific sites are being actively selected and are not available at this time.

Prepared by or under the supervision: Ryan Constable

Circuits with less than 2 main line reclosers, more than 500 CS, and more than 3 miles of OH wire.

Circuits	Mainline Recloser Count	Average Customers Served	Tot 5yr Events	Tot 5yr CI	Tot 5yr CMI	Avg Events	Avg CI	Avg CMI	Avg Yr CKAIFI	Avg Yr CKAIDI	Current Site
53-126W41	1	2346	14	28,100	1,136,588	2.8	5,620	227,318	2.40	96.90	Pending
56-155F4	1	1793	15	16,656	746,579	3.0	3,331	149,316	1.86	83.28	Pending
56-85T1	0	2760	12	20,179	1,514,028	2.4	4,036	302,806	1.46	109.71	77035037
53-112W41	1	1899	9	13,855	463,521	1.8	2,771	92,704	1.46	48.82	276107341
53-111J3	0	1087	8	7,154	497,546	1.6	1,431	99,509	1.32	91.54	Pending
53-107W61	1	2458	13	14,589	686,026	2.6	2,918	137,205	1.19	55.82	Pending
53-1201W4	0	915	5	5,417	353,882	1.0	1,083	70,776	1.18	77.35	275497786
56-16F2	1	1828	9	10,084	239,540	1.8	2,017	47,908	1.10	26.21	Pending
56-155F2	1	2009	8	10,968	804,313	1.6	2,194	160,863	1.09	80.07	Pending
53-26W3	1	2341	8	11,776	393,313	1.6	2,355	78,663	1.01	33.60	201196105
53-1201W7	0	806	7	4,020	262,620	1.4	804	52,524	1.00	65.17	Pending
53-102W44	1	2565	10	12,200	551,940	2.0	2,440	110,388	0.95	43.04	276117186
53-15F1	0	1185	5	5,434	338,072	1.0	1,087	67,614	0.92	57.06	Pending
53-107W80	1	2012	5	8,746	411,163	1.0	1,749	82,233	0.87	40.87	Pending
53-48F3	1	3079	5	13,305	1,043,379	1.0	2,661	208,676	0.86	67.77	275668964
53-18F13	1	2207	7	9,489	256,906	1.4	1,898	51,381	0.86	23.28	Pending
53-127W41	0	654	6	2,721	151,517	1.2	544	30,303	0.83	46.34	188190591-1
53-69F3	1	4786	7	19,363	1,143,964	1.4	3,873	228,793	0.81	47.80	275479213
53-112W43	1	986	4	3,906	239,227	0.8	781	47,845	0.79	48.52	Pending
56-63F5	1	2496	10	9,620	376,672	2.0	1,924	75,334	0.77	30.18	275811049
53-13F3	1	714	2	2,740	48,911	0.4	548	9,782	0.77	13.70	Pending
53-107W81	1	2431	13	9,233	1,138,213	2.6	1,847	227,643	0.76	93.64	Pending
56-36W42	1	1876	5	7,088	364,168	1.0	1,418	72,834	0.76	38.82	598117506
53-200W5	1	2019	5	7,611	230,135	1.0	1,522	46,027	0.75	22.80	Pending
56-87F3	1	1276	5	4,465	222,685	1.0	893	44,537	0.70	34.90	638681093
53-23F3	0	1500	5	4,833	319,537	1.0	967	63,907	0.64	42.60	275610667-1
56-63F3	1	2003	5	6,057	547,792	1.0	1,211	109,558	0.60	54.70	204512575
53-5F2	1	2555	7	7,515	1,034,181	1.4	1,503	206,836	0.59	80.95	Pending
53-38F5	0	1710	4	4,927	171,990	0.8	985	34,398	0.58	20.12	198632413
56-3F1	0	1899	3	5,397	442,797	0.6	1,079	88,559	0.57	46.63	275740515
53-21F4	1	2054	5	5,665	423,820	1.0	1,133	84,764	0.55	41.27	Pending
53-38F3	1	1355	4	3,724	172,393	0.8	745	34,479	0.55	25.45	275547141
53-48F6	1	1996	5	5,422	245,562	1.0	1,084	49,112	0.54	24.61	Pending
53-78F4	0	819	3	2,183	262,691	0.6	437	52,538	0.53	64.15	Pending
53-27F5	1	3070	4	7,840	480,951	0.8	1,568	96,190	0.51	31.33	Pending
53-76F7	1	2657	5	6,749	346,631	1.0	1,350	69,326	0.51	26.09	275419440
56-203W3	1	1438	6	3,613	137,107	1.2	723	27,421	0.50	19.07	Pending
53-112W42	1	2900	4	7,210	213,771	0.8	1,442	42,754	0.50	14.74	Pending
53-127W42	0	1038	3	2,533	175,564	0.6	507	35,113	0.49	33.83	275734861
56-42F1	1	2894	7	7,040	370,245	1.4	1,408	74,049	0.49	25.59	196686118-1
56-155F6	1	1727	6	4,132	240,392	1.2	826	48,078	0.48	27.84	276008083-1
53-102W52	0	1428	6	3,292	104,224	1.2	658	20,845	0.46	14.60	Pending
56-52F1	1	1642	4	3,754	153,814	0.8	751	30,763	0.46	18.73	275382674
53-102W42	1	3144	7	7,182	152,283	1.4	1,436	30,457	0.46	9.69	Pending
53-7F2	1	2046	7	4,660	123,923	1.4	932	24,785	0.46	12.11	275436419
53-48F5	1	3061	5	6,866	248,663	1.0	1,373	49,733	0.45	16.25	275682329
53-13F9	1	3090	8	6,886	870,929	1.6	1,377	174,186	0.45	56.37	Pending
53-18F10	1	2497	3	5,549	117,322	0.6	1,110	23,464	0.44	9.40	Pending
53-18F8	0	1762	3	3,899	169,715	0.6	780	33,943	0.44	19.26	275548505
53-20F1	0	761	3	1,651	49,886	0.6	330	9,977	0.43	13.11	Pending
53-50F2	0	2130	3	4,511	272,864	0.6	902	54,573	0.42	25.62	275527030
53-107W83	0	1418	3	2,993	132,534	0.6	599	26,507	0.42	18.69	Pending
53-5F3	1	2493	3	5,096	271,489	0.6	1,019	54,298	0.41	21.78	275645743
56-61F2	0	1452	2	2,918	142,744	0.4	584	28,549	0.40	19.66	Pending
56-14F2	1	1609	2	3,224	54,640	0.4	645	10,928	0.40	6.79	188192583
53-20F2	1	2095	3	4,120	183,344	0.6	824	36,669	0.39	17.50	Pending
56-64F1	0	1342	3	2,601	263,557	0.6	520	52,711	0.39	39.28	379926575
53-13F5	0	3919	2	7,428	36,627	0.4	1,486	7,325	0.38	1.87	50438726
56-203W5	1	2343	3	4,372	46,549	0.6	874	9,310	0.37	3.97	Pending

Circuits with less than 2 main line reclosers, more than 500 CS, and more than 3 miles of OH wire.											
Circuits	Mainline Recloser Count	Average Customers Served	Tot 5yr Events	Tot 5yr CI	Tot 5yr CMI	Avg Events	Avg CI	Avg CMI	Avg Yr CKAIFI	Avg Yr CKAIDI	Current Site
56-36W41	1	2088	2	3,886	310,346	0.4	777	62,069	0.37	29.73	Pending
56-22F6	1	1937	2	3,030	111,550	0.4	606	22,310	0.31	11.52	Pending
56-61F3	0	987	3	1,501	74,373	0.6	300	14,875	0.30	15.07	275788878
56-63F4	1	2111	2	3,188	227,552	0.4	638	45,510	0.30	21.56	188190591
53-13F10	1	2444	3	3,677	267,180	0.6	735	53,436	0.30	21.86	275809305
53-126W54	1	738	4	1,088	20,392	0.8	218	4,078	0.29	5.53	276001298
56-72F6	0	2411	4	3,422	368,336	0.8	684	73,667	0.28	30.55	275597980
53-27F1	1	1712	3	2,375	67,438	0.6	475	13,488	0.28	7.88	Pending
53-18F7	1	3095	2	4,172	311,904	0.4	834	62,381	0.27	20.16	275431003
53-13F4	1	3837	3	5,171	519,775	0.6	1,034	103,955	0.27	27.09	Pending
56-57J2	0	624	3	829	150,392	0.6	166	30,078	0.27	48.20	Pending
56-36W43	0	1748	3	2,259	88,075	0.6	452	17,615	0.26	10.08	203156715
56-72F4	1	2636	3	3,219	102,324	0.6	644	20,465	0.24	7.76	275452721
56-22F3	0	1153	3	1,394	93,050	0.6	279	18,610	0.24	16.14	275689962-1
53-76F4	1	4997	2	5,950	114,175	0.4	1,190	22,835	0.24	4.57	275492972
53-76F1	1	2094	1	2,295	134,517	0.2	459	26,903	0.22	12.85	200665361
53-51F1	1	2100	2	2,196	127,527	0.4	439	25,505	0.21	12.15	275643182
56-65J12	0	740	1	746	45,350	0.2	149	9,070	0.20	12.26	275912451-1
53-107W66	1	3326	13	3,325	271,540	2.6	665	54,308	0.20	16.33	207823973
56-87F6	0	736	1	732	131,565	0.2	146	26,313	0.20	35.75	Pending
56-72F2	1	2646	1	2,626	175,700	0.2	525	35,140	0.20	13.28	276108858
56-32J14	0	565	1	560	9,548	0.2	112	1,910	0.20	3.38	Pending
53-23F1	1	1518	1	1,503	63,126	0.2	301	12,625	0.20	8.32	275611899
56-14F4	0	879	1	870	83,955	0.2	174	16,791	0.20	19.10	Pending
56-83F4	1	1918	2	1,864	186,034	0.4	373	37,207	0.19	19.40	Pending
53-38F4	1	2571	3	2,482	116,758	0.6	496	23,352	0.19	9.08	275557331
53-1201W3	1	1790	1	1,711	75,284	0.2	342	15,057	0.19	8.41	Pending
53-1201W6	1	3328	7	3,132	216,812	1.4	626	43,362	0.19	13.03	Pending
53-38F6	1	2809	3	2,487	230,131	0.6	497	46,026	0.18	16.39	Pending
56-150F2	0	1735	4	1,322	68,625	0.8	264	13,725	0.15	7.91	642710634
56-203W1	1	1430	5	996	114,427	1.0	199	22,885	0.14	16.00	Pending
56-37W5	0	1983	9	1,262	78,933	1.8	252	15,787	0.13	7.96	Pending
53-1201W1	1	1707	3	1,005	76,450	0.6	201	15,290	0.12	8.96	Pending
56-3F2	1	1901	2	1,085	24,862	0.4	217	4,972	0.11	2.62	275566936-1
56-52F3	1	2698	2	1,512	62,288	0.4	302	12,458	0.11	4.62	Pending
53-1201W5	1	2842	5	1,491	93,639	1.0	298	18,728	0.10	6.59	Pending
56-150F8	1	2533	1	1,210	186,098	0.2	242	37,220	0.10	14.69	275695329
53-48F2	1	572	2	271	30,568	0.4	54	6,114	0.09	10.69	202182416
56-37W6	0	1628	6	755	87,920	1.2	151	17,584	0.09	10.80	Pending
53-102W54	1	2325	2	1,017	89,956	0.4	203	17,991	0.09	7.74	276115366-1
56-87F5	0	1436	1	616	241,793	0.2	123	48,359	0.09	33.68	Pending
56-150F6	1	3525	6	1,450	174,677	1.2	290	34,935	0.08	9.91	Pending
53-108W63	0	2829	2	1,021	16,024	0.4	204	3,205	0.07	1.13	Pending
53-1201W2	1	3145	2	747	97,110	0.4	149	19,422	0.05	6.18	Pending
56-16F4	1	1663	1	373	746	0.2	75	149	0.04	0.09	275552651
53-18F9	1	3626	1	602	9,030	0.2	120	1,806	0.03	0.50	Pending
56-87F1	1	1127	1	57	456	0.2	11	91	0.01	0.08	Pending
53-76F2	0	3984	1	89	2,889	0.2	18	578	0.00	0.15	Pending
56-150F4	1	1951	2	31	3,067	0.4	6	613	0.00	0.31	568531176
56-72F5	1	3341	1	6	780	0.2	1	156	0.00	0.05	275621182

PUC 1-12
Reclosers

Request:

Referring to Attachment 3 (Bates page 115), "Advanced Reclosers" reflects the highest five-year budget of all categories of Grid Modernization (more than $100 million over five years).

(a) Are there other deployment alternatives or project timeline schedules that the Company could implement to significantly reduce the rate impacts of this five-year budget plan?

(b) What is the effect or consequence to the Company if the Grid Modernization program approved by the Commission reflects a material reduction in the "Advanced Reclosers" budget for CY 2023 and/or CY 2024?

Response:

(a) Although the Company could deploy the Advanced Reclosers investments over a longer period, the Company does not recommend this approach. The Company believes that the proposed deployment timeline is urgently needed to responsibly manage the electric distribution system based upon the following trends and operating conditions:

- Deteriorating reliability trends;
- Urgent need to gain visibility, situational awareness, and control of the electric distribution system;
- Increasing cost to consumers without grid modernization;
- Lengthening distributed generation interconnection queue;
- Increased safety and operational risk because of the presence of hidden load during switching;
- Operational complexities such as voltage variability, protection vulnerabilities, and lack of situational awareness as evidenced during the August 2022 Nasonville event;
- High DER adoption rates that are reinforced with the Climate Mandates and various incentives;
- Mounting opportunity costs that will never be realized because DER interconnected today are not integrated in a way that they become mission-critical assets for safe and reliable grid operations; and
- A compromised supply chain, resulting in imminent delays for material availability.

Prepared by or under the supervision of: Wanda Reder

Reclosers

The Foundational Investments included in the ISR investment plan and described in the GMP are the investments that the Company believes are reasonably necessary, prudent, and nondiscretionary. Investment delay will further magnify the challenges and risks listed above and may end up costing customers more money over time because the operating complexities will continue to grow as DER penetration increases.

(b) If the Commission were to order a material reduction in the "Advanced Reclosers" budget for fiscal year 2024, the Company would be unable to achieve the grid modernization objectives as set forth in the GMP. The Company proposed the level and pace of investment based on results of the Distribution Study outlined in Section 5 of the GMP. The proposed investment plan is reasonable and prudent from both a cost and operations perspective to have the necessary functionality to operate the electric distribution system safely and reliably. The consequence of investment delay will negatively impact all the items listed in part (a) above, most notably system reliability. The reclosers are also needed for visibility and management of an increasingly complex system, to reduce the need for seasonal distributed generation curtailment (anticipated in a few more years) and for the State to achieve the Climate Mandates.

Prepared by or under the supervision of: Wanda Reder

PUC 1-13
Transformers

Request:

Has the Company experienced any difficulties in replenishing its inventory of transformers due to supply chain issues or other constraints on the availability of transformers? What is the current status of the Company's inventory? Please explain.

Response:

The Company is experiencing difficulties replenishing inventory and is seeing longer lead times for pad-mount distribution transformers and larger three-phase transformers, which currently are below normal inventory levels. The longer delivery timeframes are being taken into consideration when planning the execution of the proposed FY 2024 Plan. The Company has taken proactive steps, such as securing additional suppliers to mitigate future risk, and the Company anticipates the risk will be mitigated by June 2023 if purchase order dates are met.

Prepared by or under the supervision: Nicole Begnal

PUC 1-14
Fiber

Request:

Regarding the proposed fiber investments,

(a) Please provide a comprehensive explanation regarding the proposed fiber investments that distinguishes between (i) fiber that is installed to upgrade communications to and from substations from (ii) the scope of fiber installations that would be needed to provide back-hauling communications from the AMF meters at customer premises, including geographical scope and cost.

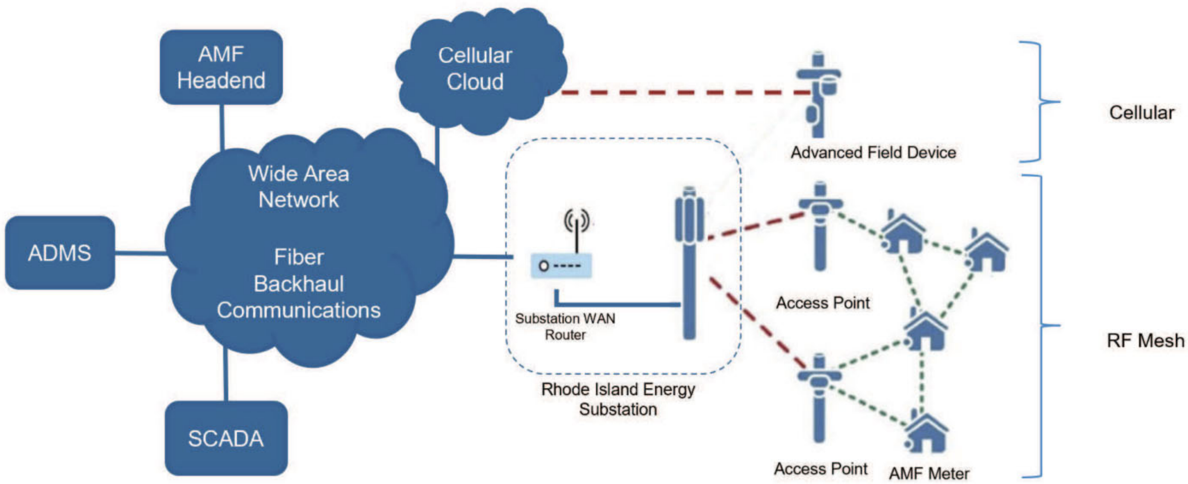
(b) Is it feasible for the fiber deployment to be limited to substation communications? If so, would there be a material reduction in the five-year budget? What would the effect be on the Company's plans and operational expectations?

Response:

(a) The fiber investment that is being proposed as part of the Foundational Investments is to and from substations to the Headend as described in Section 6.5 of the GMP primarily for the purpose of providing real-time operational needs. The fiber infrastructure could be used to backhaul AMF data where applicable and feasible at substation take-off points in addition to being available for SCADA and system protection. The fiber is not being proposed to the customer premise. Communications for AMF to and from customers' premises will be a private RF mesh communication system that is included in the AMF proposal. A diagram illustrating the various communication components was included in the GMP, Figure 6.22 and provided below. Please also see the Company's responses to PUC 1-27 and PUC 1-28 for additional information.

Fiber

Figure 6.22: Communication System with Fiber Backhaul



(b) Yes. Limiting the fiber deployment to substation communications is certainly feasible and it is what the Company has proposed in the Foundational Investments of the GMP and in the ISR investments. There is no funding for fiber deployment in the five-year plan beyond substation communications and as such, there would be no effect on the Company's plans and operational expectations.

PUC 1-15
Fiber

Request:

Please provide a comparison of the cost of cellular-based AMF back-hauling to the cost of a full fiber deployment to serve AMF meters.

Response:

Rhode Island Energy's AMF BCA assumes a privately owned RF mesh network is built to communicate with AMF meters. The backhaul of the meter data to and from the Headend system is assumed to use a cellular solution in the BCA. The total costs that were assumed in the BCA for cellular backhauling were $3,578,978 ($2022) for the entire 20-year period.

A private fiber backhaul solution has been proposed through the Electric ISR Docket No. 22-53-EL, primarily for operations to satisfy real-time SCADA and system protection needs. If that is approved, there could be an opportunity to replace the AMF cellular backhaul and the associated on-going costs, where available and feasible. The transition to a private fiber network for AMF backhaul was not quantified in the AMF BCA and an analysis was not performed to determine what it would cost for a full fiber deployment to serve AMF meters.

Please also see the Company's responses to PUC 1-27 and PUC 1-28 for additional information.

Prepared by or under the supervision: Wanda Reder

PUC 1-16
IT Infrastructure

Request:

Regarding the IT infrastructure investments. Please provide a description of each one of the specific IT infrastructure investments reflected in the budgets for each of the five years. Please also describe the function of each IT project and its relationship, if any, to the AMF operations.

Response:

See the table below showing the description and function of the IT infrastructure investments and their relationship to AMF operations.

IT Infrastructure			
Investment	**Investment Period**	**Function**	**Relation to AMF**
Enterprise Integration Platform/Enterprise Network Model	4/23 - 3/29	An IT platform that includes a topical representation of the power system and its connectivity, enabling power system analysis to make operating and planning decisions based upon information that is available in real-time due to the exchange of information between systems, services and devices.	Incorporates granular data from AMF meters in the Network Model
Cybersecurity Services	4/23 - 3/29	IT services to protect customers and electric grid operations from a vast array of threats from new vectors as more devices, including third-party devices, are connected and integrated with utility operations.	GMP and AMF utilize common governance that was included in both filings: Cybersecurity, Data Privacy and Data Governance Plan
Data Management/Data Storage	4/23 - 3/29	IT platform to house internal and external data (e.g., asset, meter, land development, weather, real estate) that will ensure the proper data are made available for	Incorporates granular data from AMF meters, operational alarms and information

PUC 1-16, page 2
IT Infrastructure

IT Infrastructure			
Investment	**Investment Period**	**Function**	**Relation to AMF**
		analytics and that these data are properly controlled.	useful for system analytics
IT Equipment	4/23 - 3/29	Equipment needed to support the GMP data management, data storage and cybersecurity systems	No relationship to AMF
Network Management	4/23 - 3/29	IT communications technologies that collect meter and T&D system data to support AMF and the integrated modern grid.	Will include data from AMF RF mesh network as it relates to the overall Company communication architecture
Planning Tools	4/23 - 3/29	The plan includes investments for operational planning and engineering tools necessary to model and evaluate the distribution system under steady-state and dynamic conditions. This includes three phase load flow, stability, contingency analysis, system restoration modeling, relay modeling, waveform analysis and other key tools for system operations and planning.	Operational planning engineering tools use granular data from AMF meters as an input for steady state and dynamic analysis.

Prepared by or under the supervision: Wanda Reder

PUC 1-17
Climate Mandates and DER Penetration

Request:

Referring to the testimony of Mr. Labarre at Bates page 6, where he appears to express a concern that the distribution system could become "an impediment to the State in meeting its Climate Mandates." Please explain how the distribution system could become an impediment to the State meeting its climate mandates.

Response:

Grid modernization enables the Company to manage the electric distribution system more granularly considering a range of distributed energy resources ("DER") adoption levels, which are accelerated by the Climate Mandates.[1] As discussed in Sections 1.5 and 1.6 of the GMP (Bates Pages 16-17), enabling DER adoption, in particular renewable distributed generation, electric vehicles ("EV"), and electric heat pump adoption, will enable customers to reduce their overall carbon footprint, including reducing transportation-related emissions that make up 40% of the State's carbon dioxide emissions.[2]

Meeting the Climate Mandates requires a significant amount of additional DER, however, interconnecting DER into the existing electric distribution system infrastructure is becoming increasingly complex and expensive, resulting in projects being abandoned. Grid modernization will enable much more efficient use of the existing and planned distribution system, allowing the DERs needed for Climate Mandates to interconnect for a reasonable cost and within a reasonable time frame.

Without grid modernization, the distribution system has limited visibility and control. With this limited visibility and control, DER interconnection and operation cannot be optimized. This will result in increasing interconnection costs and increasing interconnection study timelines. Furthermore, renewable generation and unmanaged EV charging can have dramatically different daily load cycles, which can lead to significant load to generation mismatch. This mismatch can lead to renewable generation curtailment, which with the increased interconnection costs and

[1] As used in the GMP, the term "Climate Mandates" refers to the following statutory requirements: (1) 2021 Act on Climate, which 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; and (ii) the 2022 amendments to the Renewable Energy Standard, which 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.

[2] See U.S. Energy Information Administration, 2017 Data, Energy-Related CO2 Emission Data Tables, at Table 34 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/

Climate Mandates and DER Penetration

timelines described above would be an impediment to the State in meeting its Climate Mandates. Without grid modernization, the clean energy transition cannot happen at the pace and magnitude that is set forth in the Climate Mandates.

Prepared by or under the supervision: Alan LaBarre

PUC 1-18
Climate Mandates and DER Penetration

Request:

Referring to the Testimony of Mr. Labarre at Bates page 7, the Company states that "Rhode Island has one of the highest DER saturation rates in the country."

(a) Please define DER in this sentence.
(b) Please also provide a citation for the statement.
(c) What is the level of DER saturation cited by the Company?
(d) Please indicate whether the Company has included in its level of saturation DER installations that are connected directly to the transmission system through a distribution line serving only the DER facility. If so, please indicate what the level of DER saturation is net of those facilities.

Response:

(a) The DER referred to in this sentence is photovoltaic generation.

(b) The citation for this statement is:
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_02_b
The solar values presented in this sheet can be divided by each state's square miles to find saturation.

(c) Based on February 2022 data, Rhode Island has approximately 0.53 solar megawatts per square mile.

(d) The Energy Information Administration ("EIA") data does not specifically categorize solar generation connected to the transmission system and distribution system. The EIA data does identify "Utility Scale Facilities - Solar Photovoltaic (>=1MW)" and "Small Scale Capacity (<1MW)". Excluding Solar Photovoltaic (>=1MW) results in a Rhode Island value of 0.31 solar megawatts per square mile.

Prepared by or under the supervision: Alan LaBarre

PUC 1-19
Climate Mandates and DER Penetration

Request:

Please explain all the reliability issues, if any, that the Company has experienced to date from the installation of DER which is causing problems on the system that the Company has been unable to reasonably address.

Response:

There are no specific reliability issues that the Company is aware of and has experienced to date from the installation of DER that the Company has been unable to reasonably address. The Company has identified emerging issues that can affect reliability, including protection desensitization, load masking, and generation intermittency.

See Sections 2.5, 5.1, Attachment D and Attachment G to the Grid Modernization Plan.

PUC 1-20

Defining "short term" and "long term"

Request:

Referring to the testimony of the witness panel at Bates pages 50-51, there is a statement: "Each and every proposed investment, including the O&M activities, is reasonably needed to maintain safe and reliable distribution service over the short and long term." Please define what the panel means by "short term" and "long term."

Response:

The Revenue Decoupling Statute, R.I. Gen. Laws § 39-1-27.7.1, requires the Company to file a proposed plan and for the Commission to approve the plan "if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service ***over the short and long term."*** (Emphasis added.) The terms "short and long term" are not expressly defined in statute. The Company generally considers the short term to be one to five years and the long term to be beyond five years.

Prepared by or under the supervision: Nicole Begnal

PUC 1-21
Risk Scoring

Request:

On Bates pages 84-85, the plan states: "A project risk score is assigned to each project and considers key performance areas such as safety, reliability, and environmental, while also accounting for criticality." In the same paragraph, it states: "The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project."

(a) Please provide any internal guidance documents which provide direction or instruction regarding the criteria to be employed in performing the risk score analysis.

(b) Please provide a list of all projects proposed in the current ISR plan, along with the applicable risk score. Please list the projects by name, description, total proposed cost, and risk score.

(c) Did the Company establish a risk score for the Grid Modernization projects? If not, please perform a risk score analysis for each of the sub-categories of Grid Modernization projects that are listed in Attachment 3 at Bates page 115.

Response:

Although the Company reviewed risks when including projects into the FY 2024 ISR Plan, the Company did not use the legacy scoring approach previously employed under National Grid USA ("National Grid") ownership, and this language should be removed from the ISR Plan. That legacy scoring approach was used to drive consistency of risk evaluation and comparison across a multi-jurisdiction Company in which projects originated from different engineering and operation teams. Unlike National Grid, the Rhode Island Energy team is focused on one jurisdiction, and projects originate from the same engineering and operation teams which organically provides a consistent evaluation and comparison process. In lieu of a formal, cumbersome evaluation, discussions around risk, along with other factors that influence execution, were held internally with various teams, such as operations, engineering, and investment planning to help determine the prioritization of projects incorporated into the work plan. In addition to this being a legacy practice, not adopted by Rhode Island Energy, the Company would not have developed a separate risk score for each Grid Modernization investments as they are highly integrated and dependent on one another to deliver benefits as described in the Grid Modernization Plan.

Prepared by or under the supervision: Nicole Begnal

PUC 1-22

Classification of Grid Modernization as "Non-Discretionary"

Request:

For what purpose does the Company seek to categorize Grid Modernization as mandatory? What practical difference does it make to the Company if Grid Modernization is classified as discretionary instead of non-discretionary? Please explain.

Response:

The Company seeks to categorize the grid modernization investments as non-discretionary as that term relates to the Infrastructure, Safety, and Reliability ("ISR") filing. Please see the Company's response to PUC 1-25 as to why non-discretionary does not necessarily mean mandatory.

A non-discretionary capital investment is defined within the ISR Provision, R.I.P.U.C. No. 2199 ("Tariff"), as a "capital investment related to the Company's commitment to meet statutory and/or regulatory obligations." The Company's proposed grid modernization investments reflect the Company's commitment to meeting the relevant statutory obligations. (Please see the Company's response to PUC 1-23 for the relevant statutory obligations.) Accordingly, it is appropriate to categorize the grid modernization investments as non-discretionary.

From a practical manner, under either classification, the grid modernization investments are reasonably needed to maintain safe and reliable distribution service over the short- and long-term, and are appropriate for inclusion in the Electric ISR Plan. However, the Company believes the appropriate classification under the Tariff is non-discretionary.

From a tariff standpoint, the distinction between discretionary and non-discretionary capital investments is reflected in the definitions below.

"Discretionary Capital Investment" shall mean capital investment, other than 'NonDiscretionary' Capital Investment defined below, approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the

PUC 1-22
Classification of Grid Modernization as "Non-Discretionary"

lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

PUC 1-23
Classification of Grid Modernization as "Non-Discretionary"

Request:

For each project proposal under the category of Grid Modernization, please explain how each one is required by a legal, regulatory code, or other applicable requirement, if any. In making this determination for each project proposal, please distinguish between (i) projects that must be completed in order to comply with a specific law or regulation that is directly imposed on the Company from (ii) projects that the Company believes will enhance reliable service in the future but are not driven by a specific legal requirement, the non-compliance with which would place the Company in violation of law or regulations.

Response:

As indicated in the Company's response to PUC 1-22, the Infrastructure, Safety, and Reliability ("ISR") Provision, R.I.P.U.C. No. 2199 ("Tariff"), defines a non-discretionary capital investment as a "capital investment related to the Company's commitment to meet statutory and/or regulatory obligations." All of the grid modernization investments proposed in the Electric ISR Plan reflect the Company's commitment to meet statutory and regulatory obligations and, therefore, are appropriately classified. Please see the bullets below for a list of applicable statutes and state regulations. Since all of the grid modernization components work together and are integrated to achieve optimum benefits for customers, each investment is an integral contributor to effectuating the below laws and regulations. For more specificity, please see Attachment PUC 1-23.

- R.I. Gen. Laws § 39-2-1(a) which states that "[e]very public utility is required to furnish safe, reasonable, and adequate services and facilities…"

- The Act on Climate, R.I. Gen. Laws § 42-6.2-1 et seq., which sets forth greenhouse gas emissions reduction mandates[1];

- R.I. Gen. Laws § 39-26.3-4.1(d) which states that, in regard to interconnections of distributed generation, "…[a]ll electric distribution company system modifications must be completed by the date which is the later of: (1) [n]o longer than two hundred seventy (270) calendar days, or three hundred sixty (360) calendar days if substation work is necessary, from the

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[1] While the 2021 Act on Climate does not place any immediate obligations on the Company, it is not unreasonable to expect, given the utility's role in the transition of the energy system and its relationship to climate change, that rules and regulations that may be effectuated pursuant to the Act on Climate in the future will apply to the Company. See R.I. Gen. Laws § 42-6.2-8 (" Each [state] agency shall have the authority to promulgate rules and regulations necessary to meet the greenhouse gas emission reduction mandate established by § 42-6.2-9.").

PUC 1-23, page 2
Classification of Grid Modernization as "Non-Discretionary"

date of the electric distribution company's receipt of the interconnecting, renewable energy customer's executed interconnection service agreement…";

- The Renewable Energy Standard, R.I. Gen. Laws § 39-26-1 et seq., and associated state regulation entitled Implementation of a Renewable Energy Standard, 810-RICR-40-05-2, which require obligated entities, such as electric utility distribution companies supplying last resort service, to obtain a certain percentage of supply from new renewable energy resources and existing renewable energy resources; and

- State regulation entitled Standards for Electric Utilities, 815-RICR-30-00-1.4, which set forth voltage standards that must be maintained by the utility.

The Company's commitment to effectuating and complying with the above laws and regulations is unwavering and, therefore, the Company will seek alternative approaches to avoid noncompliance if the grid modernization projects are not completed. The Company would not classify the investments as (i) projects that must be completed in order to comply with a specific law or regulation that is directly imposed on the Company. However, as explained in the Company's response to PUC 1-25, an alternative approach that forgoes all or a portion of the proposed grid modernization investments would place the Company in a reactive position to effectuate and comply with the law and state regulations. This would likely result in higher costs to customers over the long term and be an impediment to the efficient interconnection of DER. The Company also would not classify the investments solely as (ii) projects that will enhance reliable service in the future. The grid modernization investments are needed today to maintain safe and reliable service as the electric distribution system continues to evolve and distributed energy resources continue to proliferate, as discussed in the Company's Grid Modernization Plan and in the Company's response to PUC 1-25.

Prepared by or under the supervision: Kathy Castro and Wanda Reder

Law/Statute/Regulation	Related GMP Functionalities
· R.I. Gen. Laws § 39-2-1(a) which states that "[e]very public utility is required to furnish safe, reasonable, and adequate services and facilities…"	ADMS / DERMS Advanced
	Advanced Reclosers
	DER Monitor/Manage
	Electromechanical Relay Repl Program
	Fiber Network
	IT Infrastructure
	Mobile Dispatch
	Smart Caps and Regs
· The Act on Climate, R.I. Gen. Laws § 42-6.2-1 et seq., which sets forth greenhouse gas emissions reduction mandates[1];	ADMS / DERMS Advanced
	Advanced Reclosers
	DER Monitor/Manage
	Fiber Network
	IT Infrastructure
	Smart Caps and Regs
· R.I. Gen. Laws § 39-26.3-4.1(d) which states that, in regard to interconnections of distributed generation, "…[a]ll electric distribution company system modifications must be completed by the date which is the later of: (1) [n]o longer than two hundred seventy (270) calendar days, or three hundred sixty (360) calendar days if substation work is necessary, from the date of the electric distribution company's receipt of the interconnecting, renewable energy customer's executed interconnection service agreement…";	ADMS / DERMS Advanced
	Advanced Reclosers
	DER Monitor/Manage
	Fiber Network
	IT Infrastructure
	Smart Caps and Regs
· The Renewable Energy Standard, R.I. Gen. Laws § 39-26-1 et seq., and associated state regulation entitled Implementation of a Renewable Energy Standard, 810-RICR-40-05-2, which require obligated entities, such as electric utility distribution companies supplying last resort service, to obtain a certain percentage of supply from new renewable energy resources and existing renewable energy resources; and	ADMS / DERMS Advanced
	Advanced Reclosers
	DER Monitor/Manage
	Fiber Network
	IT Infrastructure
	Smart Caps and Regs
· State regulation entitled Standards for Electric Utilities, 815-RICR-30-00-1.4, which set forth voltage standards that must be maintained by the utility.	ADMS / DERMS Advanced
	Advanced Reclosers (as a sensor)
	DER Monitor/Manage
	Fiber Network
	IT Infrastructure
	Smart Caps and Regs

PUC 1-24

Classification of Grid Modernization as "Non-Discretionary"

Request:

On Bates page 32, the testimony asserts that the $81.9 million of Grid Modernization investments are considered non-discretionary and mandatory "because they are driven by our statutory requirements to provide safe and reliable service." Conversely, please identify all the investments, if any, in the discretionary category of "System Capacity & Performance" listed in Attachment 3 that are not needed to meet the Company's legal requirements to provide safe and reliable service. Please explain why in each instance.

Response:

The Company believes that the System Capacity & Performance investments are reasonably needed to provide safe and reliable service and all of the investments contribute to meeting the Company's legal requirements. In terms of classification, System Capacity & Performance work has historically been included in the discretionary category and the Company elected not to disturb that classification in this year's proposed Plan.

The System Capacity & Performance investments are critical to addressing load constraints caused by the existing and growing and/or shifting demands of customers. To that end, all of the investments are needed to provide safe and reliable service. Please see Bates page 101-106 in the Plan for further explanation on the need for the System Capacity & Performance investments in Attachment 3.

Prepared by or under the supervision: Nicole Begnal

PUC 1-25
Questions Asked in AMF Docket No. 22-49-EL
Non-Discretionary/Discretionary

Request:

Please reconcile (i) the Company's position that Grid Modernization is a "non-discretionary" component within the Electric ISR filing (Docket No. 22-53-EL) that is required by statute (Bates page 32 of the ISR filing), with (ii) the position in [the AMF case] that the Company will choose not to go forward for financial reasons with AMF unless the Company obtains timely recovery of the full cost of AMF. In other words, how can Grid Modernization and AMF be respectively mandatory and optional at the same time, when AMF is foundational and integral to Grid Modernization (see Business Case, Section 4)?

Response:

The Company does not view either advanced metering functionality ("AMF") or the grid modernization investments as mandatory or optional, as framed in this request. Rather, the Company's position is that both are necessary investments to ensure that the Company can most effectively and efficiently maintain safe and reliable service as the electric distribution system continues to evolve and distributed energy resources ("DER") continue to proliferate. The Company, however, recognizes that, if the Public Utilities Commission ("PUC") does not agree and, therefore, does not approve its proposals, including for cost recovery, then it will need to pursue an alternative path. As described herein, the Company expects that the alternative pathways available will result in sub-optimal performance and increased expense overall.

As indicated in the Company's response to PUC 1-22, a non-discretionary capital investment is defined within the Infrastructure, Safety, and Reliability ("ISR") Provision, R.I.P.U.C. No. 2199, as a "capital investment related to the Company's commitment to meet statutory and/or regulatory obligations." The Company's proposed grid modernization investments reflect the Company's commitment to meeting the relevant statutory and regulatory obligations. (Please see the Company's response to PUC 1-23 for the relevant statutory and regulatory obligations.) If presented in the ISR, AMF would fall under the same classification. The Company's commitment to meeting statutory and regulatory obligations is unwavering; however, the approach is contingent upon regulatory directives and financial risk to the Company.
In this case, the Company's proposed grid modernization investments represent the most beneficial and cost-effective plan to satisfy the Company's legal obligations and further the Company's commitment to ensuring that the State can effectuate its statutory obligations pursuant to the 2021 Act on Climate and the 2022 amendments to the Renewable Energy Standard. If AMF is approved and instituted, the benefits of grid modernization would be enhanced, and the optimal functionality of the grid modernization investments would be realized.

Prepared by or under the supervision: Wanda Reder and Kathy Castro

PUC 1-25, page 2
Questions Asked in AMF Docket No. 22-49-EL
Non-Discretionary/Discretionary

An alternative approach that forgoes all or a portion of the proposed grid modernization investments or forgoes AMF would place the Company in a reactive position, which means the Company would need to implement other less cost-effective alternatives in piecemeal to address the changes occurring on the electric distribution system This would likely result in higher costs to customers over the long term and be an impediment to the efficient interconnection of DER.

Prepared by or under the supervision: Wanda Reder and Kathy Castro

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PUC 1-26
Questions Asked in AMF Docket No. 22-49-EL
DER/Monitor/Manage

Request:

Please compare (1) the assertion in the testimony of Walnock & Reder, p. 26 of 84 (AMF Docket), stating:

"In short, AMR technology cannot retrieve metering data frequently enough to provide the visibility to operate the electric distribution system safely and reliably in a future that includes the level of DER integration necessary to achieve the State's Climate Mandates"

with

(2) the description of the "DER/Monitor/Manage" activity in the current Electric ISR Docket No. 22-53-EL, in which Ms. Reder is a panel witness listed on pre-filed testimony, stating:

"DER/Monitor/Manage enables visibility of DERs and the ability to manage them. This management ranges from ramping operations to full curtailment of an individual DER output if needed, for distribution safety or reliability purposes." (p. 32 of 39)

(a) Which technology or activity is providing the visibility to manage the DER: the AMF, the DER/Monitor/Manage, or both working together? Please explain. To the extent the answer is that the visibility is provided by both working together, please explain the level of visibility provided by each.

(b) Is there a proposal to invest or incur costs to be recovered in rates from the DER/Monitor/Manage activity in either the proposed Advanced Metering Functionality Provision, an Electric ISR filing, or the next distribution rate case? If so, please identify the costs and timing, including distinguishing between O&M and capex.

(c) If both AMF and the DER/Monitor/Manage activity are needed to work together to achieve the needed visibility, are any of the costs associated with DER/Monitor/Manage included in the BCA? If so, please quantify. If not, please explain why not.

Response:

(a) Both AMF and DER Monitor/Manage provide added visibility for DER operations. AMF provides visibility at the point where the customer connects to the Company where bi-directional metering capability measures energy used, and excess energy produced.

PUC 1-26, page 2

Questions Asked in AMF Docket No. 22-49-EL

DER/Monitor/Manage

(b) Granular and timely customer load data from AMF meters supports more accurate load-flow calculations, enabling better system power flow and voltage profile system visibility where actions can be initiated through the ADMS/DERMs software platform to mitigate violations and to optimize operations. Types of information that could be available for DER integration from AMF are load profiles, peak-demand, hosting capacity, beneficial DER locations, interconnection queue, and voltage / thermal limits. DER Monitor/Manage provides the added ability to visualize and manage DER at the inverter, located behind the meter, where direct current is being converted to alternating current for customer use or for export. DER Monitor/Manage provides an opportunity to more fully integrate DER with the distribution system by providing functionality such as increasing hosting capacity, reducing curtailments, and assisting in balancing load and generation through the ADMS/DERMS software platform. For additional information on DER Monitor/ Manage, see Attachment G in the Grid Modernization Plan that was filed by the Company on December 30, 2022, and which has been filed in this docket as Attachment DIV 1-36-5.

There is a proposal to pursue DER Monitor/Manage in the Grid Modernization Plan and the associated Electric ISR filing The O&M and capex costs and timing are summarized below as reflected in Section 6 (Figure 6.4 – Bates page 129) and 8 (Figure 8.21- Bates page 194) of the Grid Modernization Plan. DER Monitor/Manage functionality also assumes any additional approvals necessary to implement it and the availability of ADMS/DERMS.

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total DER Monitor Manage Cash Flow	$ -	$ -	$ -	$ 2,288,076	$ 4,043,598	$ 4,414,290	**$ 10,745,964**

Program Category	Project Costs (000's)				Future Project Costs	Operating Costs		Total All BCA Costs (Nominal)	Total All BCA Costs (NPV)
	Install	Remove	OPEX	Total		RTB OPEX	RTB Telecom		
Total DER Monitor Manage	$ 10.7	$ -	$ -	$ 10.7	$ 103.3	$ 14.0	$ -	$ 128.0	$ 57.8

(c) Yes, AMF and DER Monitor/Manage work together to achieve the needed visibility. The Company did not include costs or benefits of DER Monitor / Manage in the AMF BCA because DER Monitor/Manage is not being proposed as part of the AMF Business Case. As more fully explained in the GMP, DER Monitor/Manage is a strategically important GMP functionality because it enables the visibility of DER and the ability to fully integrate DER into the electric distribution system. Accordingly, the costs and benefits of DER Monitor/Manage were included in the GMP.

Prepared by or under the supervision: Wanda Reder

PUC 1-27
Questions Asked in AMF Docket No. 22-49-EL
Fiber Investments

Request:

In the current Electric ISR Docket No. 22-53-EL, Attachment 3 on Bates page 115 indicates investment in a fiber network to be $19.4 million over a 21-month period spanning CY 2023 and CY 2024 and more than $60 million over a 5-year period through CY 2027. In addition, the following statement appears in the pre-filed testimony (Bates page 46):

"Q. What are the fiber investments?

A. Fiber investments are proposed to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul data from other installed grid modernization investments and AMF smart meters. This technology is needed to accommodate the vast quantity of operational data required for GMP and AMF. The network will provide security, speed, and bandwidth to achieve the required functionality and to achieve cost-effective benefits." (emphasis added)

(a) If the fiber is "needed to accommodate" the back haul of AMF data, are the referenced fiber investments necessary to achieve any of the benefits included in the BCA for the AMF Business Case at the levels assumed in the BCA? If so, please identify and quantify the amount of the benefits in the BCA that cannot be achieved through AMF without the fiber investments.

(b) Is there an allocation of the cost of the fiber investment to AMF in the BCA? If yes, please quantify. If not, and the assertion in the ISR filing is accurate that the fiber technology is "needed" to accommodate the vast quantity of operational data required for GMP and AMF, please explain why such an allocation (allocated between AMF and other GMP functions) should not be considered as a cost of the AMF project in the BCA.

Response:

(a) The referenced fiber investments are not necessary to achieve the benefits included in the BCA for the AMF Business Case at the levels assumed in the BCA. The benefits can be achieved by the leased cellular costs that have been included for the backhaul.

Prepared by or under the supervision: Wanda Reder

PUC 1-27, page 2

Questions Asked in AMF Docket No. 22-49-EL

Fiber Investments

(b) No. There is not an allocation of the cost of the fiber investment to AMF in the BCA. The private fiber backhaul solution that is included in the Foundational Investments in the GMP is primarily for operations to satisfy real-time SCADA and system protection needs. If that is approved, there could be an opportunity in the future to replace some of the AMF cellular backhaul and the associated on-going costs, where available and feasible. The fiber was not included in the AMF BCA because the cellular backhaul is assumed to provide the functionality in the BCA for the project duration.

Prepared by or under the supervision: Wanda Reder

PUC 1-28
Questions Asked in AMF Docket No. 22-49-EL
Fiber Investments

Request:

In the current Electric ISR Docket No. 22-53-EL, the filing contains the following description on Bates page 95:

> "Fiber – This project proposes to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul GMP and AMF data. Leased cellular service has limited bandwidth and is subject to greater interference, especially during emergencies when communication is imperative. The 21-month planned spend is roughly 32% of the Distribution Fiber 5-year GMP plan." (emphasis added)

In contrast, in the AMF Business Case at Bates page 84, it discusses a back-hauling communication solution involving a "mesh-to-cellular" network, stating on Bates page 147:

> "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." (emphasis added)

This language quoted above appears to be taken nearly verbatim from the National Grid filing in Docket No. 5133. (See Bates page 147 of the National Grid Business Case)

(a) Please clarify and explain whether the Company intends to use (i) a mesh-to-cellular backhaul, (ii) the private fiber as referenced in the ISR filing quoted above, or (iii) some combination of both for AMF back-haul communications.

(b) If the Company intends to use private fiber for backhaul, as indicated in the Electric ISR filing, why did the Company not include the private fiber network as a component for the AMF deployment in the AMF case, instead of representing that "mesh-to-cellular" was the Company's proposed backhaul strategy?

Prepared by or under the supervision: Wanda Reder

PUC 1-28, page 2
Questions Asked in AMF Docket No. 22-49-EL
Fiber Investments

Response:

(a) For the AMF deployment, the Company intends to use a mesh-to-cellular backhaul, and it was included in the BCA for the AMF Business Case. Backhaul capability is needed as the AMF system is deployed starting as soon as 2024. There is a private fiber backhaul in the fiscal year ("FY") 2024 Electric Infrastructure, Safety and Reliability Plan ("FY 2024 Electric ISR Plan") assumed to be deployed throughout the years to substations completing at the end of 2028.

If that fiber investment is approved in the FY 2024 Electric ISR Plan and moves forward as scheduled for real-time operational needs, the cellular backhaul for AMF collectors and gateways that are substation based, could be replaced with fiber if it is feasible and as it becomes available. Cellular backhaul would continue for collectors and gateways that are not located in a substation. As described in the response to part b) below, the cost of the private fiber investment was included in the GMP Business Case; it was not included in the AMF Business Case.

(b) Mesh to cellular backhaul was assumed in the AMF Business Case because it will meet the project schedule requirements and there is certainty that it will be available when and where needed. Due to certainty of cellular backhaul availability and its capability to deliver the BCA benefits, it was assumed as the only backhaul in the AMF BCA throughout the entire analysis period. Grid operational needs are the main driver for the fiber backhaul. Please also see the Company's response to PUC 1-27 for additional explanation of the potential future benefits of fiber backhaul, and, to the extent that it becomes available where needed for AMF backhaul purposes, it may be utilized in the future, though difficult to quantify. For this reason, the Fiber backhaul cost and benefits were included in the GMP; there are no fiber allocations for backhaul to the AMF BCA.

Prepared by or under the supervision: Wanda Reder

PUC 1-29
Questions Asked in AMF Docket No. 22-49-EL
Meter Purchases

Request:

In the Electric ISR Docket No. 22-53-EL, Attachment 1 shows both the historical capital spending back to FY 2011 and the proposed spending for a 21-month period spanning CY 2023 and CY 2024. (see Bates page 110) The table indicates proposed spending on meters of $4.5 million over that period.

(a) Please explain why the Company is proposing this level of capital spending on the old technology meters over this 21-month period when the Company is proposing to replace all old technology meters with smart meters under the Company's proposed timeline by the end of CY 2025.

(b) Please also explain why the Company is forecasting meter expenditures exceeding $2.6 million per year for CY 2026 and CY 2027. (See Attachment 3 – Five-Year Budget; Bates page 115) Are these new AMF meters or the old technology?

Response: **Please also see PUC 3-31 in the AMF Docket No. 22-49-EL.**

The Company is responding to this question based on the supplemental budget for fiscal year ("FY") 2024 for the period April 1, 2023 through March 31, 2024 that it filed with the Public Utilities Commission on January 27, 2023 in light of the PUC's ruling at its January 20, 2023 Open Meeting.

a) Electric meter budgets were prepared and presented in the Electric ISR Docket No. 22-53-EL that maintain business-as-usual processes. With AMF Business Case approval, the processes and support of old electric meter technology will be transitioned accordingly; as a result, the proposed meter spending in the FY 2024 (April 1, 2023 – March 31, 2024) ISR would not necessarily be spent.

b) The forecasted meter expenditures of more than $2.6 million per year for FY 2027 and FY 2028 are for old AMR technology. As stated above, with AMF Business Case approval, the processes and support of old electric meter technology will be transitioned accordingly; as a result, the proposed meter spending in the FY 2027 and FY 2028 ISR would not necessarily be spent.

Prepared by or under the supervision: Wanda Reder

PUC 1-30
Grid Modernization Category

Request:

The Amended Settlement Agreement approved by the Commission in Docket No. 4770 included a bulleted list of requirements the Grid Modernization Plan. (Amended Settlement Agreement at Bates pages 51-52). For each bullet point requirement, please identify the Bates pages in the recently filed Grid Modernization Plan where each requirement was addressed/analyzed.

Response:

The Grid Modernization Plan includes Figure 1.1 that identifies the section within the plan that addresses the ASA requirement. Figure 1.1 is provided below with page numbers added as requested.

ASA Grid Modernization Terms	GMP or Other GMP Document Sections
1. Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document;	• Section 1.4: BCA Summary – Bates page 12
2. Explanation of the role of currently active programs ;	• Section 2.3: Current Grid Modernization Activities – Bates pages 32-34
3. Investments and technology deployments planned through the end of any proposed AMF implementation;	• Section 1 – Bates page 6 • Section 6 – Bates page 125 and 127
4. Functionalities to achieve the objectives;	• Section 3: Functionalities Needed to Transform the Grid – Bates pages 58-64
5. Review of options for candidate technologies to deliver those functionalities;	• Section 3 – Bates pages 58-64 • Section 4 – Bates pages 70-75 • Section 5 – Bates pages 101-109 • Attachment H Deployment Plan: all sections – Bates pages 287-308 • Updated AMF Business Case (separate filing)

Prepared by or under the supervision: Wanda Reder

PUC 1-30, page 2

Grid Modernization Category

ASA Grid Modernization Terms	GMP or Other GMP Document Sections
6. Transparent, updated benefit cost analyses that fully incorporate the Docket 4600 framework;	• Section 8: BCA Evaluation Under Docket 4600 Bates pages 170 - 205 • Attachment I: Benefit Cost Analysis Details
7. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;	• Section 6 – Bates pages 125 - 153 • Section 1.9 – Bates pages 24 - 28 • Attachment H Deployment Plan: all sections - Bates pages 287-308
8. A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term;	• Section 6.2: GMP Roadmap – Customer Enablement – Bates pages 126 - 128 • Section 6.6: GMP Roadmap – Other Future Solutions - Bates pages 154 - 155
9. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;	• Section 6.5: GMP Roadmap: Communications – Bates pages 150 - 151 • Attachment C - GMP Roadmap: Communications Solutions and Assumptions – Bates page 228 - 234
10. Explanation of congruency with grid modernization activities in New York and Massachusetts;	• Not applicable
11. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and	• Section 7.1: Managing Risk of Redundancy, Obsolescence, and Uncertainties – Bates page 159
12. A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation.	• Section 5 – Bates pages 89 - 105 • Section 3.5 GMP impacts to load management capability – Bates pages 67 - 69

Prepared by or under the supervision: Wanda Reder

PUC 1-31
Grid Modernization Category

Request:

For each component of the Grid Modernization spending category discussed on Bates pages 93-95 of Section 2 of the Electric Capital Plan, please cross-reference the spending to the relevant Bates pages in the recently filed Grid Modernization Plan.

Response:

The table below provides a cross reference to the Grid Modernization spending categories listed in Section 2 of the Electric Capital Plan with the relevant Bates pages in the Grid Modernization Plan.

	GMP Bates Pages
ADMS / DERMS Advanced	129 - 138, 193, 194-195, 291, 303
Advanced Reclosers	139 - 150, 193, 196-197, 291, 297
DER Monitor/Manage	129 - 138, 193, 194-195, 291, 305
Electromechanical Relay Repl Program	139 - 150, 193, 196-197, 291, 300
Fiber Network	150 - 153, 193, 197, 291, 308
IT Infrastructure	129 - 138, 193, 194-195, 291, 307
Mobile Dispatch	129 - 138, 193, 194-195, 291, 306
Smart Caps and Regs	139 - 150, 193, 196-197, 291, 295

Prepared by or under the supervision: Wanda Reder

PUC 1-32
Grid Modernization Category

Request:

For each component of the Grid Modernization spending category, please identify the current safety or reliability problem on the distribution the investment is intended to solve. If the investment is intended to solve an anticipated safety or reliability problem on the distribution system, please explain what the Company has assumed for the condition to exist on the system and the timeline for when the identified problem is projected to materialize.

Response:

Each Grid Modernization spending category or component is not intended to solve a specific safety or reliability problem. All the grid modernization investments collectively mitigate the emerging safety and reliability issues. For example, the advanced reclosers can provide data to an Advanced Distribution Management System ("ADMS") through a suitable fiber network, and that ADMS, paired with real-time loadflow, can be used to mitigate load masking and generation intermittency. Sensing and data provided by advanced capacitors also helps the ADMS mitigate emerging issues. Also see Sections 2.5, 5.1, 6.4, and Attachment G to the Grid Modernization Plan ("GMP"). Attachment D to the GMP illustrates how the issues are emerging now, identified during impact studies, resulting in DER size reductions. The Nasonville event, described in Section 2.5 of the GMP, also demonstrates current reliability problems that could be mitigated with Grid Modernization investments.

Section 5 of the GMP explains anticipated system issues as a result of the stated assumptions within this same section. The GMP studied specific years of 2030, 2040, and 2050. The modeling assumptions were carefully determined to sufficiently test the electric system for grid modernization versus no grid modernization options. While this was a suitable and fair method to test the viability of grid modernization, it is recognized that customer adoption of distributed generation, electric vehicles, and heat electrification can and does occur in a localized and concentrated manner. In other words, the timeline of localized issues cannot be predicted by the Company as they are driven by customer actions. Instead, Rhode Island Energy has provided several examples of how these localized and concentrated issues are happening now (Attachment D to the GMP).

Prepared by or under the supervision: Ryan Constable

PUC 1-33
Grid Modernization Category

Request:

The Company has area studies that predate the Grid Modernization Plan. The area studies resulted in recommended investments in the system. Has the Company analyzed the extent to which the Grid Modernization Plan might affect those proposed investments? Please explain or point to where in the recently filed Grid Modernization Plan that analysis was discussed.

Response:

Yes, Section 5.2 of the Grid Modernization Plan explains how the area study recommendations were incorporated into the grid modernization model. Also see the Company's response to Division 2-7.

PUC 1-34
Grid Modernization Category

Request:

The Company references reliable and resilient service on Bates page 6. What is the difference between reliability and resilience?

Response:

The industry definitions between reliability and resiliency can vary. Rhode Island Energy generally uses the term 'reliability' to refer to the day-to-day ability of the system to prevent interruptions and restore customers after an interruption and the term 'resiliency' to refer to the ability of the system to prevent interruptions and restore customers after an interruption during major events and storms.

Prepared by or under the supervision: Ryan Constable

PUC 1-35

Grid Modernization Category

Request:

Please provide the Company's definition of beneficial electrification. Please explain the extent to which the electrification is beneficial to (a) the safety and reliability of the electric system; (2) to electric customers; and (3) to the utility. Please discuss any assumptions included in the response.

Response:

Beneficial electrification is not a term defined by Rhode Island Energy. It is an industry term used to describe replacing direct fossil fuel use, such as home heating, with electricity in a way that reduces overall emissions and energy costs. It is often used in conjunction with the conversion of fossil fuel-based home heating with heat pumps.

Rhode Island Energy uses the term as defined by the industry and highlights how "beneficial electrification" can significantly change the electric distribution system. When using the term "beneficial electrification", Rhode Island Energy is not claiming that electrification is beneficial to (a) the safety and reliability of the electric system; (2) to electric customers; and (3) to the utility. Instead the Company claims that electrification can create a system "that is more dynamic, less predictable, and more complicated to manage to ensure safe and reliable electric distribution service."

PUC 1-36
Grid Modernization Category

Request:

On Bates page 9, the Company states that the FY 2024 Electric ISR Plan includes "the addition of foundational investments needed for grid modernization…consist[ing] of additional reclosers and reactive compensation and voltage management infrastructure." How do these investments differ from previously reviewed reclosers and VVO investment?

Response:

The previously reviewed reclosers and investments used in the VVO pilot have used a stand-alone architecture. The previous recloser investments consisted mainly of control upgrades. Although the previous control upgrades operate in a standalone manner, the recent upgrades are aligned with grid modernization recloser control types and can be incorporated into the proposed Advanced Distribution Management System ("ADMS") and Fault Location Isolation and Service Restoration ("FLISR") functionality. The grid modernization reclosers, which would be directly integrated into ADMS and FLISR, do include some upgrades to existing sites, but mainly consist of new recloser locations including feeder open tie points.

The previous VVO investments consisted of advanced capacitors and regulators, feeder sensors and a VVO/CVR control platform that operate on 45 feeders that have been deployed over the last 3-5 years. In contrast, the Foundational Investments use an integrated architecture where new AMF meters, advanced capacitors and regulators, microprocessor relays, reclosers and other voltage sensing devices are integrated into the ADMS VVO functionality to optimize the voltage profile. The grid modernization devices associated with the ADMS VVO system will be placed on the remaining feeders. Although the previous VVO stand-alone architecture will be removed, the previously installed field devices on the original 45 feeders will ultimately be incorporated into the proposed ADMS VVO system. Because there are thousands of points available per feeder located along it, the greater resolution lends itself toward higher accuracy, which is important as voltage fluctuation and profile uncertainty increases with more DER, and there is no need for additional feeder sensors.

Prepared by or under the supervision: Wanda Reder

PUC 1-37
Grid Modernization Category

Request:

For every component of the Grid Modernization category where the Company is seeking recovery in the FY 2024 ISR plan of O&M for grid modernization, please itemize each cost, the amount, and explain why, other than for I&M or Vegetation Management, the Commission should permit recovery of these O&M costs.

Response:

Following Rhode Island capital project structure, each investment program within the GMP was assigned a split between CAPEX (Install), CAPEX (Removal) and OPEX. The OPEX costs included in the FY 2024 ISR are based on the OPEX percentage split for each initial capital construction investment in the GMP category. See table below, showing the percentage splits for each category.

Solution	Yr1 (4/23 – 3/24)	Install % Of Investment	Remove % of Investment	O&M % of Investment
ADMS	$ 6,084	98%	1%	1%
IT Infrastructure	$ 22,584	98%	1%	1%
Mobile Dispatch	$ 1,091	98%	1%	1%
Cap Banks and Regs	$ 131,756	90%	8%	2%
Fiber	$ 112,526	98%	1%	1%
Recloser	$ 233,661	98%	1%	1%
Electromechanical Relays	$ 1,125,000	77%	15%	8%
	$ 1,632,702			

The $1.633M in O&M in the ISR relates to the O&M portion of the initial capital construction costs. It does not include any ongoing O&M for inspections, repairs or maintenance, nor does it cover any cellular costs related to the advanced field devices in the GMP. The Company believes that since the GMP O&M costs shown above are all directly related to the GMP capital costs included in the ISR that the GMP O&M costs should be recovered through the same mechanism as the capital costs.

Prepared by or under the supervision: Wanda Reder

PUC 1-37, page 2

Grid Modernization Category

Within the GMP, there are additional O&M costs for run the business for inspections, repairs and maintenance as well as the cost for cellular for the advanced field devices. See below for the complete breakdown of GMP costs as referenced in Figure 8.18 of the GMP.

Program Category	Project Costs (000's)				Future Project	Operating Costs		Total All BCA	Total All BCA
	Install	Remove	OPEX	Total	Costs	RTB OPEX	RTB Telecom	Costs (Nominal)	Costs (NPV)
Communications (Fiber)	$ 91.1	$ 0.9	$ 0.9	$ 93.0	$ -	$ 12.3	$ -	**$ 105.3**	**$ 86.2**
Advanced Field Devices	$ 191.4	$ 10.2	$ 5.3	$ 206.9	$ -	$ 26.1	$ 8.6	**$ 241.7**	**$ 194.1**
Operational Systems & Applications	$ 39.4	$ 0.3	$ 0.3	$ 40.0	$ 103.3	$ 38.7	$ -	**$ 182.0**	**$ 93.5**
Total All GMP	**$ 321.9**	**$ 11.4**	**$ 6.6**	**$ 339.9**	**$ 103.3**	**$ 77.1**	**$ 8.6**	**$ 529.0**	**$ 373.8**

Prepared by or under the supervision: Wanda Reder

PUC 1-38
Grid Modernization Category

Request:

Referencing Bates page 77, the Company suggests that Grid Modernization investments will allow operators to minimize curtailment of DERs. Please explain this statement including (a) what the Company means by curtailment; (b) who would be doing the curtailment; (c) whether curtailment is currently allowed under the Company's tariffs; and (d) a timeline of when the Company expects to need to curtail.

Response:

Section 5.7 of the Grid Modernization Plan ("GMP") explains DER curtailment issues in detail including how Grid Modernization investments will minimize curtailment. To summarize, grid modernization provides sensing, data, and control for much more refined curtailment capabilities.

a) Curtailment is any action that reduces the amount of electricity generated to maintain system stability and is predominantly used to address the balance between the supply of electricity and demand. The amount of curtailment and how it is performed is significantly different in a future that includes grid modernization as compared to one without grid modernization as explained in Section 5.7 of the GMP.

- No grid modernization: Without grid modernization, electric distribution system issues because of excess distributed generation ("DG") cannot be monitored or managed (*i.e.*, curtailed) in a granular manner. Therefore, seasonal limitations resulting in curtailment are necessary during the time of the year when the supply of electricity and demand is forecasted to be unbalanced. Figure 5.7 of the GMP illustrates the seasonal curtailment needs by 2030.

- Grid modernization: With grid modernization, DER curtailment will be minimized due to having situational awareness and the ability to manage DER output to achieve load-to-generation balance on a real-time basis. Examples of the actions that the Foundational Investments will enable to reduce and minimize load curtailment are as follows:

    - Management of Energy Storage to balance generation and load
    - Enable Time Varying Rates to shift load to periods of high generation (working with AMF)
    - Load shifting between feeders

PUC 1-38, page 2
Grid Modernization Category

b) Distribution System Operators will perform the curtailment, similar to ISO-NE transmission system operators.

c) Yes. Curtailment would be allowed under R.I. Gen. Laws § 39-2-1[1] which requires utilities to provide "safe, reasonable, and adequate services and facilities." Additionally, The Narragansett Electric Company Standards for Connecting Distributed Generation, R.I.P.U.C. No. 2258 ("Interconnection Tariff"), contains numerous provisions authorizing the Company to curtail or otherwise interrupt distributed generation to address the needs of the electric distribution system. *See*, *e.g.* Interconnection Tariff, § 7.1. The curtailment that would be enabled by the Grid Modernization investments would be accomplished through Company owned devices and Company managed programs. There is no tariff provision that currently allows the Company to directly control a DER inverter as contemplated by DER Monitor / Manage functionality within the GMP. Attachment G in the GMP, at Bates page 286, explains that Rhode Island Energy will be exploring the legal and regulatory issues and possible tariff revisions in the future.

d) In terms of a timeline for curtailment, the Company already encounters situations when it is needed on a localized basis. However, Rhode Island Energy addresses the immediate curtailment needs during a specific interconnection study. The applicant can downsize their facility or pay for increasingly costly interconnection facilities. If the applicant downsizes the facility, this results in permanent curtailment, which could affect the State's ability to achieve the Climate Mandates. Attachment D to the GMP includes specific cases of size reduction occurring during study.

   Significant curtailment would be needed by 2030 as indicated by the Distribution Study performed for the GMP. The state level analysis identifies the need for approximately 18% curtailment by 2030. and increases to approximately 40% by 2040. Figure 5.11 in the GMP, also included below, summarizes curtailment needs in 2030 and 2040 with and without grid modernization. This state level analysis was used to explore the curtailment differences between grid modernization and no grid modernization technologies. It should not be used as the need date for curtailment. As described above, there are curtailment needs now. Instead, the state level analysis should convey that curtailments needs will be wide spread by 2030.

[1] http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-2/39-2-1.htm

PUC 1-38, page 3

Grid Modernization Category

Figure 5.11: Curtailment as a Percentage (%) of Total DG Energy

Curtailment as a Percentage of Total DG Energy		
Case	**Percent of Annual Energy (%)**	
	2030	**2040**
No Grid Modernization	17.7%	40.4%
Grid Modernization	4.1%	17.6%
GM & Energy Shift	2.8%	5.1%
GM, Energy Shift & Energy Storage	0.7%	4.4%

Prepared by or under the supervision of: Wanda Reder

PUC 1-39
Grid Modernization Category

Request:

Does Pennsylvania or Kentucky have ADMS Basic or Advanced ADMS? If the response is only ADMS Basic, is there a proposal before the either Public Utility Commission or a plan to implement Advance ADMS in PPL's other service territories?

Response:

Pennsylvania has ADMS Basic and some aspects of ADMS Advanced, including DER Management and VoltVar control. There are long standing plans to continue to add functionality to ADMS in Pennsylvania consistent with the proposed functions being discussed in Rhode Island. The functionality will be implemented over several years based upon business needs and regulatory commitments. Kentucky is using a similar plan that first focuses on the implementation of ADMS Basic functionalities, advanced functions will then be implemented based on their needs and commitments to its regulatory bodies. When implemented, it will provide a consistent operating platform across all jurisdictions with shared visions, strategies, and support structures to reduce costs for each utility.

PUC 1-40
Grid Modernization Category

Request:

Please provide a list of the functionalities ADMS basic will provide compared to the functionalities of Advanced ADMS. Please also clearly identify which other "Grid Modernization" investments are needed to provide the functionality or whether the ADMS can provide any of the functionality without all of the additional Grid Modernization investments listed on Bates page 93.

Response:

A list of the functionalities ADMS Basic will provide compared to the functionalities of Advanced ADMS is provided in Section 6.3 of the Grid Modernization Plan ("GMP"), which was filed in Docket No. 22-56-EL and submitted in this docket as Attachment DIV 1-36-5. In the GMP, on Bates page 131, Figure 6.6 shows the Operational Functional Timeline for ADMS and is also shown below. The first two columns represent the functionality associated with ADMS Basic, which will be made available to Rhode Island Energy coincidental with the Transition Services Agreement ("TSA") exit in May 2024.[1] As shown below, ADMS Basic provides the following functionalities: Subnet Needs for TSA, Basic SCADA, Device Management, Device Cutovers, Load shed Tables (TMS), Subnet Needs for GMP, Basic OMS, Electronic Switching, Load Model (manual read), DMS Apps (FLISR) and Meter Reads (Ping & Last Gasp). On Bates page 133 of the GMP, Figure 6.7 describes each of these functionalities that will be available with ADMS Basic and is also provided below.

The functionality in the remaining columns in the ADMS and Operational Functionality Timeline (Figure 6.6 below) that end in 2025, 2026, 2027, 2028 and 2029+ represent functionality releases for Advanced ADMS. Definitions of each functionality included in Advanced ADMS was included in Figures 6.8-6.12, as Definitions of GMP-enabled Functionalities available with ADMS GMP in year 2, 3, 4, 5 and Future respectively.

Figures 6.8-6.12 are located on Bates pages 134-136 of the GMP and are provided below.

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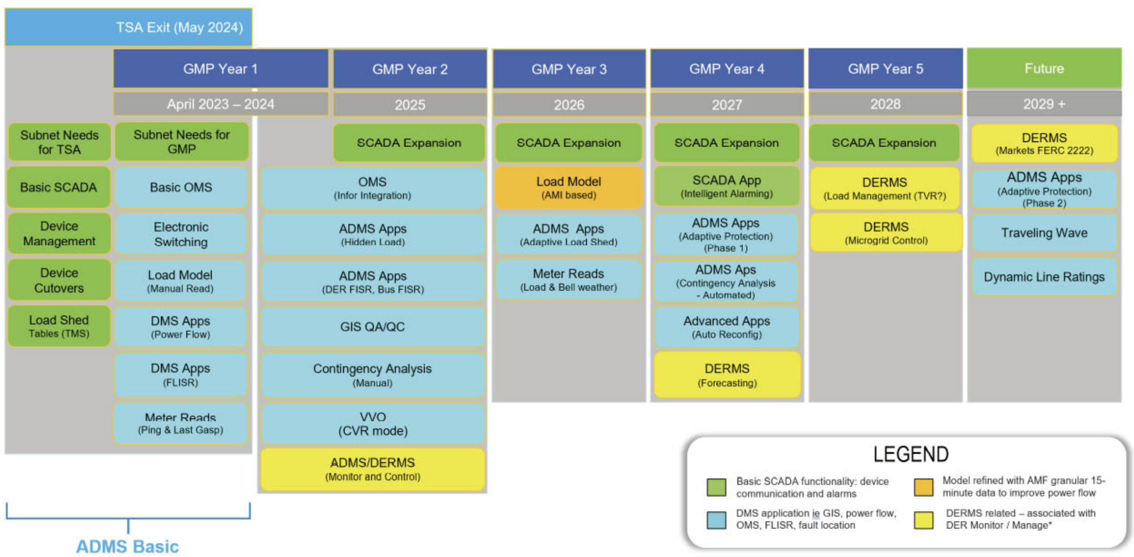
[1] The TSA is an agreement between National Grid USA Service Company, Inc. ("National Grid Service Company") and Rhode Island Energy where, among other things, National Grid Service Company operates and maintains its back-office systems for Rhode Island Energy customers for up to two years after the Acquisition. During this period, customers will have their operations supported with National Grid systems 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.

<u>PUC 1-40, page 2</u>

Grid Modernization Category

Figure 6.6: ADMS and Operational Functionality Timeline



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Grid Modernization Category

Figure 6.7: Definitions of GMP-enabled Functionalities available with ADMS Basic

ADMS Basic FUNCTIONALITY	WORKING DEFINITION
Subnet	Data concentrator device used to aggregate 200 PTR's (Capacitors and Voltage Regulators) to one device for consumption by ADMS SCADA
Basic SCADA	The hardware and software needed to support the monitoring alarming & control of telemetered field assets, both inside and outside station boundaries. Rhode Island Electric uses two systems: TMS for transmission assets and ADMS for distribution assets
Device Management	Database and UI used to manage the adds, deletes, and modifies of distribution telemetered assets
Device Cutovers	The work to program and convert all current SCADA devices to the PPL host systems
Load Shed	Software that controls the operation of circuit breakers to reduce load when called for by ISO-NE.
Basic OMS	Hardware and software needed to receive customer calls, predict to common devices, keep customers informed, and manage the execution of the work to restore/repair the issues. Does not include auto dispatching or remote dispatching
Electronic Switching	Application within ADMS that allows DCC personal to write, review, and execute switching orders electronically
Load Model (manual)	The customer load information and processes required to run distribution power flow (DPF). Based on the monthly usage reads
DMS Apps (FLISR)	The automated switching application with ADMS that determines outage locations, determines and ranks suitable switching options, and executes the most desirable based on a configurable set of criteria (Performance Index)
Meter Reads (Ping and Last Gasp)	Ability and connections between ADMS and AMF that brings real time meter information (Power Down & Power Up) to ADMS

PUC 1-40, page 4
Grid Modernization Category

Figure 6.8: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 2

ADMS FUNCTIONALITY GMP Year 2	WORKING DEFINITION
OMS (Infor Integration)	Adds the ability to send outage tickets to mobile units in field workers trucks and unlocks the ability to automatically dispatch to appropriate crews dependent on a configurable rule set
ADMS Apps (Hidden Load)	The modeling and software configuration within ADMS to understand the amount of load that is being masked by DER penetrations. Used in FLISR application and planned work study scenarios
ADMS Apps (DER FLISR & Bus FLISR)	The modeling and software configuration within ADMS to make available the ability of FLISR to account for the DER's that will NOT be on immediately following restoration. Also includes functionality to support FLISR plan creation and execution for substation bus outages – dependent on hardware and feeder offload availability
GIS (QA/QC)	The work required to validate the data integrity of the external distribution system network model to support voltage control
Contingency Analysis (manual)	Ability to study planned bus outages for risks associated with the switching required and to determine suitable alternate plans
VVO (CVR mode)	Voltage control application with ADMS that reduces distribution system voltage to the low side of the ANSI required band and optimizes the use of all distribution feeder voltage control assets
ADMS/DERMS (monitor & control)	The modeling and software required to connect to "behind the meter" asset inverters. Data used in ADMS DPF application and controls to allow for increased voltage control options and real power ramping to minimize DER curtailment

Figure 6.9: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 3

ADMS FUNCTIONALITY GMP Year 3	WORKING DEFINITION
Load Model (AMF based)	Enhanced ADMS load model based on AMF 15-minute reads
ADMS Apps (Adaptive Load Shed)	The modeling and configuration to enhance TMS load shed application to rank the feeders based on real time data and system configuration. Eliminates the need to manually manage load shed tables and schemes
Meter Reads (Load & Bell weather)	Ability of ADMS to read and make use of near real-time customer meter load and voltage information

PUC 1-40, page 5
Grid Modernization Category

Figure 6.10: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 4

ADMS FUNCTIONALITY GMP Year 4	WORKING DEFINITION
SCADA App (intelligent alarming)	Software and configuration process required to reduce the overall alarm fatigue caused by the introduction of multiple telemetered devices installed per feeder
ADMS Apps (Adaptive Protection P1)	Software and configuration to allow FLISR to select new pre-programmed settings groups when performing automated restoration switching
ADMS Apps Contingency Analysis (Automated)	Ability to automatically analyze planned bus outages for risks associated with the switching required and determine suitable alternate plans if required
ADMS (Auto - Reconfiguration)	Software and configuration within ADMS that detects voltage and load exceptions and determines suitable switching solutions to resolve the issue
DERMS (forecasting)	Software and configuration that perform DER and Customer Load forecasts for use by ADMS power flow and other distribution operations applications

Figure 6.11: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 5

ADMS FUNCTIONALITY GMP Year 5	WORKING DEFINITION
DERMS (load management TVR)	Software and configurations that send signals to customer assets based on Demand Response and Time Varying Rate programs
DERMS (Microgrid Control)	Software and configurations that monitor distribution system status and coordinate the start-up, operation, and shutdown of attached microgrids

Grid Modernization Category

Figure 6.12: Definitions of GMP-enabled Functionalities available with ADMS GMP Future

ADMS FUNCTIONALITY Future Term	WORKING DEFINITION
DERMS (FERC 2222)	Software and configurations that allow for full DSO (Distribution System Operator) functionality as ultimately defined by FERC 2222
ADMS Apps (Adaptive Protection P2)	Software and configuration to allow pre-defined distribution system conditions to initiate an automated protection review. If relay settings changes are needed; new relay files are produced and downloaded to the appropriate microprocessor relays
Traveling wave	Used for predictive failures (traveling wave fault protection)
Dynamic Line Ratings	Used to improve line operation capabilities dependent on real-time weather conditions (temperature, wind, etc.)

All of the "Grid Modernization" investments that are included in Bates page 93 of the ISR are needed in a fully integrated fashion to provide the described ADMS functionality. The integrated nature of these solutions is described in Section 4.2 of the GMP, Bates pages 71-72 organized into five integrated facets: (1) DER Monitor/Manage devices capable of capturing grid-edge data at defined intervals and supporting grid-edge applications. (2) advanced field devices including capacitors, regulators, and reclosers that are capable of communicating and receiving settings remotely; (3) interconnected secure communications consisting of cellular, two-way mesh communications network and IT infrastructure for transmitting the data and control signals that uses a cellular or fiber backhaul technology; (4) microprocessor relays and substation routers in the substation; and (5) an IT platform that is anchored with ADMS, peripheral systems and cybersecurity protections to securely and efficiently collect, validate, store and manage the data. ADMS alone is unable to provide the described functionality.

PUC 1-41

Grid Modernization Category

Request:

Please specifically explain whether the ADMS basic is incapable of providing functionality to include FLISR, VVO, Contingency Analysis, Hidden Load Identification, Adaptive Load Shed" and identify the "other key features." Please also identify where in the Grid Modernization Plan explanation of each of these functionalities is found.

Response:

ADMS Basic does include software functionality to support FLISR. It is incapable of providing software functionality that includes VVO, Contingency Analysis, Hidden Load Identification, and Adaptive Load Shed. The additional functionality becomes available with ADMS Advanced. See the response to PUC 1-40, which describes the ADMS functionalities. Additional detail for each of these functionalities is found at Bates pages 133-137 of the Grid Modernization Plan.

PUC 1-42
Grid Modernization Category

Request:

Can advanced reclosers provide load control and more visibility on the system with ADMS basic?

Response:

Yes. Advanced reclosers in combination with ADMS basic will provide load control and near real-time power measurements to automatically isolate faults and restore service to better manage capacity along individual feeders. Advanced Reclosers communicate to ADMS Basic to provide operators with system visibility. ADMS provides logic and acts as a human-machine interface for operator visibility where (as described in the Grid Modernization Plan at Bates page 137) the Fault Location Isolation and Service Restoration application included in ADMS Basic, relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) communications to each device; and (3) Advanced Field Devices (reclosers) to detect faults, isolate where possible and operate when commanded by ADMS.

Prepared by or under the supervision: Wanda Reder

PUC 1-43
Grid Modernization Category

Request:

Referencing DER Monitor Managed, who will be responsible for the installation of smart inverters on DERs? Will these smart inverters be required as part of interconnection requirements? If so, why are they not a customer-specific expense?

Response:

Smart inverters are inherent in the design of distributed energy resources ("DER"). Responsibility for the installation of the DER and the smart inverters that are integral to them are at the customers' expense. Inverter requirements are defined in the interconnection requirements.

As described in the GMP, Attachment G, DER Monitor / Manage Approach and Functionality, the Company envisions that DER Monitor/Manage would apply to DER interconnected with its distribution system by proactively implementing IEEE 1547-2018 requiring DER smart inverters to be certified to the related Underwriters Laboratories ("UL") Standard 1741, "Inverters, Converters and Controllers for use in Independent Power Systems" ("UL Standard 1741"). Customers applying to interconnect new DER will be required to: (1) use Company-approved smart inverters that are compliant with IEEE 1547-2018 certified with UL Standard 1741 and install devices that enable the Company to monitor and proactively manage DER. This will enable the Company to better integrate, monitor, and manage DER. Qualifying DER system interconnections are envisioned to be equipped with: (1) smart inverters located at the customer premise; (2) DER management devices that interface to the smart inverter; and (3) local communication interfaces that utilize communication protocols that meet IEEE 1547-2018. Unlike the smart inverters, the DER management devices that interface with the qualified smart inverters are proposed to be the responsibility of the Company and have been included in the GMP BCA.

Prepared by or under the supervision: Wanda Reder

PUC 1-44
Misc.

Request:

What does it mean that the Company views planning criteria as a "bright line"? (Bates page 27).

Response:

The Company considers violation of its planning criteria thresholds as a bright red line that it will not knowingly cross by unnecessarily deferring capital solutions that are required to ensure the safety and reliability of the system.

Prepared by or under the supervision: Kathy Castro

PUC 1-45
Misc.

Request:

Please explain how the passage of SB 2022-2771 (2022 P.L. Ch. 341) http://webserver.rilin.state.ri.us/PublicLaws/law22/law22341.htm has impacted the cost allocation between those customers and electric ratepayers, if at all. If there is an impact, please explain how the Company has accounted for that change in the Customer Request/Public Requirement category, resulting revenue requirement, and rate base calculation.

Response:

The Company will receive less reimbursement for Rhode Island Department of Transportation ("RIDOT") requested work after the passage of SB 2022-2771 (2022 P.L. Ch. 341). RIDOT projects are categorized as Non-Discretionary, Public Requirements work. Reduced customer contributions will increase net spending (capital, cost of removal and operating expense) resulting in an increase in the revenue requirement.

The Company increased its reserve for public requirements projects in the FY 2024 ISR Plan, resulting in slight increases to rate base and the revenue requirement, but as this is a relatively new law, the Company has not seen the full impacts of the reimbursement change. As RIDOT projects progress, the Company will keep the Division of Public Utilities and Carriers and the Public Utilities Commission updated through the submission of its quarterly reports.

Prepared by or under the supervision: Nicole Begnal

PUC 1-46
Misc.

Request:

Referencing Bates page 67, please explain how the annual capacity review is incorporated into the Company's heat map.

Response:

During the annual capacity review, each feeder's annual peak load is recorded. Forecasted growth rates are then applied to each feeder's annual peak load to find each feeder's projected annual peak load for the following year and subsequent years. Once the annual capacity review is complete, the following feeder data is compiled each year as follows:

Data Field	Description	Calculation
Planning Area	Planning area where the feeder is located	
Feeder	Feeder number the company uses to identify the feeder	
Substation	Substation that supplies the feeder	
Operating Voltage (kV)	Operating voltage of the feeder	
Summer Rating (Amps)	Summer normal rating of the feeder's limiting element in amps. The feeder's limiting element is always between the transformer that supplies the feeder and the first node on the feeder where the load splits between two or more branches.	
Summer Rating (MVA)	Summer normal rating of the feeder's limiting element in MVA. The feeder's limiting element is always between the transformer that supplies the feeder and the first node on the feeder where the load splits between two or more branches.	Operating Voltage (kV) * Summer Rating (Amps) * $\sqrt{3}$
Potential Available Load Capacity (MVA)	Maximum additional load, in MVA, that can be connected to the feeder without causing the feeder's	Summer Rating (MVA) - 2023 Peak (MVA)

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Misc.

Data Field	Description	Calculation
	projected 2023 peak load to exceed the feeder's summer normal rating.	
Peak Amps 2022	Actual 2022 peak load of the feeder in amps	
2022 Peak (MVA)	Actual 2022 peak load of the feeder in MVA	Peak Amps 2022 * Operating Voltage (kV) * $\sqrt{3}$
Peak Amps 2023	Projected 2023 peak load of the feeder in amps	Peak Amps 2022 * 2023 Growth Rate * 2023 Weather Adjustment
2023 Peak (MVA)	Projected 2023 peak load of the feeder in MVA	2022 Peak (MVA) * 2023 Growth Rate * 2023 Weather Adjustment
2023 Peak (%)	Projected 2023 peak loading of the feeder as a percent of the feeder's summer normal rating	Peak Amps 2023 / Summer Rating (Amps) * 100%
2024 Forecast (MVA)	Projected 2024 peak load of the feeder in MVA	2023 Peak (MVA) * 2024 Growth Rate
2025 Forecast (MVA)	Projected 2025 peak load of the feeder in MVA	2024 Peak (MVA) * 2025 Growth Rate
2026 Forecast (MVA)	Projected 2026 peak load of the feeder in MVA	2025 Peak (MVA) * 2026 Growth Rate
2027 Forecast (MVA)	Projected 2027 peak load of the feeder in MVA	2026 Peak (MVA) * 2027 Growth Rate
2028 Forecast (MVA)	Projected 2028 peak load of the feeder in MVA	2027 Peak (MVA) * 2028 Growth Rate
2029 Forecast (MVA)	Projected 2029 peak load of the feeder in MVA	2028 Peak (MVA) * 2029 Growth Rate
2030 Forecast (MVA)	projected 2030 peak load of the feeder in MVA	2029 Peak (MVA) * 2030 Growth Rate
2031 Forecast (MVA)	projected 2031 peak load of the feeder in MVA	2030 Peak (MVA) * 2031 Growth Rate
2032 Forecast (MVA)	projected 2032 peak load of the feeder in MVA	2031 Peak (MVA) * 2032 Growth Rate

This compiled annual capacity review data is input directly into the Company's heat map pop-up data. The Company's heat map color-coding varies with the 2023 Peak (%) data field as described in the following table:

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Misc.

2023 Peak (%)	Heat Map Color
0% - 50%	
50% - 70%	
70% - 80%	
80% - 90 %	
90% - 95%	
95% - 100%	
100% and above	

PUC 1-47
Misc.

Request:

Referencing Bates page 69, when will each of the area studies be refreshed?

Response:

The refresh date of each area study has not been determined at this time. Rhode Island Energy suggests that specific area studies should not be refreshed on a set schedule, but that the Company's subject matter experts should determine when it is appropriate to refresh any study. This will ensure that resources are used efficiently, concepts like grid modernization and integrated system planning are sufficiently incorporated into future study efforts, and major work and reconfigurations can be completed.

Prepared by or under the supervision: Ryan Constable

PUC 1-48
Misc.

Request:

On Bates page 84, the Company states that "[t]here are some projects in the long-term forecast that are in process of having the total project cost estimates revised and the long-term forecast will be updated once those estimates are complete."

(a) When does the Company expect the revisions to be completed?

(b) (Revised as a result of the January 20, 2023 open meeting decision): Is there any spending in the FY 2024 plan (April 1, 2023 through March 31, 2024) that would be impacted? If so, please identify.

Response:

(a) The Company expects revisions to be completed in the spring of 2023.

(b) Currently, the only project within the long-term forecast for which the Company is revisiting costs is New Lafayette Substation. This project is delayed because of transmission outage coordination issues, and construction will now begin in calendar year 2025. The Company is confident in the ability to spend the budget provided in the FY 2024 Electric ISR Plan but is in the process of revisiting future year spend, taking into consideration inflation and increased material costs.

Prepared by or under the supervision: Nicole Begnal

PUC 1-49

Misc.

Request:

Referencing Bates page 91, is the line "reserves - DF" a new category within Damage/Failure? If not, where was it shown previously? If it is new, please explain the need for a new reserve.

Response:

"Reserves - DF" is not a new category within Damage/Failure. It can be seen in Docket 5209 Chart 15 - Proposed FY2023 Capital Spending – Damage/Failure on Bates page 60.

"Reserves - DF" falls under Damage/Failure in Attachment 1 and Attachment 3. The spend can also be seen in Attachment 2 on Bates page 111 for Project # C051608 and C046986.

PUC 1-50
Misc.

Request:

Referencing Bates page 91, is the line "Storms and Weather Events" a new category within Damage/Failure? If not, where was it shown previously?

Response:

"Storms and Weather Events" is not a new category within Damage/Failure. It can be seen in Docket 5209 Chart 15 - Proposed FY2023 Capital Spending – Damage/Failure on Bates page 60.

"Storms and Weather Events" falls under "Major Storms" in Attachment 1 and "Storms" Attachment 3. The spend can also be seen in Attachment 2 on Bates page 111 for Project # C022433.

Prepared by or under the supervision: Nicole Begnal

PUC 1-51
Customer Payments – DG Interconnection Follow-Up

Request:

As part of its Open Meeting decision on March 29, 2022, The Narragansett Electric Company was required to include a review of all DG projects for which the customer contribution did not cover the full cost of the project; the reasons why; and the impact on rate base and the associated revenue requirement. The report was to be filed no later than August 1, 2022 with the Reconciliation of the Electric ISR filing with all necessary adjustments to any ISR revenue requirement/reconciliation explained and highlighted. An adjustment was included in the FY 2022 Electric ISR Reconciliation Filing and a report was to be forthcoming by October 1, 2022, but no report was filed (https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-08/5098-RIE-Electric-ISR-FY22-Reconciliation_8-1-22.pdf) Easterly Test. at 6. In the Company's FY 2023 Q2 report, the Company has indicated that it does not intend to file the analysis until as late as March 31, 2023.

(a) Please explain the delay in the analysis.
(b) Please indicate the number of projects under review.
(c) Please indicate the total amount that was included in rate base for the projects under review (net of the adjustment already made in the FY 2022 reconciliation filing).

Response:

(a) The delay is due to many unexpected challenges in compiling the information to understand the history of these projects. The Company continues to seek documentation that would provide a clear understanding of the drivers of the differences between actuals and estimates. It has taken longer than expected to contact the personnel who directly worked on the projects under review. In parallel the team is using its technical knowledge to identify drivers.

It is anticipated that the results of this review will incorporate available data and, because of the factors listed above, technical assumptions. By the end of March, the team will determine whether the variances between customer contributions and costs are due to system modifications, misapplied contributions or actuals being higher than estimated. The Rhode Island Energy team now working on distributed generation (DG) projects is part of a smaller, local organization, and communications are improving when scope and spend are changing. There will also be a documented end-to-end process to ensure this information is captured going forward.

Prepared by or under the supervision: Nicole Begnal

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Customer Payments – DG Interconnection Follow-Up

(b) The Company is reviewing 17 projects. Two additional projects were reviewed in conjunction with the Company response to Docket 5209 PUC 2-7.

(c) Plant additions of $4.5 million have been included in rate base related to the projects under review. This amount is net of the adjustment made in the FY 2022 reconciliation filing.

Prepared by or under the supervision: Nicole Begnal