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

Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan

Discovery

Responses to Division Data Requests
Sets 1 through 5

Book 3 of 3

December 23, 2024

Docket No. 24-54-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

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Rhode Island Energy™
a PPL company

December 20, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 1 (Complete Set)

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's complete set of responses to the Division's First Set of Data requests in the above-referenced matter ("Division Set 1"). This transmittal contains the Company's responses to Division 1-30 and 1-58 and completes all responses to Division Set 1 in this matter.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: John Bell, Division
Greg Booth, Division
Al Contente, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.

Division 1-1

Request:

In executable format, please provide the underlying reliability data for:

a. Attachment 4-Chart 1
b. Attachment 4-Chart 2
c. Attachment 4-Chart 5
d. Attachment 4-Chart 6

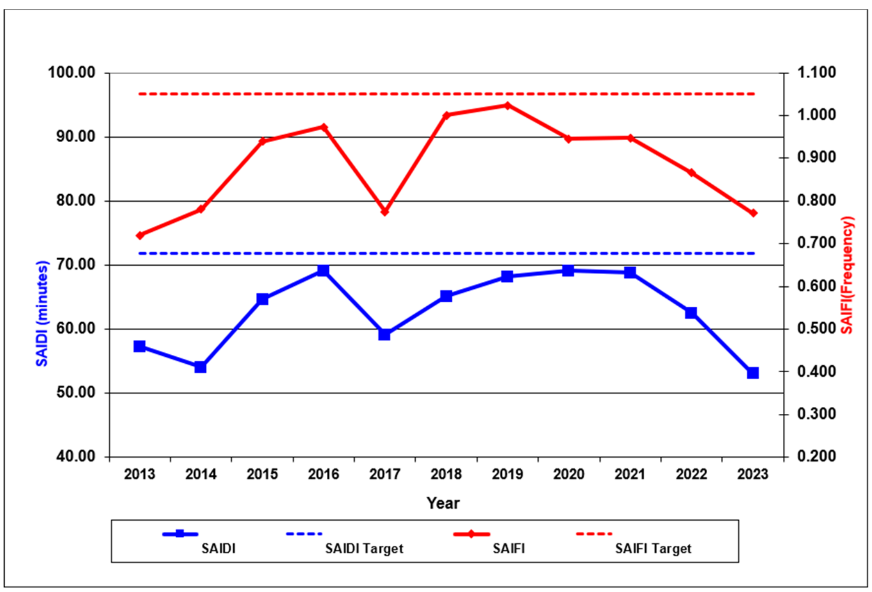
Response:

The following attachments contain the charts in executable format:

a. Attachment DIV 1-1-1 - Attachment 4-Chart 1
b. Attachment DIV 1-1-2 - Attachment 4-Chart 2
c. Attachment DIV 1-1-3 - Attachment 4-Chart 5
d. Attachment DIV 1-1-4 - Attachment 4-Chart 6

Attachment 4 – Chart 5 in the FY26 ISR Plan Proposal has an error in the SAIDI data. The corrected chart is shown below.

Attachment 4 – Chart 5-Corrected
RI Reliability Performance CY 2013 – CY 2023
Regulatory Criteria (Excluding Major Event Days)



Prepared by or under the supervision of: Ryan Constable

Division 1-2

Request:

Provide the Company's most recent load projections for feeders and substation transformers in executable format. Please expand the file to include actual load for each feeder and transformer from 2015 to 2023.

Response:

Please see Attachment DIV 1-2 containing the Company's most recent load projections for feeders and substation transformers in executable format. The file includes actual load for each feeder and transformer from 2015 to 2023.

Prepared by or under the supervision of: Ryan Constable

Attachment DIV 1-2

As requested by the Division, the Company is providing the Excel file of Attachment DIV 1-2.

The Excel spreadsheet is too large to create a legible PDF version.

Prepared by or under the supervision of: Ryan Constable

Division 1-3

Request:

In executable format for the years 2012, 2018, 2024 and 2030 (projected assuming the Long-Range Plan is implemented as proposed), please provide:

a. Number of distribution substations,
b. Number of distribution substation transformers in service,
c. Distribution transformer total capacity (normal and emergency),
d. Number of distribution feeders,
e. Distribution feeder total capacity,
f. System peak load, and
g. EE MW reductions

Response:

Please find, in executable format for the years 2012, 2018, 2024 and 2030 (projected assuming the Long-Range Plan is implemented as proposed), the following:

a. Number of distribution substations,
b. Number of distribution substation transformers in service,
c. Distribution transformer total capacity (normal and emergency),
d. Number of distribution feeders,
e. Distribution feeder total capacity,
f. System peak load, and
g. EE MW reductions

The system peak load for 2024 is a forecasted number because the 2025 forecast has not been finalized.

Prepared by or under the supervision of: Ryan Constable

		(a)	(b)	(c1)	(c2)	(d)	(e)	(f)	(g)
	Year	# of Distribution Substations	# of Distribution Transformers in Service	Distribution Transformer Capacity (Normal)	Distribution Transformer Capacity (Emergency)	# of Distribution Feeders	Distribution Feeder Total Capacity	System Peak Load MW	EE MW Reductions
(1)	2012	100	203	4348.1	4839.1	397	2874.0	1892	113
(2)	2018	99	207	4704.0	5256.0	398	3058.7	1847	281
(3)	2024	93	190	5295.8	5687.4	377	3288.5	1819	387
(4)	2030	78	160	5480.1	5908.6	336	3399.6	1799	455

Division 1-4
Plan Development

Request:

The Company's approved ISR Plan capital budgets, excluding AMF, were $112 million in FY 2024 and $132 million in FY 2025. The Company is proposing a budget of $197 million in FY 2026. Discuss how each of the Company's objectives in developing the work plan (priorities, budget and resources) have changed in the past three years to drive significant increases in spend. How is the Company able to support significant workload increases with its current resource levels?

Response:

The Company's objectives in developing the work plan have not changed in the past three years. The Company continues to identify and prioritize investments that are necessary to provide safe and reliable electric distribution service for all its customers in the short term and the long term.

The proposed FY 2026 budget is higher than the past two approved ISR Plan capital budgets; however, it is not significantly higher than what was initially proposed in those plans. The Company's initial filing to the Division for the FY 2025 ISR Plan was $179.1 million. Similarly, the FY 2024 12-month proposed budget filed with the Commission was $176.3 million. Thus, the Company's objectives in developing its workplan have remained constant over the prior three years.

As discussed over the last several years, upon completion of the 11 area studies, the Company would include projects identified in the area studies in its long range plan and ISR Plan filings to address the backlog of projects related to assets with deteriorated condition, reliability and loading concerns. The majority of the area study projects were initiated in either FY 2024 or FY 2025 and are multi-year projects. The Company is completing design and procurement on these projects and is progressing them into construction in FY 2026, which is, in part, a driver of the increase in spend over the prior two fiscal year plans.

The Company resources work in a manner that is flexible and efficient, which allows the Company to scale up (or down) its workload. The Company is confident in its ability to execute on the proposed workplan and has incorporated long lead times into its execution schedules.

Prepared by or under the supervision of: Nicole Gooding

Division 1-5
Plan Development

Request:

Regarding Grid Modernization Plan Analysis, the Company states that "In line with this finding, the Company has considered and proposed, where appropriate, grid modernization solutions to system issues throughout this ISR Plan." (Bates page 15). Please indicate each area of the FY 2026 ISR Plan where a grid modernization solution is proposed. Describe the system issue, why the grid modernization solution is appropriate, and proposed spend.

Response:

Certain aspects of the grid modernization strategy have been incorporated into the Company's standard equipment, such as advanced reclosers and capacitors. Regardless of whether grid modernization equipment is included in the scope, all investments in the FY 2026 ISR Plan are justified for specific short-term and long-term needs. However, the Company discussed the following investments specifically in its grid modernization plan, and each of these investments is a demonstration of how the Company is implementing this strategy appropriately to address system needs for the provision of safe and reliable electric distribution service in the short-term and the long-term:

- **VVO/CVR Smart Capacitor and Regulators Program**
  - System Issue – The VVO/CVR program optimizes voltage performance to enable lower energy usage and lower customer bills.
  - Grid Modernization Strategy – Advanced capacitor and regulator controls aligned with the grid modernization strategy will be installed under this program.
  - Proposed FY 2026 Spend – $2.5 million.
- **Distribution Automation Recloser Program**
  - System Issue – This program uses advanced reclosers to address circuit specific reliability issues focusing on the circuits or portions of the electric system performing below acceptable levels.
  - Grid Modernization Strategy – To address the reliability issue, the Company would use its standard advanced recloser. These advanced reclosers are aligned with the grid modernization strategy.
  - Proposed FY 2026 Spend – $6.68 million.

Division 1-5, page 2
Plan Development

- **Electromechanical Relay Upgrades Program**
  - System Issue – The existing electromechanical relays have limited coordination capabilities, no remote access to information, and no fault data capture. The limited capabilities contribute to reliability issues and additional time and cost for fault troubleshooting.
  - Grid Modernization Strategy – The upgraded equipment will provide fault data capture, remote access, and provide greater flexibility for coordination with other devices aligned with the grid modernization strategy, which reduces fault troubleshooting costs and addresses reliability issues.
  - Proposed FY 2026 Spend – $1.007 million.
- **Fiber Network project**
  - System Issue – The existing station communication system is costly and relies on third party circuits with uncertain allocated bandwidth and prioritization. Any interruptions in this communication result in a lack of situational awareness and require immediate staffing of any bulk power locations. During major events with widespread outages, third party telecommunications circuits may also experience outages.
  - Grid Modernization Strategy – The Company is proposing to install fiber optic cable to provide secure data flow addressing the communication risk as aligned with the grid modernization plan.
  - Proposed FY 2026 Spend – $500,000.

Division 1-6

Plan Development

Request:

What projects will be subject to Docket 4600 Analysis, expected to be filed in December 2024?

Response:

The Company plans to complete Docket 4600 Analysis for the FY 2026 Distribution Automation Recloser Program, the Chase Hill 155F8 Reconductoring project, and the Chase Hill Station Expansion project.

The Company will seek further guidance if Docket 4600 Analysis is necessary for asset condition projects such as Gate II Equipment Replacement, Hospital #146 Equipment Replacement, and Kingston Equipment Replacement.

Prepared by or under the supervision of: Ryan Constable

Division 1-7
Plan Development

Request:

The Company states that "The spending for investments is anticipated to be higher in the near-term because of the backlog of system issues identified through Area Studies. Once the backlog is complete, the Company anticipates that the level of investment will be a smaller proportion of the total budget." (Bates 19) The Company customarily maintains a backlog of discretionary work and paces that work over a longer term to maintain a reasonable budget and effectively manage resources. Why is the Company proposing significant and discretionary Area Study work over a shorter period of time rather than a more moderate schedule? How has the Company accounted for customer affordability in its proposal?

Response:

The Company has paced the Area Study work as moderately as is reasonable to also continue to provide safe, affordable, and reliable electric distribution service in the short- and long-term. The Company has a backlog of system issues that built up pending the completion of Area Studies, and the work to address those issues has been delayed even further due to supply chain constraints and other unavoidable project delays.

For example, the East Bay Area Study originally had the East Providence Substation project completing in Fiscal Year ("FY") 2023. Because of permitting delays and increased lead times on long lead materials, this project is now scheduled to be completed in FY 2027. Although the delays have not caused imminent safety issues and reliability disruptions overall, the delay on these projects already has created a greater level of risk to safety and reliability for the Company's customers that the Company seeks to address and mitigate as expeditiously as possible. Completing these projects in the short term will reduce the risk that a damage/failure event occurs before the projects are complete, which would likely result in higher costs. As such, the Company accounts for customer affordability in its proposal because completing these projects in the short term reduces the risk of significant cost increases that are more likely to result if the projects are completed over a longer time period.

Prepared by or under the supervision of: Nicole Gooding

Division 1-8
Customer Request/Public Requirements

Request:

Generally, explain how RIE derived the budgets for the seven areas of spend in Customer Request/Public Requirement. Compare/contrast the methods of budget development to previous years, highlighting any differences.

Response:

Descriptions of the development of budgets for the Customer Request/Public Requirement areas of spend with comparisons to previous years are shown below.

New Business – Commercial

This category is made up of (a) a blanket project, (b) specific projects for known work greater than $500,000, and (c) a reserve for emerging projects that cannot be identified at the time of filing.

(a) The blanket project budget was developed using historical data from FY 2019 through May 2024 to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. An inflationary increase was applied, and the budget proposal was established.

A similar process was followed in previous years, except that individual inflation rates were used to increase the rolling twelve-month spending totals for different cost types (labor and benefits, transportation, materials, consultants and contractors, etc.).

(b) Budgets were established for two specific projects that are in progress and have forecasted spending into FY 2026 and beyond.

(c) The reserve project budget was developed using blanket project and specific project historical data to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. An inflationary increase was applied. To avoid duplication, an amount equal to the blanket project budget proposal developed in part (a) was removed. The budget proposal was established.

Customer Request/Public Requirements

A similar process was followed in most of the previous years, except that the blanket project spending data was not included in the development of the reserve budget. It is necessary to include all New Business-Commercial spending in the development of the reserves due to the change in the blanket level individual work request change from $100,000 to $500,000.

New Business – Residential

This category is made up of (a) a blanket project and (b) reserve for emerging projects that cannot be identified at the time of filing.

(a) The blanket project budget was developed using historical data from FY 2019 through May 2024 to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. An inflationary increase was applied, and the budget proposal was established.

A similar process was followed in previous years, except that individual inflation rates were used to increase the rolling twelve-month spending totals for different cost types (labor and benefits, transportation, materials, consultants and contractors, etc.).

(b) The reserve project budget was developed using blanket project and specific project historical data to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. An inflationary increase was applied. To avoid duplication, an amount equal to the blanket project budget proposal developed in part (a) was removed. The budget proposal was established.

A similar process was followed in most of the previous years, except that the blanket project spending data was not included in the development of the reserve budget. It is necessary to include all New Business-Residential spending in the development of the reserves due to the change in the blanket level individual work request change from $100,000 to $500,000.

No specific projects in progress that will have forecasted spending into FY 2026 and beyond were identified during the review or conversations with the Operations or Customer teams.

Division 1-8, page 3

Customer Request/Public Requirements

Public Requirements

This category is made up of (a) a blanket project, (b) specific projects for known work greater than $500,000, and (c) a project for the billing of joint owned pole replacements.

(a) The blanket project budget was developed using historical data from FY 2019 through May 2024 to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. Adjustments were made to reflect the reduced level of RIDOT activity and reduced reimbursement percentage (50% as of June 2022, instead of 100%) and an inflationary increase was applied. The budget proposal was established.

A similar process was followed in previous years, except that individual inflation rates were used to increase the rolling twelve-month spending totals for different cost types (labor and benefits, transportation, materials, consultants and contractors, etc.).

(b) The reserve project budget was developed using blanket project and specific project historical data to create rolling twelve-month spending totals. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. Adjustments were made to reflect reduced reimbursement percentage (50% as of June 2022, instead of 100%) and an inflationary increase was applied. To avoid duplication, an amount equal to the blanket project budget proposal developed in part (a) was removed. The budget proposal was established.

A similar process was followed in most of the previous years, except that the blanket project spending data was not included in the development of the reserve budget. It is necessary to include all Public Requirements spending in the development of the reserves due to the change in the blanket level individual work request change from $100,000 to $500,000.

(c) The budget for the project that contains the billing for joint-owned pole replacements is a reduction to the overall ISR budget. The FY 2026 proposed budget of $(2.4) million, which has increased from $(1.8) million in previous years, is based on a forecasted higher level of reimbursement. A similar process was followed in most of the previous years. The capital spending associated with joint-owned pole replacements is recorded in several ISR projects, including Damage/Failure Blanket, Asset Replacement Blanket, Reliability Blanket, and in specific projects.

Division 1-8, page 4

Customer Request/Public Requirements

Transformers & Related Equipment

For the FY 2026 Plan, the Company proposed a budget equal to the forecasted spending for transformers and related equipment included in the FY 2025 Q1 and Q2 ISR Reports. For more information on this category, please see the Company's response to Division 1-9. A similar process was followed in most of the previous years.

Meters and Meter Work

This category is made up of (a) AMR meter purchases and (b) a blanket project for AMR meter installations and changes, which is based off the number of meters to be purchased and expected labor costs associated with installations. A similar process was followed in most of the previous years. The FY 2026 proposed budgets represent a reduced level of spending associated with AMR meters as the AMF program accelerates. The budgets represent the continued level of spending associated with the purchase and installation of AMR meters, which will gradually decrease after FY 2026, but is not expected to be entirely eliminated.

Distributed Generation

This category of spending is made up of (a) a placeholder for distributed generation project activity and (b) two system improvement projects.

(a) The budget of $1.0 million for distributed generation projects has been used for several years to represent the potential lag in timing between actual project spending and CIAC offsets that reduce the capital spending. Plant additions are not forecasted on this placeholder, therefore there is no effect on the proposed revenue requirement.

(b) Forecasted spending for the two specific projects were forecasted by the Company based on the specific project requirements. The Company has not identified any system improvements in an ISR Plan filing in prior years.

Other

This category is made up of (a) a blanket project for third party attachment work, (b) a blanket project for land and land rights, and (c) a blanket project for outdoor lighting. The proposed budgets were developed by reviewing historical data from FY 2019 through May 2024. One-time items and trends were identified. Input from local Operations and Customer teams was incorporated into the analysis prior to establishing the budget. This approach is consistent with the development of budgets for these projects in prior years.

Prepared by or under the supervision of: Nicole Gooding

Division 1-9

Customer Request/Public Requirements

Request:

Provide a breakdown of the inputs or analysis used to derive the $12 million budget for Transformers & Related Equipment, including proposed quantities and unit prices.

Response:

For the FY 2026 Plan, the Company proposed a budget equal to the forecasted spending for transformers and related equipment included in the FY 2025 Q1 and Q2 ISR Reports. Both availability and unit pricing of transformers and related equipment continue to be in flux due to supply chain issues. It is difficult to forecast with any level of accuracy at a detailed level (i.e., units available for purchase and unit pricing for specific units) because unit availability, delivery schedules, and unit prices are uncertain. The Company has seen delays as long as three years from original delivery dates. The Company is purchasing needed transformers as they become available from multiple suppliers. Inventories of line transformers are leveling, but certain units, such as three-phase pad mount transformers, remain in limited supply. Field teams are installing transformers available, making safe substitutions as required. If additional substantial information becomes available before December's filing with the Commission, the Company may update its proposal. At this time, such information is not available.

Prepared by or under the supervision of: Nicole Gooding

Division 1-10
Customer Request/Public Requirements

Request:

Regarding each of the two system improvement projects included on the Distribution Generation line of Chart 5 (Bates page 27), please provide:

a. A detailed description of the project including scope and estimated cost,
b. Why the project is required, and the specific system need that warrants the improvement,
c. Whether the system improvement would be installed absent the DG interconnection, and if so, when,
d. Name and description of the DG projects associated with the system improvement,
e. DG interconnection agreements or other documentation delineating project and cost responsibilities for both system modifications and system improvements, and
f. The factors considered by the Company in making a determination to advance the system improvement.

Response:

The Company will be removing the 85T2 Neutral Project from the ISR Plan. Please see below for a response for the 85T3 Neutral Project.

85T3 Neutral Project:

a. The project scope includes installing a neutral conductor approximately 9,340 feet from Pole # 9135 in the right-of-way off Alton Bradford Road through the right-of-way to Pole # 96 Ashaway Road. The Company estimated this project at $1.3 million. The Company is revising that estimate and will provide an update as soon as it is available.

b. This project is needed to provide effective grounding. The 85T3 circuit will be used to serve customers directly through an automated transfer scheme with the 85T1. Effective grounding is a requirement for service to the typical Rhode Island Energy customer. The project needs to be completed prior to the transfer of customers to the 34.5 kV system, which would occur during FY 2027.

c. The Company would install the project absent the DG interconnection per the current budget. See the response to subpart f. for additional explanation regarding the relationship of this project to the DG interconnection.

Division 1-10, page 2
Customer Request/Public Requirements

d. There are three DG sites that were studied assuming the system was effectively grounded:
    a. Frontier Road, Hopkinton, 9.5MW
    b. Main Street, Hopkinton, 5.6MW
    c. Nooseneck Hill Road, Hopkinton, 5.0MW

e. The DG interconnection documents have not been finalized. However, the DG interconnection agreements will include the following statement: "Company Cost Responsibility: Extend ~9,340' of 1/0 AL neutral conductor from Pole #9135 ROW, Hopkinton, RI to Pole #96 ROW, Hopkinton, RI."

f. The issue was identified in the South County West Area Study. Approximately 6 miles of neutral conductor will be required for a 34.5 kV extension to solve a reliability problem. The reliability-based system need is the factor the Company considered in deciding to advance the project; however, subsequent to this decision, the Company received DG interconnection applications for projects planned in the same geographical area as the reliability-based project. Because this circuit must be effectively grounded to serve customers and the DG projects have specific protection and fault current requirements on an effectively grounded system that differ from the requirements on an ineffectively grounded system, the Company conducted the interconnection studies for these DG projects based on having an effectively grounded system. The Company categorized the work under the non-discretionary distributed generation spending rationale for two reasons. First, the Company considers this work non-discretionary and other non-discretionary categories were less applicable. Second, although the work did not result from a DG impact study, completing the neutral project to have an effectively grounded system to which the projects would interconnect was the basis for multiple interconnection studies. As a result, the Company determined that the distributed generation spending rationale was the most applicable category for this work.

Division 1-11
Damage/Failure

Request:

In executable format, please update the Nasonville costs provided in response to FY 2024 ISR Plan Reconciliation, Attachment DIV 1-10 (corrected) shown below:

	Capital Costs (000s)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		FY 2023 Actuals	FY 2024 Actuals	FY 2025 Forecast	FY 2026 Forecast	FY 2027 Forecast	FY 2028 Forecast	FY 2029 Forecast	FY 2030 Forecast	Total
1	Damage/Failure - initial restoration due to metalclad switchgear failure	488								**488**
2	Damage/Failure - costs to prepare and improve the site for replacement equipment	213	4,198	2,584	981					**7,976**
3	**Total Damage/Failure**	**701**	**4,198**	**2,584**	**981**					**8,464**
4	System Capacity & Performance - Distribution Substation for Expansion		2,558	4,500	6,420	1,307				**14,785**
5	System Capacity & Performance - Distribution Line for Expansion		28	106	123	36				**293**
6	**Total System Capacity & Performance**	**-**	**2,586**	**4,606**	**6,543**	**1,343**				**15,078**
7	Area Study Estimate - Distribution Substation Expansion		875	750	1,170	2,340	4,680	2,340	1,170	**13,325**
8	Area Study Estimate - Distribution Line Expansion		37	54	107	54	27			**279**
9	**Total Area Study Estimate**		**912**	**804**	**1,277**	**2,394**	**4,707**	**2,340**	**1,170**	**13,604**

Response:

Please see the table below and Attachment DIV 1-11 for the corresponding Excel file.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(i)
	Capital Spending ($000s)	FY 2023 Actuals	FY 2024 Actuals	FY 2025 Forecast - Q2 Report	FY 2026 Forecast	FY 2027 Forecast	FY 2028 Forecast	FY 2029 Forecast	FY 2030 Forecast	**Total**
1	Damage/Failure									
2	Initial restoration due to metalclad switchgear failure	$488	-	-	-	-	-	-	-	**$488**
3	Costs to prepare and improve the site for replacement equipment	213	4,198	3,226	340	-	-	-	-	**7,977**
4	Total Damage/Failure	$701	$4,198	$3,226	$340	-	-	-	-	**$8,465**
5	System Capacity & Performance									
6	Distribution Substation for Expansion	-	$2,558	$4,515	$6,420	$1,307	-	-	-	**$14,800**
7	Distribution Line for Expansion	-	28	104	111	-	-	-	-	**243**
8	Total System Capacity & Performance	$0	$2,586	$4,619	$6,531	$1,307	-	-	-	**$15,043**
9	Area Study Estimate									
10	Distribution Substation Expansion	-	$875	$750	$1,170	$2,340	$4,680	$2,340	$1,170	**$13,325**
11	Distribution Line Expansion	-	37	54	107	54	27	-	-	**279**
12	Total Area Study Estimate	-	$912	$804	$1,277	$2,394	$4,707	$2,340	$1,170	**$13,604**

Prepared by or under the supervision of: Daniel Glenning

Division 1-12
Damage/Failure

Request:

Provide an explanation of how Nasonville work is categorized as non-discretionary Damage/Failure versus discretionary station rebuild. If the initial station restoration due to the metalclad failure has been completed, why is the Company continuing to incur Damage/Failure expenses?

Response:

The scope of the Nasonville project consists of both non-discretionary Damage/Failure and discretionary work. The scope of work associated with the August 2022 metal clad switchgear damage due to a fault is covered under the Damage/Failure category. The Company is replacing the failed switchgear with an open-air straight bus (bus #1) that will include a main bus, four feeder breakers and associated switches. The existing transmission line and existing transformer will initially supply the new bus #1. This phase of work, which is necessary to install primary electrical equipment to fully commission bus #1, is associated with Damage/Failure work and is scheduled to be completed by the end of FY 2025 with closeout activities in FY 2026.

The distribution scope of the discretionary work for the Nasonville Expansion project will expand the substation with one new transformer, seven new breakers (tie breakers and bus #2 breakers), and two new capacitor banks as recommended in the Northwest Rhode Island Area Study. The substation expansion will be an open air design, with the new transformer due to be delivered within the next month or two.

Prepared by or under the supervision of: Daniel Glenning

Division 1-13
Damage/Failure

Request:

What are the drivers of costs to prepare and improve the site for replacement equipment in Damage/Failure? Are these investments required to replace the failed metalclad switchgear or to prepare the site for a newly configured open air design?

Response:

One of the main cost drivers faced with the Nasonville Damage/Failure was the configuration of the cables in the substation. Once the mobile switchgear was delivered, cables were run through the substation yard to keep the substation energized. The arrangement of the cables and mobile switchgear prevented replacement of the metalclad switchgear in its current location. To replace the failed metalclad switchgear, the Company had to expand the substation fence and perform below grade work activities, which included foundations, conduits and manholes. A second cost driver was the construction of a retaining wall because of the stability of a hill adjacent to the substation.

These costs were associated with the Damage/Failure project. As described in the Company's response to Division 1-11 in Docket No. 22-53-EL, the decision to change from a metalclad to an open-air design was due to material availability. This change allowed the Damage/Failure project to be completed one year sooner and minimize the mobile switchgear recall risk.

Prepared by or under the supervision of: Daniel Glenning

Division 1-14
Damage/Failure

Request:

What is the planned work for Nasonville in FY 2026, comprising a proposed budget of $1 million in Damage/Failure?

Response:

As reflected in the FY 2025 Second Quarter Report, the forecast for the Damage/Failure work has increased in FY 2025. This has reduced the forecast in FY 2026 to $50,000 solely for closeout activities for the Damage/Failure project.

Prepared by or under the supervision of: Daniel Glenning

Division 1-15
Asset Condition

Request:

For each Asset Condition substation project, provide the amount and duration of unserved load in event of loss of supply or a transformer based on current and projected loads.

Response:

The amount and duration of unserved load in event of loss of supply or a transformer based on current and projected loads is shown in Tables DIV 1-15-1 and DIV 1-15-2, respectively, below for each Asset Condition substation project. For the evaluation for projected loads, the Company used 2030 values.

Unserved load is considered the load remaining interrupted after the contingency and after the system has been reconfigured. The switching time, which can be a number of hours, and the unserved load during this switching time are not included in the values. The duration of the unserved load is presented in hours and is the duration of the repair or the time necessary to mobilize and install spare or mobile equipment.

The Company does not consider an unserved load evaluation to be an appropriate basis upon which to determine the timing for when it should perform asset condition work. Because these substations contain assets with complicated contingencies that an unserved load analysis does not identify, the Company also has included the load that would remain in an abnormal configuration and the duration of that abnormal configuration, which presents associated reliability, voltage, and further contingency exposure that is not captured by solely looking at unserved load.

Division 1-15, page 2
Asset Condition

Table DIV 1-15-1 – Unserved Load – Current Loads

Asset Condition Project	Unserved Load (MW)	Duration of Unserved Load (Hours)	Load in Abnormal Configuration (MWs)	Duration of Abnormal Configuration
Providence Long-term Study Projects	0.0	0	7.7	2 to 3 years
Tiverton Substation	0.0	0	31.2	8 hours
Gate II Equipment Replacement	0.0	0	33.8	2 to 3 years
Phillipsdale Substation D Line	7.0	24	12.5	2 to 3 years
Crossman St Substation D Line	0.9	24	2.9	2 to 3 years
Central Falls Substation D Line	0.0	0	3.0	2 to 3 years
Division St. Substation T1 T2 Replacement	0.0	0	14.3	2 to 3 years
Anthony Substation Equipment Replacement	0.0	0	4.3	2 to 3 years
Natick Substation Equipment Replacement	0.0	0	6.7	2 to 3 years
Warwick Mall Substation Equipment Replacement	0.0	0	2.3	2 to 3 years
Coventry Substation Relocation	0.0	0	8.1	2 to 3 years
Hope Substation Equipment Replacement	0.0	0	4.6	2 to 3 years
Dexter 36 Equipment Replacement	0.0	0	20.2	2 to 3 years
West Greenville Airbreak Replacements	0.0	0	5.9	8 hours
Centredale Substation D Sub	3.1	8	0.0	0

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Asset Condition

Table DIV 1-15-2 – Unserved Load – Projected Loads

Asset Condition Project	Unserved Load (MW)	Duration of Unserved Load (Hours)	Load in Abnormal Configuration (MWs)	Duration of Abnormal Configuration
Providence Long-term Study Projects	0.0	0	7.7	2 to 3 years
Tiverton Substation	1.5	8	33.4	8 hours
Gate II Equipment Replacement	0.0	0	35.6	2 to 3 years
Phillipsdale Substation D Line	7.1	24	12.6	2 to 3 years
Crossman St Substation D Line	2.9	24	2.9	2 to 3 years
Central Falls Substation D Line	3.4	24	5.0	2 to 3 years
Division St. Substation T1 T2 Replacement	0.0	0	17.2	2 to 3 years
Anthony Substation Equipment Replacement	0.0	0	4.9	2 to 3 years
Natick Substation Equipment Replacement	0.0	0	6.8	2 to 3 years
Warwick Mall Substation Equipment Replacement	0.0	0	2.6	2 to 3 years
Coventry Substation Relocation	0.3	0	8.9	2 to 3 years
Hope Substation Equipment Replacement	0.0	0	3.4	2 to 3 years
Dexter 36 Equipment Replacement	1.0	24	23.7	2 to 3 years
West Greenville Airbreak Replacements	0.0	0	6.1	8 hours
Centredale Substation D Sub	3.1	8	0.0	0

Division 1-16
Asset Condition

Request:

The Company proposes advancing the Auburn substation between FY 2027 and FY 2030. What is the status of permitting and schedule of the 115kV system extension needed to serve the proposed Auburn substation?

Response:

Due to the project need date, the transmission line portion of the Auburn Substation has recently been initiated and is undergoing a permitting assessment. Once the assessment is completed, the Company will prepare a detailed schedule, including permitting timeframes and material lead times.

Prepared by or under the supervision of: Daniel Glenning

Division 1-17
Asset Condition

Request:

Please provide:

a. Annual historical and proposed spend for Admiral Street. Separately indicate substation and distribution work. Include a general description of work performed or planned each year.

b. The original Admiral Street substation and distribution cost estimates for the preferred solution derived in the Area Study

c. Annual proposed spend for Auburn derived in the Area Study. Separately indicate substation and distribution work. Include a general description of work planned each year, indicating how the project will be sequenced with Admiral Street.

Response:

a. Please see the tables below for annual historical and proposed spend for both distribution line ("D-Line") and substation work for Admiral Street. As a note, the Company has referred to the Admiral Street Project as Providence Study Phase 1A and Phase 1B in previous ISR reporting. The Area Study recommendation is known as Admiral Street, but the work was split into phases for sequencing.

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Asset Condition

Distribution Line

	(a)	(b)	(c)
	Fiscal Year	Actual (or Proposed) Capital Spend (000s)	Activity (or Planned Activity)
1	2020	633	Planning & Engineering
2	2021	2,099	Engineering, permitting and long lead procurement
3	2022	5,211	Engineering, long lead procurement and D-Line construction
4	2023	6,136	Engineering, procurement and D-Line construction
5	2024	11,444	Engineering, long lead procurement, and D-Line civil construction of manholes & duct line.
6	2025	(130)	Credit to project due to system accounting error and D-line civil construction of manholes & duct line.
7	2026	9,728	Underground cable procurement and installation

Prepared by or under the supervision of: Ryan Constable

Asset Condition

Substation

	(a)	(b)	(c)
	Fiscal Year	Actual (or Proposed) Capital Spend (000s)	Activity (or Planned Activity)
1	2020	459	Planning & Engineering
2	2021	544	Engineering
3	2022	2,067	Engineering & long lead material procurement
4	2023	1,574	Engineering & long lead material procurement
5	2024	2,986	Temp Transformer civil construction of foundations, ducts & grounding
6	2025	6,782	Temp Transformer materials procurement, electrical construction and commissioning. New Admiral substation engineering, permitting and long lead materials procurement.
7	2026	6,998	New substation engineering, material procurement, civil and electrical construction

b. Please see the table below for the original Admiral Street substation and distribution cost estimates for the preferred solution derived in the Area Study. This can be found in Table 1 of the Providence Area Study Implementation Plan.

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Asset Condition

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		FY 2019 (000s)	FY 2020 (000s)	FY 2021 (000s)	FY 2022 (000s)	FY 2023 (000s)	FY 2024 (000s)	FY 2025 (000s)	FY 2026 (000s)
1	Distribution Line	290	1,810	4,680	8,120	8,340	10,390	10,020	7,090
2	Substation		250	500	2,300	1,870	4,860	810	

c. Please see the annual proposed spend for Auburn along with a general description of work planned for each year. Please note, this forecast has changed since the completion of the Area Study. The Company has adjusted this project for inflation and scope changes.

The table below shows the current proposed spend for Auburn.

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Asset Condition

Distribution-Line

	(a)	(b)	(c)
	Fiscal Year	Actual (or Proposed) Capital Spend (000s)	Activity (or Planned Activity)
1	2025	244	Planning & Engineering
2	2026	1,100	Engineering, permitting and long lead material procurement, D-Line construction
3	2027	5,192	Engineering, permitting and long lead material procurement, D-Line construction
4	2028	11,632	Engineering, permitting and long lead material procurement, D-Line construction
5	2029	9,042	D-Line construction

Substation

	(a)	(b)	(c)
	Fiscal Year	Actual (or Proposed) Capital Spend	Activity (or Planned Activity)
1	2027	1,057	Engineering, permitting and long lead material procurement
2	2028	2,112	Engineering, permitting and long lead material procurement
3	2029	6,336	Civil & electrical construction
4	2030	832	Electrical construction & commissioning

Regarding sequencing, Admiral Street does not need to be in service before Auburn (or vice versa). The Company determined from a resourcing and affordability standpoint that the projects should be done sequentially, and Admiral Street has more asset condition and safety concerns, so it was prioritized to be completed first.

Prepared by or under the supervision of: Ryan Constable

Division 1-18
Asset Condition

Request:

Provide a list of major equipment required for Admiral St. substation, dates ordered (or to be ordered), scheduled delivery (or anticipated delivery), and cost.

Response:

The Company considers major equipment to be equipment that is forecasted to individually cost more than $50,000. Please see the table below for a list of the major equipment required for the Admiral Street Substation.

For definitions, the Order Date is when the Purchase Order was sent out to the awarded Supplier, and the Delivery Date is when the equipment is expected to arrive. The procurement process, including necessary Request for Proposal (RFP) cycles and negotiation, occurs before the Order Date.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Substation Transformer	2	3/14/2022	1/5/2024 *Received*	$ 3,525,600.00
2	Metalclad Switchgear Power Control Center	1	5/13/2024*	12/31/2025	$ 4,696,586.00
3	Capacitor Banks	2	12/17/2023	12/31/2025	$ 654,758.40

**The procurement process for this Switchgear began in July 2023 and took longer than anticipated. At the time of RFP Publication, Suppliers were still recovering from pandemic related labor and material shortages and backups in their quotations department. The RFP cycle was elongated due to requests for extension for original bids and a slow response time from Suppliers to all subsequent Company clarifications and negotiations.*

Prepared by or under the supervision of: Daniel Glenning

Division 1-19
Asset Condition

Request:

Provide a list of major equipment required for Auburn substation, anticipated order dates, anticipated delivery, and cost.

Response:

The Company considers major equipment to be equipment that is forecasted to individually cost more than $50,000. Please see the table below for a list of the major equipment required for the Auburn Substation project.

This substation is early in the project lifecycle. At this time, the Company is completing early stage design and the list of equipment required is still being developed. The procurement process, including necessary Request for Proposal ("RFP") cycles and negotiation occurs before the Order Date.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Substation Transformer	2	March 31, 2026	December 31, 2028	$ 5,000,000.00
2	Metal Clad Capacitor Banks	2	September 30, 2027	December 31, 2028	$ 750,000.00
3	Control Enclosure	1	December 31, 2026	December 31, 2028	$ 3,000,000.00

Based on lead times of two to three years, it is anticipated that the transformer procurement process will begin in fiscal year 2026 as the first procurement event for this project.

Prepared by or under the supervision of: Daniel Glenning

Division 1-20
Asset Condition

Request:

It is the Division's understanding that the Company is considering relocating Gate II Substation due to access concerns. If not, please clarify the future plans for Gate II Substation. If the substation will be relocated, why is RIE planning to replace substation equipment now? Will the new equipment be utilized in the relocated substation?

Response:

Currently, the Company is re-evaluating the Gate II substation within a Newport Area Study. Relocating the substation, as well as direct asset replacement, will be considered as alternatives to the asset condition and access issues. The current cash flow, shown on Bates page 82, represents replacement of the grounding transformer, and it remains in the budget to note the pending Gate II work. The Company will update the cash flow when the study is completed and the ultimate scope is determined. Rhode Island Energy is not planning to replace substation equipment now. The $93,000 in FY 2026 will be used towards the rescoping.

Division 1-21
Asset Condition

Request:

In the event of equipment failure in the Gate II substation, is the Company able to serve load from other sources?

Response:

Yes, the Company can serve area load with other surrounding substations in the event of equipment failure at the Gate II substation. Certain equipment failure at the Gate II substation would result in sustained reconfiguration with an elevated reliability risk for longer than the one-year procurement period.

Prepared by or under the supervision of: Ryan Constable

Division 1-22
Asset Condition

Request:

What is the status of Gate II substation engineering and design? Has the Company ordered and/or made payments for any equipment?

Response:

The Gate II substation is being reviewed in Distribution Planning. The Company has not ordered equipment.

Prepared by or under the supervision of: Ryan Constable

Division 1-23

Asset Condition

Request:

Regarding Hospital #146 equipment replacement, the Company's transformer loading report indicates that two existing 4.16 MVA transformers serve less than 6 MVA of load. What transformer size is the Company proposing in its recommended replacement plan and how was the size determined? Discuss any space limitations or rearrangements expected at the site to accommodate new and higher capacity equipment.

Response:

There are no higher capacity transformers included in this project. The scope for the Hospital #146 equipment replacement project includes replacement of the existing 2.8/3.5 MVA – 23/4.16 kV transformers with units of the same size. These size transformers are required due to the load served at this station and space constraints of the existing site. The space limitations at this site preclude the use of standard size transformers.

Division 1-24
Asset Condition

Request:

Regarding the Kingston project summary (Bates page 83), the Company indicates that failure of certain arrestors have a history of damaging other nearby parts. Please elaborate on other instances of history of damage to nearby parts. Is the potential damage due to the current type of arrestor? If so, has the Company considered proactive replacement until the future comprehensive station work is performed?

Response:

Silicon carbide arresters, and other porcelain arresters, have a history throughout the industry of occasional violent failure. The Company recently experienced an arrester failure at the Warren substation that subsequently damaged nearby transformer high voltage bushings and adjacent arresters. All three bushings and arresters were replaced as a result.

Until recently, the Company did not consider the proactive replacement of the silicon carbide arresters because it is sensitive to early obsolescence. Since the area study was completed, Company specialists attended a Doble (Industry recognized specialist with 100 years of experience in this discipline) conference, which recommended the immediate replacement of these arresters beyond the age of imminent failure. The Company is evaluating the number of arresters on its system and will be proposing proactive replacement to avoid imminent failure. The Kingston arresters have been identified as potential candidates for proactive replacement. Although this asset condition may be addressed prior to the completion of the substation rebuild, it would not lead to the deferral of the project because the project addresses 23kV devices, which already are obsolete and unreliable. These include circuit breakers, transformers, and switchgear, all which have long lead times for replacement.

Division 1-25
Asset Condition

Request:

The Company indicates that loss of the supply line at Kingston impacts 3000 customers until field switching can be completed or repairs made. How long does it take to complete field switching? After switching, is service restored to all customers?

Response:

Distribution switching typically takes anywhere from 30 minutes to two hours, depending on the timing of the issues and how far field crews must travel. However, for loss of supply at Kingston, the number of switching steps between sub-transmission and distribution ties is expected to take 4 to 6 hours. All of the customers can be restored after this switching. The Company's Distribution Control Center ultimately decides how much switching is to be completed during an event, with the goal of picking up as many customers as possible, while also keeping equipment within emergency ratings.

Prepared by or under the supervision of: Ryan Constable

Division 1-26
Asset Condition

Request:

The Company indicates that failure of the Kingston #1 and #2 transformers or #1 and #2 metal clad switchgears would affect 2200 and 800 customers. In each case, please clarify whether failure of either or both assets affects customers. Are the impacted customers able to be served from alternate feeds? If the Company is considering failure of two pieces of equipment, explain if RIE's planning guidelines normally assume that more than one major asset fails at a time when planning for contingencies.

Response:

For each case, failure of either asset impacts the stated customers. Yes, the impacted customers would be able to be served from alternate feeds, which in this case, would be distribution feeder ties. This would result in a sustained reconfiguration with an elevated reliability risk to the Kingston substation customers and surrounding station customers for a procurement period of two to three years.

The Company is not considering the failure of two pieces of equipment at the same time. For contingency analysis, the Company considers the loss of a single element when analyzing unserved load conditions per the planning criteria. However, contingency analysis is not normally applied to defer the replacement of equipment at the end of its useful life. The information provided above would not be used to defer or prioritize the work; however, it can be used to understand the importance of the project.

Division 1-27
Asset Condition

Request:

What is the Company's rationale for specifying a breaker and a half scheme on the high and low side of the proposed Kingston substation rebuild rather than utilizing lower cost distribution ties? What are the incremental costs and benefits of the proposed schemes over lower cost designs?

Response:

A breaker and a half station design is the Company's standard station design. Breaker and a half station schemes, common across the industry, provide high reliability and resiliency and control maintenance costs. These designs are cost competitive with other typical station designs such as main/transfer bus, main/tie/main, ring bus, and double breaker/bus schemes.

In the specific case of the proposed Kingston substation, there are two 23kV sources that will feed the substation and then continue as a primary source to two downstream substations and an alternative source to two other substations. The breaker and a half scheme provides a cost effective design that allows for quick fault isolation upon a line fault and will limit the reliability impact to the proposed Kingston substation or other downstream substations.

The breaker and a half design also allows the operation crews to switch at the substation instead of using a feeder tie to supply the impacted feeder. The benefits of this include limiting voltage drop along the impacted feeder to match the voltage drop during the nominal configuration, eliminating the load increase that the feeder conductors will experience and reducing the risk of a line fault impacting both feeders.

Station designs and/or rebuilds are not typically compromised through use of distribution ties, particularly ties that are not automated or remote controllable through grid modernization efforts. The Company has not quantified the incremental cost of the breaker and a half design versus use of distribution ties because this is not something the Company would consider standard or typical within the industry.

Prepared by or under the supervision of: Ryan Constable

Division 1-28
Asset Condition

Request:

For Kingston, the Company's transformer loading report indicates that two existing 7.9 MVA transformers serve 8.5 MVA of load. What transformer size is the Company proposing in its recommended replacement plan and how was the size determined? Discuss any space limitations or rearrangements expected at the site to accommodate new and potentially higher capacity equipment.

Response:

The scope for the Kingston #131 equipment replacement project includes replacement of the existing 6.25/7 MVA – 23/4.16 kV transformers with 7.5/9.375 MVA units. These are the standard size transformers for stations of this type. Use of standard transformer sizes results in a number of operational efficiencies, including engineering, design, procurement consistency, simplifying stocked spare parts, and easier replacement upon failure, which also reduces spare and mobile transformer requirements.

Although there are space limitations at this site, the standard size transformers can be accommodated in the redesign of the station.

Division 1-29
Asset Condition

Request:

Why does the Company propose commencing Merton in FY 2027 when the Long Range Plan indicates the need to reevaluate the previous study recommendation due to new customer loads and 4kV capacity constraints? (Bates page 72).

Response:

The Company understands the purpose of the Long Range Plan to be providing visibility of pending work. With this goal, the Company included the Merton Substation work starting in FY 2027 for awareness. The Company has noted that as the restudy evaluates the need for the area, the final design for the Merton work will be communicated as soon as possible and updated in next year's ISR Plan.

Prepared by or under the supervision of: Ryan Constable

Division 1-30

System Capacity & Performance

Request:

For the following list of substation and/or distribution line System Capacity related projects, provide the information requested below:

East Providence
Warren Substation
New Lafayette
Weaver Hill
Chase Hill Substation
All Other Area Study Projects (capacity related) noted in Attachment 3 of the Long Range Plan (Bates page 99)

a. The related Area Study and completion date.
b. A description of the system issue identified in the Area Study and how the proposed project resolves the issue.
c. Capacity ratings and projected loads at the time of the study, identifying the specific thermal and/or contingency violations. Indicate the anticipated year of the violation.
d. The actual loads occurring since the time of the Area Study in comparison to projections.
e. Thermal and/or contingency violations based on current and updated load projections. Indicate the anticipated year of the violation.
f. The Company's assessment as to whether loads and/or system issues have materialized as projected in the Area Study.
g. Discuss any interim projects that have materially changed loads, system capacities, or related items which would prompt a reevaluation of the proposed project.
h. Summarize the Company's justification for advancing the project in the near term taking into account current loads and updated projections.

Response:

Please note, the electric distribution system is not planned to predict actual loads nor is that the intent of the forecasting process. The Company's planning process is based on extreme weather scenario forecasts where the appropriate evaluation is whether the actual loads exceeded the forecasted value, not if the actual values are equal to the forecasted values.

If actual values are less than forecasted values, then the planning process is sufficient. If actual values exceed the forecasted values, then the planning process would need to be reevaluated. This is common within the industry. For example, ISO-NE uses a 90/10 extreme weather scenario in planning. To be cost effective, the extreme weather scenario should be marginally

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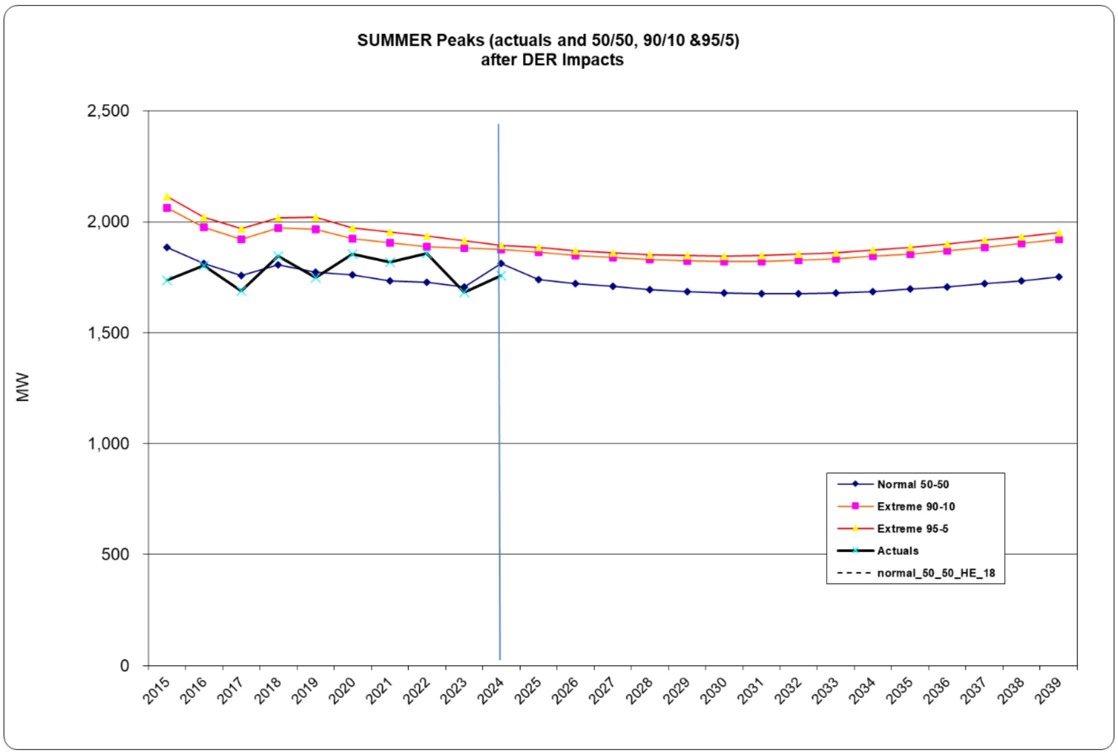
System Capacity & Performance

greater than the actual values. This is demonstrated by the following chart where the orange extreme 95-5 line can be seen marginally higher than several of the actual historic loads.



East Providence and Warren Substation

a. The Area Study is the East Bay Study; the completion date is August 2015.

b. The East Bay Study is a comprehensive plan that addresses sub-transmission and substation asset condition and contingency issues by expanding several stations which enables the retirement of most of the 4kV and 23kV infrastructure in the East Bay. Specifically, the plan proposes to solve these issues by the construction of a new substation in East Providence, the expansion of the Warren Substation and the rebuilding of the Phillipsdale Substation. All these solutions aim to solve the asset condition, capacity, and contingency issues identified in the study.

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System Capacity & Performance

The East Providence Substation and the Warren Expansion Project are critical components of the plan. However, these projects alone cannot address all asset condition, capacity, and contingency issues within its service area, and as identified in the study. Specifically, the East Providence Substation will enable the retirement of the Waterman Ave substation, which has significant asset condition issues and out-of-phase feeders. Additionally, it will provide capacity relief and address contingency load-at-risk issues for several Wampanoag feeders.

The East Providence Substation will also facilitate shifting Wampanoag feeders southward, facilitating the retirement of the Kent Corners Substation. Kent Corners, a 4kV station, currently has several asset condition issues and lacks any feeder ties. This shift will also support the retirement of the Barrington Substation by transferring the load of its feeder loads to circuits originating at the Wampanoag and Warren Substation. Like Kent Corners, and the Waterman Ave substation, the Barrington Substation also has significant asset condition issues.

The construction of East Providence Substation will facilitate the broader retirement of the 23kV system, which suffers from asset condition issues on both its distribution line and substation components, and which otherwise would require comprehensive upgrades.

The Warren Expansion Project will allow the retirement of the Barrington Substation because it will allow the transfer of some of its load to two new circuits originating from the Warren Substation. Additionally, this project will support the retirement of portions of the 23kV system in the southern East Bay Area. Similar to the northern part of the East Bay, this system suffers from asset condition issues across its distribution line and distribution substation components. The project also will help solve some of the loading and contingency issues identified in the study.

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System Capacity & Performance

c. The tables below show the capacity ratings and projected loads at the time of the study, identifying the specific thermal and/or contingency issues and year of issue, as identified by the red highlight.

TABLE 4.1.1 - Projected Summer Normal Feeder Loading

Substation	Fdr	2020		2026		2028		2030	
		Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
BARRINGTON	4F1	330	64%	344	67%	350	68%	355	69%
BARRINGTON	4F2	468	92%	488	96%	496	97%	504	99%
BRISTOL	51F1	519	81%	543	84%	552	86%	561	87%
BRISTOL	51F2	481	91%	503	95%	511	96%	520	98%
BRISTOL	51F3	431	86%	451	90%	458	91%	466	93%
WAMPANOAG	48F1	488	97%	512	102%	520	104%	528	105%
WAMPANOAG	48F2	445	86%	466	91%	474	92%	482	94%
WAMPANOAG	48F3	559	110%	585	115%	595	117%	604	119%
WAMPANOAG	48F4	542	102%	568	107%	577	109%	586	111%
WAMPANOAG	48F5	461	95%	483	100%	491	101%	498	103%
WAMPANOAG	48F6	420	79%	440	83%	447	84%	455	86%
WARREN	5F1	379	89%	392	92%	398	94%	404	95%
WARREN	5F2	396	91%	411	95%	416	96%	422	97%
WARREN	5F3	393	76%	407	79%	413	80%	419	81%
WARREN	5F4	466	91%	483	95%	490	96%	496	97%
OUT OF PHASE FEEDERS									
PHILLIPSDALE	20F1	336	79%	352	83%	358	84%	363	85%
PHILLIPSDALE	20F2	398	94%	417	98%	424	100%	430	101%
WATERMAN AVE	78F3	263	64%	276	68%	281	69%	285	70%
WATERMAN AVE	78F4	248	61%	260	64%	264	65%	268	66%
4.16kV POCKET OF LOAD									
KENT CORNERS	47J2	336	82%	352	86%	358	88%	364	89%
KENT CORNERS	47J3	349	86%	366	90%	372	91%	378	93%
KENT CORNERS	47J4	382	94%	400	98%	406	100%	413	101%

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System Capacity & Performance

TABLE 4.1.2 - Calculated MWh exposure and Un-Served Load on Feeders

Substation	Feeder	MWh Exposure	Un-Served MW
BARRINGTON 4	4F1	18.2	3.45
BARRINGTON 4	4F2	22.7	2.91
BRISTOL 51A	51F1	24.7	2.36
BRISTOL 51A	51F2	25.2	4.06
BRISTOL 51A	51F3	21.1	2.52
WAMPANOAG 48	48F1	25.6	4.25
WAMPANOAG 48	48F2	23.5	4.52
WAMPANOAG 48	48F3	29.3	3.80
WAMPANOAG 48	48F4	42.0	10.31
WAMPANOAG 48	48F5	21.6	2.89
WAMPANOAG 48	48F6	26.2	5.15
WARREN 5	5F1	19.4	3.47
WARREN 5	5F2	24.5	5.00
WARREN 5	5F3	22.6	4.18
WARREN 5	5F4	21.0	0.99
WATERMAN AVENUE 78	78F3*	5.4	0.00
WATERMAN AVENUE 78	78F4*	5.3	0.00
PHILLIPSDALE 20	20F1*	23.9	5.67
PHILLIPSDALE 20	20F2*	13.6	1.08

* NOTE: These feeders are not in-phase with the remainder feeders. Any switching involving these feeders will require customers to be exposed to a short duration outage.

d. See Attachment DIV 1-30-1_EB for information showing the actual loads occurring since the time of the Area Study in comparison to projections. Additionally, for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections. Also see the response to Division 1-35.

e. The normal and contingency loading issues based on current and updated load projections are shown in the Company's responses to Division 1-35 and Division 1-36.

f. For any project, the Company assesses all factors, not solely loading when determining project prudency. The East Bay Study identified several persistent system asset condition issues that require attention. These issues include substantial sub-transmission line asset issues and Kent Corners, Waterman, and Barrington substation asset issues.

Regarding loading, actual loads have been less than forecasted, as expected. Weather adjusted values are lower than forecasted for some circuits and higher than forecasted for other circuits, with the overall area weather adjusted loading lower than forecasted. Attachment Division 1-35 to the Company's response to Division 1-35 shows no issues with projected summer normal feeder loading. Attachment DIV 1-36 to the Company's response to Division 1-36 shows many of the contingency loading issues persist.

System Capacity & Performance

g. There are no interim projects that have materially changed load or system capacity. Also see the Company's response to Division 1-37. The period since the study includes the pandemic period which may have affected load levels.

   There have been project execution issues that have arisen. These issues are described in the Company's responses to Division 1-39 and Division 1-43.

h. Please refer to the tables and the information in subparts a. through g., above for the Company's justification for advancing the project in the near term, taking into account current loads and updated projections.

   As discussed in subpart b., above, the East Bay Study identified a comprehensive plan that addresses sub-transmission and substation asset condition and contingency issues by expanding several stations which enables the retirement of most of the 4KV and 23kV infrastructure in the East Bay. Specifically, the plan proposes to solve these issues by the construction of a new substation in East Providence, the expansion of the Warren Substation and the rebuilding of the Phillipsdale Substation. Although the normal loading issues may have been mitigated, all these solutions aim to solve the asset condition and contingency issues that were identified in the study and reaffirmed above.

   The East Providence Substation and the Warren Expansion Project are critical components of the plan. However, these projects alone cannot address all asset condition, capacity, and contingency issues within its service area, and as identified in the study. Specifically, the East Providence Substation will enable the retirement of the Waterman Ave substation, which has significant asset condition issues and out-of-phase feeders. Additionally, it will provide address contingency load-at-risk issues for several Wampanoag feeders as confirmed by the response to Division 1-36.

   The East Providence Substation will also facilitate shifting Wampanoag feeders southward, facilitating the retirement of the Kent Corners Substation. Kent Corners, a 4kV station, currently has several asset condition issues and lacks any feeder ties. This shift will also support the retirement of the Barrington Substation by transferring the load of its feeder loads to circuits originating at the Wampanoag and Warren Substation. Like the Kent Corners and the Waterman Ave substation, the Barrington Substation also has significant asset condition issues.

   The construction of East Providence Substation will facilitate the broader retirement of the 23kV system, which suffers from asset condition issues on both its distribution line and substation components, which otherwise would require comprehensive upgrades.

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The Warren Expansion Project will allow the retirement of the Barrington Substation because it will allow the transfer of some of its load to two new circuits originating from the Warren Substation. Additionally, this project will support the retirement of portions of the 23kV system in the southern East Bay Area. Similar to the northern part of the East Bay, this system suffers from asset condition issues across its distribution line and substation components. The project also will help solve some of the contingency issues.

New Lafayette

a. The Area Study is the South County East Area Study; completion date was March of 2018.

b. The primary drivers of the new Lafayette Substation are contingency load at risk (5 feeders and 1 transformer), and normal loading (3 feeders over summer normal ratings), system reliability on the 34.5kV supply system, and asset condition of the 34.5kV supply system. The new substation, along with other common area study projects, would provide additional system capacity for contingencies and allow the Company to retire the sub-transmission line assets.

c. See the following tables from the original area study. The expected years with loading issues are those years highlighted in red:

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TABLE 9.3.1 – Feeder Loading Before Improvements

Substation	Feeder	SN Rating (Amps)	Projected Load 2018 Amps	2018 %SN	2022 Amps	2022 %SN	2026 Amps	2026 %SN	2030 Amps	2030 %SN
BONNET 42	42F1	525	515	98%	522	99%	535	102%	550	105%
LAFAYETTE 30	30F1	350	261	75%	265	76%	271	78%	279	80%
LAFAYETTE 30	30F2	530	457	86%	464	88%	475	90%	489	92%
OLD BAPTIST ROAD 46	46F1	530	422	80%	427	81%	438	83%	450	85%
OLD BAPTIST ROAD 46	46F2	530	376	71%	381	72%	390	74%	401	76%
OLD BAPTIST ROAD 46	46F3	565	362	64%	368	65%	376	67%	387	69%
OLD BAPTIST ROAD 46	46F4	594	478	80%	484	82%	496	84%	510	86%
PEACEDALE 59	59F1	409	165	40%	167	41%	171	42%	176	43%
PEACEDALE 59	59F2	492	326	66%	331	67%	339	69%	349	71%
PEACEDALE 59	59F3	492	478	97%	484	98%	496	101%	510	104%
PEACEDALE 59	59F4	492	190	39%	193	39%	197	40%	203	41%
QUONSET 83	83F1	645	115	18%	343	53%	351	54%	408	63%
QUONSET 83	83F2	490	121	25%	199	41%	260	53%	315	64%
QUONSET 83	83F3	645	329	51%	334	52%	342	53%	352	55%
WAKEFIELD 17	17F1	602	471	78%	478	79%	489	81%	503	84%
WAKEFIELD 17	17F2	510	508	100%	515	101%	527	103%	542	106%
WAKEFIELD 17	17F3	597	487	82%	494	83%	506	85%	520	87%
TOWER HILL 88	88F1	530	387	73%	392	74%	402	76%	413	78%
TOWER HILL 88	88F3	550	443	81%	449	82%	460	84%	473	86%
TOWER HILL 88	88F5	530	410	77%	416	78%	426	80%	438	83%
TOWER HILL 88	88F7	530	404	76%	410	77%	420	79%	432	81%
QUONSET 83	83F4	600	283	47%	287	48%	294	49%	302	50%

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TABLE 9.3.2 - Feeder MWh "Exposure" Before Improvements

Substation	Feeder	Un-Served (MW)	MWHr Exposure
BONNET	42F1	4.99	28.4
LAFAYETTE	30F1	0.00	6.4
LAFAYETTE	30F2	2.59	19.5
OLD BAPTIST RD	46F1	1.80	15.9
OLD BAPTIST RD	46F2	1.53	13.6
OLD BAPTIST RD	46F3	0.00	11.2
OLD BAPTIST RD	46F4	0.00	13.8
PEACEDALE	59F1	0.00	3.6
PEACEDALE	59F2	0.00	7.7
PEACEDALE	59F3	0.00	12.8
PEACEDALE	59F4	0.00	4.3
QUONSET	83F1	0.00	3.6
QUONSET	83F2	0.00	6.6
QUONSET	83F3	0.00	7.1
WAKEFIELD	17F1	7.70	34.6
WAKEFIELD	17F2	3.00	24.1
WAKEFIELD	17F3	0.00	14.0
TOWER HILL	88F1	0.00	11.4
TOWER HILL	88F3	0.00	11.6
TOWER HILL	88F5	3.88	20.5
TOWER HILL	88F7	0.00	10.6

The Tower Hill substation is a single transformer substation with approximately 36 megawatts of load in 2017 (also the year of issue), for loss of the station transformer, there is approximately 19 megawatts of unserved load during peak conditions, resulting in 495 megawatt*hours of load-at-risk.

d. See Attachment DIV 1-30-2 for information showing the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

e. Normal loading and contingency load-at-risk based on current and updated load projections are shown in the tables below. Yellow highlights show values approaching limits and red highlights show values at or above limits.

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South County East Feeder Analysis

Study Area	Substation	Voltage (kV)	Feeder	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	SE Rating (Amps)	Actual Load		Projected Load						
								2023		2024			2031		2038	
								Amps	%SN	Amps	N-1	%SN	Amps	%SN	Amps	%SN
South County East	BONNET 42	12.47	42F1	Transformer	7.5/9.375 MVA	525	566	402	77%	437	129	83%	447	85%	478	91%
South County East	LAFAYETTE 30	12.47	30F1	Bus Conductor	4/0 Cu HD 7 Strd.	526	612	254	48%	307	305	58%	314	60%	336	64%
South County East	LAFAYETTE 30	12.47	30F2	OH Line	477 Al Spacer Cable - 15kV	530	612	270	51%	403	209	76%	413	78%	441	83%
South County East	OLD BAPTIST ROAD 46	12.47	46F1	OH Line	477 Al Spcr	530	612	303	57%	329	283	62%	337	64%	361	68%
South County East	OLD BAPTIST ROAD 46	12.47	46F2	OH Line	477 Al Spcr	530	612	251	47%	289	323	55%	296	56%	316	60%
South County East	OLD BAPTIST ROAD 46	12.47	46F3	UG Cable	1000 Cu	565	612	297	53%	326	286	58%	333	59%	357	63%
South County East	OLD BAPTIST ROAD 46	12.47	46F4	UG Cable	1000 Cu	594	612	274	46%	298	314	50%	305	51%	327	55%
South County East	PEACEDALE 59	12.47	59F1	Regulator	250 kVA 7.2kV - 55C	409	489	135	33%	147	342	36%	151	37%	161	39%
South County East	PEACEDALE 59	12.47	59F2	UG Cable	1C 750 Al XLPE CN DB	492	515	260	53%	282	233	57%	289	59%	309	63%
South County East	PEACEDALE 59	12.47	59F3	UG Cable	750 Al DB	492	650	389	79%	423	227	86%	433	88%	463	94%
South County East	PEACEDALE 59	12.47	59F4	OH Line	336 Al Spacer Cable - 15kV	425	515	167	39%	182	333	43%	371	87%	397	93%
South County East	QUONSET 83	12.47	83F1	UG Cable	1000 Cu	555	645	135	24%	153	492	28%	226	41%	242	44%
South County East	QUONSET 83	12.47	83F2	UG Cable	1000 Cu	555	680	356	64%	542	138	98%	568	102%	608	110%
South County East	QUONSET 83	12.47	83F3	UG Cable	1000 Cu	515	680	277	54%	301	379	58%	355	69%	380	74%
South County East	WAKEFIELD 17	12.47	17F1	Transformer	7.5/9.375 MVA	602	612	434	72%	472	140	78%	483	80%	517	86%
South County East	WAKEFIELD 17	12.47	17F2	OH Line	336 Al	515	515	457	89%	497	18	96%	508	99%	544	106%
South County East	WAKEFIELD 17	12.47	17F3	Transformer	7.5/9.375 MVA	597	626	417	70%	453	173	76%	464	78%	496	83%
South County East	TOWER HILL 88	12.47	88F1	OH Line	477 Al Spcr	530	650	397	75%	462	188	87%	473	89%	506	95%
South County East	TOWER HILL 88	12.47	88F3	UG Cable	1000 Cu	550	645	403	73%	439	206	80%	449	82%	480	87%
South County East	TOWER HILL 88	12.47	88F5	OH Line	477 Al Spcr	530	650	325	61%	382	268	72%	391	74%	419	79%
South County East	TOWER HILL 88	12.47	88F7	OH Line	477 Al Spcr	530	650	335	63%	364	286	69%	373	70%	399	75%
South County East	QUONSET 83	12.47	83F4	UG Cable	1000 Cu	515	650	229	45%	365	285	71%	421	82%		
South County East	LAFAYETTE 30	12.47	89F1	TBD	TBD	530	650						0	0%		
South County East	LAFAYETTE 30	12.47	89F2	TBD	TBD	530	650						0	0%		
South County East	LAFAYETTE 30	12.47	89F3	TBD	TBD	530	650						0	0%		
South County East	LAFAYETTE 30	12.47	89F4	TBD	TBD	530	650						0	0%		

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Substation	Feeder	2024 Un-Served (MW)	2024 MWHr Exposure
BONNET	42F1	2.30	18.5
LAFAYETTE	30F1	0.00	0.0
LAFAYETTE	30F2	1.09	14.3
OLD BAPTIST RD	46F1	0.00	6.1
OLD BAPTIST RD	46F2	0.00	0.0
OLD BAPTIST RD	46F3	0.00	3.4
OLD BAPTIST RD	46F4	0.00	2.8
PEACEDALE	59F1	0.00	1.7
PEACEDALE	59F2	0.00	0.8
PEACEDALE	59F3	0.00	13.9
PEACEDALE	59F4	0.00	0.0
QUONSET	83F1	1.55	7.9
QUONSET	83F2	0.13	16.5
QUONSET	83F3	0.00	5.5
QUONSET	83F4	0.00	7.6
WAKEFIELD	17F1	6.30	30.9
WAKEFIELD	17F2	4.90	27.9
WAKEFIELD	17F3	0.71	14.6
TOWER HILL	88F1	0.00	14.5
TOWER HILL	88F3	1.03	14.1
TOWER HILL	88F5	1.55	15.8
TOWER HILL	88F7	1.45	14.5

In 2024 The Tower Hill substation is predicted to have approximately 31.8 megawatts of load, for loss of the station transformer, there is approximately 19.6 megawatts of unserved load during peak conditions, resulting in 480 megawatt*hours of load-at-risk, which is over planning guidelines.

f. For any project, the Company assesses all factors, not solely loading when determining project prudency. The South County East Study identified several persistent system asset condition issues that require attention. There are two 34.5 kV supply lines in the area built in the 1930's (Davisville 84T3 & Kent County 3312). A condition assessment was performed on these lines, at the time of the study, with consultation from Operations and Design. Large portions of these lines are installed in rights-of-way (ROW) with limited access or through backyards with restricted access. The ROW contains wetlands and water crossings. A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. Study Table 4.3.1, reproduced below, contains a summary of the asset age data. Approximately 14 miles of the sub-transmission system would be eliminated by the New Lafayette project.

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Table 4.3.1 – 84T3 Line and 3312 Line Pole Data

84T3 Line		
# of Poles	Age Range	% of Total
48	0 to 40	19%
101	40 to 60	39%
110	60 plus	42%
259	Total	100%

3312 Line		
# of Poles	Age Range	% of Total
89	0 to 40	35%
52	40 to 60	21%
110	60 plus	44%
251	Total	100%

Regarding loading, the actual loads have remained below the forecasts, as expected. Weather adjusted values are lower than forecasted for some circuits and higher than forecasted for other circuits, with the overall area weather adjusted loading lower than forecasted. Subpart e, above, shows that contingency issues persist for three of the five original circuits.

g. A fourth feeder out of Quonset Substation was added from the time of the study completion to today, which resulted in shifting of load, especially on the Old Baptist 46F4 circuit. Additional spot load increases on Quonset Substation have also caused increases in substation utilization and reduction in available capacity during contingency load at risk situations. The period since the study includes the pandemic period which may have affected load levels.

h. As originally outlined in the South County East Area Study, the distribution system in the area is highly utilized with numerous contingency and asset issues. The projects outlined in the Study, the Common projects as well as the new Lafayette Substation, continue to be required in the near term. These projects, as a comprehensive plan, will provide both normal and the contingency capacity relief to the area and will allow the Company to retire equipment with asset conditions and operational issues as described in subpart f., above.

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Weaver Hill

a. The related area study for the Weaver Hill projects is the Central RI West Area Study; it was substantially completed in the third quarter of 2021, with revision 1 issued September 2022.

b. The justification for the Weaver Hill Substation was based on a need for additional capacity in the area to address a projected summer normal overload at Hopkins Hill (63F6) as well as a highly loaded feeder at Coventry (54F1) and to resolve voltage conditions along remote sections of both feeders. Two (2) new substation locations were investigated to be utilized to build a modular substation/feeder to offload these two feeders – one at Weaver Hill Road, West Greenwich and one near Pine Hill Road, Exeter. The least cost recommended option is the Weaver Hill Road option to extend subtransmission from Nooseneck Hill and Weaver Hill Roads, West Greenwich to a Rhode Island Energy owned property off pole #64 Weaver Hill Road and install a 7.5/9.375 MVA transformer and one modular feeder position with distribution line work for a new feeder to be made up of parts of Coventry 54F1 and Hopkins Hill 63F6.

c. See the following tables from the original area study. The expected years of issues are those years that are highlighted in red. In this case, the issues are shown in 2020 and persist until 2035.

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Weaver Hill

Substation	ID	OH Feeder UG Feeder	'20 % SN	'35 %SN
ANTHONY 64	T1	64F1	55%	55%
ANTHONY 64	T2	64F2	45%	45%
COVENTRY 54	T1	54F1	93%	94%
DIVISION ST 61	T1	61F1	76%	77%
DIVISION ST 61		61F3	84%	85%
DIVISION ST 61	T2	61F2	74%	75%
DIVISION ST 61		61F4	83%	84%
DRUMROCK 14		2230	54%	55%
DRUMROCK 14		2232	54%	55%
DRUMROCK 14		2266	68%	69%
HOPE 15	T1	15F1	39%	40%
HOPE 15	T2	15F2	90%	91%
HOPKINS HILL 63	T1	63F1	44%	45%
HOPKINS HILL 63		63F3	59%	60%
HOPKINS HILL 63		63F5	58%	59%
HOPKINS HILL 63	T2	63F2	73%	74%
HOPKINS HILL 63		63F4	78%	79%
HOPKINS HILL 63		63F6	102%	104%
KENT COUNTY 22	T1	3309	44%	45%
KENT COUNTY 22	T2	3310	28%	28%
KENT COUNTY 22	T7	3311	79%	80%
KENT COUNTY 22		3312	54%	55%
KENT COUNTY 22	T5	22F1	72%	73%
KENT COUNTY 22		22F3	56%	57%
KENT COUNTY 22	T6	22F2	83%	84%
KENT COUNTY 22		22F4	51%	52%
KENT COUNTY 22		22F6	78%	79%
NATICK 29	T1	29F1	104%	106%
NATICK 29	T2	29F2	71%	72%
NEW LONDON 150	T2	150F2	67%	68%
NEW LONDON 150		150F4	64%	65%
NEW LONDON 150		150F6	153%	155%
NEW LONDON 150		150F8	53%	54%
TIOGUE AVE 100	T1	100F1	81%	83%
WARWICK MALL 28	T1	28F1	40%	40%
WARWICK MALL 28	T2	28F2	30%	30%

The Weaver Hill project addresses the 54F1 and 63F6 loading issues.

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Weaver Hill

d. See Attachment DIV 1-30-3 for information showing the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

e. Normal loading based on current and updated load projections are shown in the tables below. Yellow highlights show values approaching limits and red highlights show values at or above limits.

Central RI West Feeder Analysis											
Study Area	Substation	Voltage (kV)	Feeder	Actual Load 2023		Projected Loads 2024		2031		2038	
				Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
Central RI West	COVENTRY	12.47	54F1	360	68%	407	77%	416	79%	445	85%
Central RI West	HOPKINS HILL	12.47	63F6	409	77%	454	86%	465	88%	497	94%

Note that 36 amps were transferred from the 63F6 in a temporary manner to proactively mitigate the potential overload. If this transfer did not occur, the 63F6 2024 loading would be over 92%. Furthermore because the area circuits are electrically strained, the Company is considering shifting new load that is required by a public entity in this area to the sub-transmission system. This would require additional investment for effective grounding and voltage regulation.

f. For any project, the Company assesses all factors, not solely loading when determining project prudency. The Central RI West Study identified several persistent system voltage and reliability issues that require attention.

Voltage issues can be seen in the following figures.

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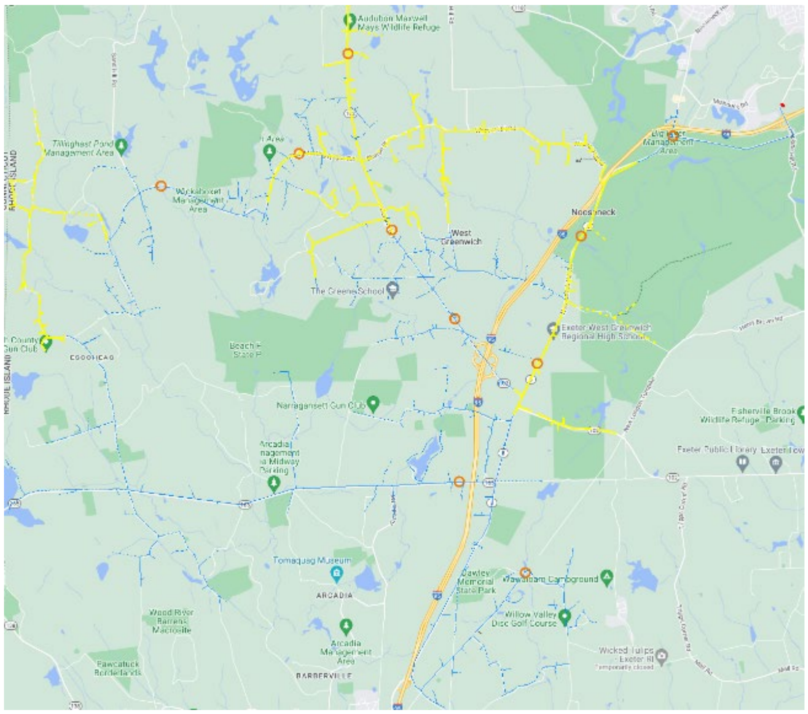
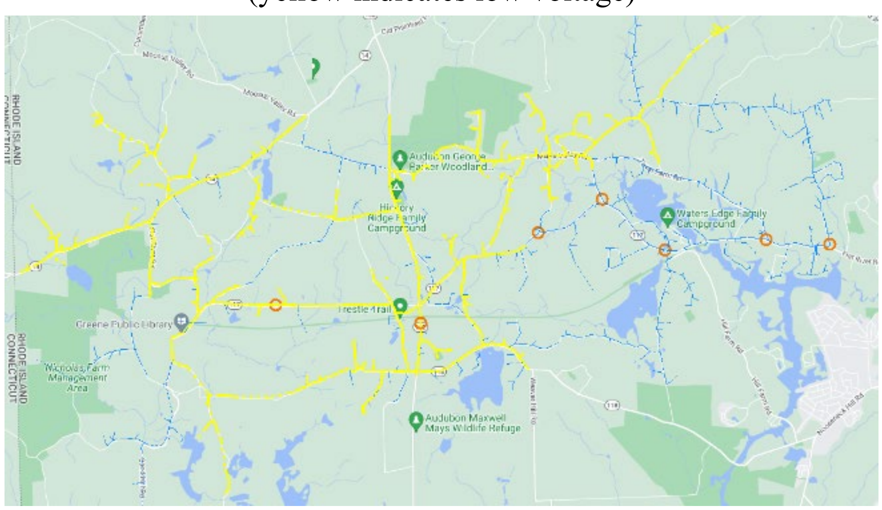
63F6 Voltage
(yellow indicates low voltage)



54F1 Voltage
(yellow indicates low voltage)



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At the time of the study, the 5-year average frequency and duration for the circuits are shown in the following table. The table also shows the current 5-year averages demonstrating the reliability issues persist with frequencies above 1.05 and durations over 71.9 minutes.

	(a)	(b)	(c)	(d)	(e)
	Circuit	Study 5-Yr Average Frequency	Study 5-Yr Average Duration (min)	Current 5-Yr Average Frequency	Current 5-Yr Average Duration (min)
1	54F1	1.679	148.19	2.37	191.9
2	63F6	1.017	99.28	2.04	185.2

Regarding loading, the actual loads have remained below the forecasts, as expected. Weather adjusted values are lower than forecasted for the 54F1 and 63F6. The 63F6 loading is lower than forecasted in part due to a load transfer the Company has already undertaken to avoid the potential overload.

g. In 2022, approximately 36 amps of load were transferred from the 63F6 to mitigate the potential overload. Also, the period since the study includes the pandemic period which may have affected load levels.

h. As originally outlined in the Central RI West Study, the distribution system in the area is highly utilized with numerous issues. The Weaver Hill project continues to be required in the near term as a result of the persistent voltage and reliability issues as described in Part f above.

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Chase Hill Substation

a. The related area study is the South County West Area Study; completion date is completed December 2021.

b. The Chase Hill Substation is a single transformer 115/12.47kV substation, which lacks sufficient feeder ties to pick up customer load, during a loss of normal supply. A contingency loss of the Chase Hill transformer results in unserved load that is projected to exceed Distribution Planning Guidelines, reaching 290 megawatt*hours load-at-risk by 2025. The preferred option is to expand the Chase Hill Substation by adding a new 12.47kV bus and 24/32/40MVA 115/12.47kV transformer. With two transformers, one transformer can pick up the entire substation load in the event of losing the other transformer, eliminating the unserved load.

c. The table below shows the capacity ratings and projected contingency load-at-risk at the time of the study, identifying the specific thermal and/or contingency issues. The expected years of issues are those years that are highlighted in red.

Substation	Tranf. ID.	Rating (MVA)		2020			2025			2030			2035		
		SN	SE	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk
CHASE HILL	2	54.3	63.5	23.9	254.00	10	24	260.00	10.22	24.4	284.00	11.28	24.7	299.00	11.91

d. See Attachment DIV 1-30-4 for information showing the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

e. Please see the following table showing the contingency load-at-risk projections.

Substation	Tranf. ID.	Rating (MVA)		2024			2030			2035			2038		
		SN	SE	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk	MVA	MWHr Exposure	Load At Risk
CHASE HILL	2	54.3	63.5	26	369.20	14.6	26.8	387.70	15.3	27.8	411.90	16.3	28.8	437.00	17.3

f. Yes, the loads and system issues as identified in the system Area Study have materialized/existed since the completion of the study and are projected to continue into the future planning years, especially in regard to contingency load at risk.

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g. There were no interim projects completed that would have materially changed loads. The period since the study includes the pandemic period which may have affected load levels.

h. As originally outlined in the South County West Area Study, the substation is a single transformer station, and the surrounding distribution ties do not provide adequate capacity to pick up enough customers to remain within contingency load-at-risk levels per the Distribution Planning Guidelines.

<u>Nasonville Substation Expansion</u>

a. The related area study is the Northwest RI Area Study, completed January 2021

b. Nasonville substation is a single transformer 115/13.8kV substation that consists of four feeders serving load in the northwest corner of Rhode Island. It is currently very difficult to offload the feeders due to minimal ties to feeders other than Nasonville feeders. A contingency loss of the Nasonville transformer results in unserved load the exceeds the 240 megawatt*hours Distribution Planning Guidelines. The recommended plan for Nasonville substation includes bringing a new 115kV overhead supply line from Woonsocket substation to Nasonville substation and expanding the Nasonville substation by adding a new 13.8kV bus and a 115/13.8kV transformer. With two transformers, one transformer can pick up the entire substation load in the event of losing the other transformer, eliminating the unserved load.

c. The loading table below shows that at the time of the study, the Nasonville transformer supplied a total of 29.9 megawatts between the four Nasonville feeders in 2018 and was projected to supply a total of 32 megawatts in 2023. Because Nasonville Substation serves the furthest Northwest corner of Rhode Island, only two feeders ties from Woonsocket substation to the east are available to pick up the Nasonville load in the event of losing the Nasonville transformer. The loading table also shows the 2023 projected contingency load-at-risk projections at the time of the study.

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(a)	(b)	(c)	(d)	(e)	(f)
Substation	Transf.	2018 Actual Loads		2023 Projections	
		MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW
Nasonville	T271	400	15.8	446	17.7

d. The Nasonville transformer supplied a total of 32.5 megawatts between the four Nasonville feeders in 2023. This exceeds the Nasonville transformer's study projected load of 32 megawatts by 0.5 megawatts. The 2023 weather adjusted value is 35.2 megawatts. This exceeds the Nasonville transformer's projected load of 32 megawatts by 3.2 megawatts.

e. The table below shows the contingency load-at-risk for 2023 actual and weather adjusted values. Since the distribution planning criteria threshold for unserved load is already exceeded with 2023 actual load, the total unserved load will only increase further in projected future years.

(a)	(b)	(c)	(d)	(e)	(f)
Substation	Transf.	2023 Actual Loads		2023 Weather Adjusted Loads	
		MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW
Nasonville	T271	505	20.2	597	24.1

f. The total contingency unserved load exceeded the Distribution Planning Guidelines when the analysis was performed for the entire study period. The total contingency unserved load is increased further when the analysis is performed with 2023 actual load and weather adjusted 2023 load. The contingency issue has increased in severity since the study.

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g. There have not been any interim projects that have changed load, system capacity or any other factors that would prompt the reevaluation of the proposed project. The period since the study includes the pandemic period which may have affected load levels.

h. The Company is advancing the project in the near term because the contingency issue identified in the study persisted to 2023 and has materialized beyond what was projected.

Langworthy Corner Feeder Ties

a. South County West Area Study, completed December 2021

b. The 86F1 is a heavily loaded feeder out of Langworthy with limited available tie capacity from neighboring circuits. At the time of the study, a loss of the normal supply to the 86F1 resulted in projected unserved load that exceeds the 16 megawatt*hours Distribution Planning Guidelines. The preferred solution is to reconductor 2.8 miles of the 16F1 to increase the summer emergency rating and establish a new feeder tie to the 16F4. The additional tie capacity from the 16F1 and 16F4 addresses the contingency issue.

c. The loading table below shows the contingency load-at-risk at the time of the study for 2020 and 2023. Because Langworthy Corner Substation serves the furthest southwest coast of Rhode Island, only two feeders ties from are available to pick up the 86F1 load in the event of losing the 86F1 normal supply.

(a)	(b)	(c)	(d)	(e)	(f)
Substation	Feeder	2020 Projected Loads		2023 Projected Loads	
		MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW
Langworthy Corner	86F1	28.2	6.1	29.1	6.3

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d. The table below shows the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Substation	**Feeder**	**2020**			**2023**		
		Actual Amps	**Weather Adjusted Amps**	**Study Projected Amps**	**Actual Amps**	**Weather Adjusted Amps**	**Study Projected Amps**
LANGWORTHY 86	86F1	416	478	527	426	461	532
WESTERLY 16	16F1	439	506	492	414	448	497
CHASE HILL 155	155F2	277	319	344	261	283	347

e. The table below shows the contingency load-at-risk for 2023 actual and weather adjusted values and 2024 projected values. Because the distribution planning criteria threshold for unserved load is already exceeded with 2023 weather adjusted value, the total unserved load will only increase further in projected future years.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Substation	Feeder	2023 Actual Loads		2023 Weather Adjusted Loads		2024 Projected Loads	
		MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW
Langworthy Corner	86F1	11.0	1.3	17.0	2.9	17.3	3.0

f. At the time of the South County West Area Study, the 86F1 total unserved load exceeded the Distribution Planning Guidelines when the contingency analysis was performed with 2020 and 2023 projected load. Although weather adjusted loads have decreased versus the study projections, unserved load remains above Distribution Planning Guidelines in 2023 and future projections.

g. There have not been any interim projects that have changed load, system capacity or any other factors that would prompt the reevaluation of the proposed project. The period since the study includes the pandemic period which may have affected load levels.

h. The Company is advancing the project in the near term because the 86F1 total unserved load is projected to exceed the Distribution Planning Guidelines in 2024 and future years.

Prepared by or under the supervision of: Ryan Constable

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Chase Hill 155F8

a. The related area study is the South County West Area Study; completion date is December 2021

b. The 155F8 is a feeder out of Chase Hill Substation that serves 2,195 customers and has its mainline running through 4.7 miles of a difficult to reach rights-of-way (ROW) with small conductors. At the time of the study, the 155F8 had poor reliability, prolonged outages during storm, ROW sections with loading close to the summer normal ratings of the conductor.

c. The loading table below shows that at the time of the study, the 155F8 ROW sections were projected to supply 295A in 2020 and were projected to supply a total of 298A in 2023.

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Substation	Feeder	ROW Conductor Rating (Amps)	Projected Load			
			2020		2023	
			Amps	%SN	Amps	%SN
CHASE HILL 155	155F8	315	295	94%	298	95%

d. The table below shows the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Substation	Feeder	ROW Conductor Rating (Amps)	2020			2023		
			Actual Amps	Weather Adjusted Amps	Projected Amps	Actual Amps	Weather Adjusted Amps	Projected Amps
CHASE HILL 155	155F8	315	259	298	295	222	240	298

e. The following table shows the updated load projections.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Substation	Feeder	ROW Conductor Rating (Amps)	2025		2030		2035	
			Amps	% Rating	Amps	% Rating	Amps	% Rating
CHASE HILL 155	155F8	315	244	77%	245	78%	254	81%

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f. For any project, the Company assesses all factors, not solely loading when determining project prudency. The 155F8 mainline runs through 4.7 miles of a difficult to reach ROW resulting in poor reliability and prolonged outage durations during storm events. The 5-year average circuit frequency and duration reliability metrics of the 155F8 are 2.13 and 176 minutes respectively, exceeding the Company's reliability targets. In addition, approximately 55% of the existing poles on the 155F8 are greater than 30 years of age.

   Regarding loading, the actual loads have remained below the forecasts, as expected. Weather adjusted values are also lower than forecasted, however the ROW section was never predicted to be overloaded.

g. There have not been any interim projects that have changed load, system capacity or any other factors that would prompt the reevaluation of the proposed project. The period since the study includes the pandemic period which may have affected load levels.

h. As described in the South County West Area Study, the 155F8 mainline runs through 4.7 miles of a difficult to reach ROW resulting in poor reliability and prolonged outage durations during storm events. Reliability and asset issues are described above in Part f. The Company is advancing the project in the near term because the 155F8 reliability and asset issues persist and are directly related to the difficult to access ROW sections.

South County East (SCE) Common Solutions

a. The related area study is the South County East Area Study; completion date is in March of 2018.

b. The primary issues identified during the South County East study include asset condition issues on the subtransmission system, contingency load at risk (5 feeders and 1 transformer), and normal loading (3 feeders over summer normal ratings). The asset conditions issues are addressed by the New Lafayette substation described above. A set of common solutions, along with the new Lafayette substation, would provide additional system capacity for contingencies. The Common Solution projects are:
   - Lafayette 30F2 Feeder Tie
   - Lafayette 30F2 Feeder Upgrade
   - Peacedale 59F3
   - Wakefield 17F2
   - Wakefield 17F3
   - Kenyon 68F5

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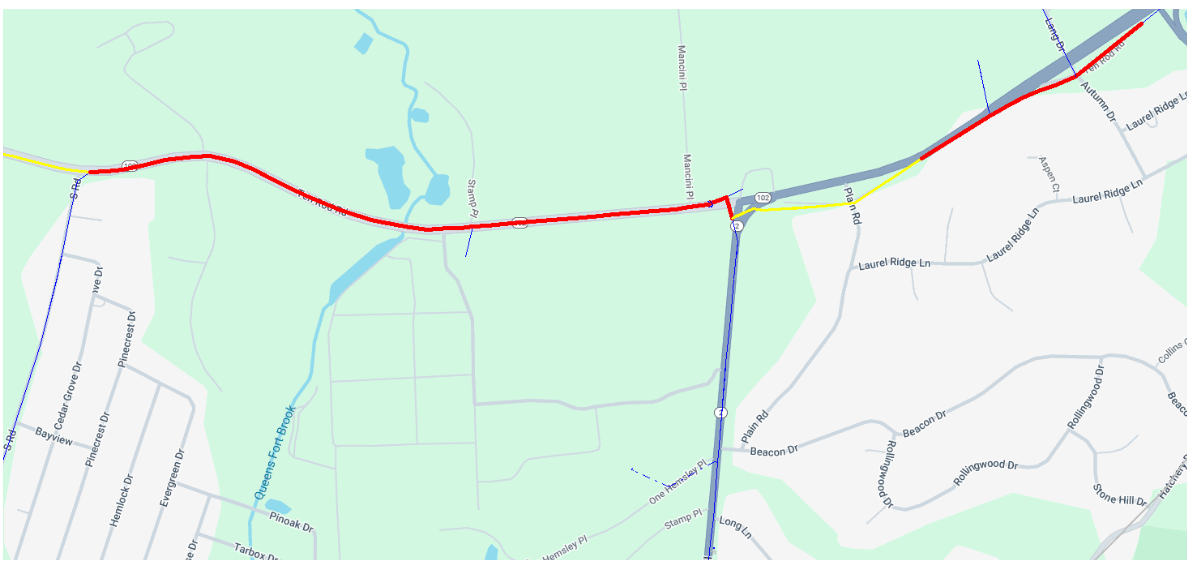
c. Please see Part c., of the New Lafayette project to see capacity ratings and projections at the time of the study.

d. See Attachment DIV 1-30-2_SCE for information showing the actual loads occurring since the time of the Area Study in comparison to projections. Additionally for a more appropriate evaluation, weather adjusted actual values are shown and compared to projections.

e. Please see subpart e., of the response for the New Lafayette project for normal loading and contingency load-at-risk based on current and updated load projections. There is also a section of the 30F2 with loading issues, as shown in the figure below.

30F2 – Ten Rod Road Loading, 2024



f. For any project, the Company assesses all factors, not solely loading when determining project prudency. Aside from the asset condition issues addressed by the New Lafayette Substation project, the South County East Study identified several persistent system loading and contingency issues that require attention.

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Regarding loading, the actual loads have remained below the forecasts, as expected. Weather adjusted values are lower than forecasted for most circuits and higher than forecasted for some circuits, with the overall area weather adjusted loading lower than forecasted. The loading issue on 30F2 at Ten Rod Road remains as a result of area spot loads. Subpart e., of the New Lafayette summary above shows that contingency issues persist for four circuits.

g. As noted above in the response for the New Lafayette project, a fourth feeder out of Quonset Substation was added from the time of the study completion to today, which resulted in shifting of load, especially on the Old Baptist 46F4 circuit. Additional spot load increases on the Quonset, Wakefield, and Lafayette Substations also have caused increases in feeder utilization and reduction in available capacity during contingency load-at-risk situations. The period since the study includes the pandemic period which may have affected load levels.

h. As originally outlined in the South County East Area Study, the distribution system in the area is highly utilized with numerous loading, contingency, and asset issues. The projects outlined in the Study, the common projects as well as the new Lafayette Substation, continue to be required in the near term. These projects, as a comprehensive plan, will provide both normal and the contingency capacity relief to the area and will allow the Company to retire equipment with asset conditions and operational issues as described in subpart f., above.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)
			2015			2016			2017			2018			2019			2020			2021			2022			2023			2024		
	Feeder	SN	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection
1	4F1	515	261	302	325	376	411	329	265	304	330	361	390	331	357	397	332	415	437	334	392	418	335	390	411	336	350	379	338	376	411	339
2	4F2	510	360	417	461	428	468	466	323	371	468	426	460	470	469	521	471	450	475	473	464	496	475	440	463	477	395	428	479	406	444	481
3	51F1	645	417	483	505	467	511	512	376	432	514	455	491	515	455	505	517	438	462	519	413	441	521	421	443	523	403	436	525	365	399	527
4	51F2	530	422	489	468	467	511	474	400	460	476	465	503	477	456	506	479	449	474	481	449	480	483	427	450	485	439	475	487	432	472	488
5	51F3	502	351	407	419	352	385	425	326	375	427	382	413	428	371	411	429	324	342	431	332	355	433	364	383	434	335	363	436	335	366	438
6	20F1	425	302	350	318	309	338	322	285	327	323	289	312	324	284	315	325	263	278	327	271	290	328	313	330	329	260	282	331	264	288	332
7	20F2	425	278	322	377	294	322	382	284	326	383	309	334	384	225	250	385	330	348	387	344	367	388	325	342	390	274	297	392	267	292	393
8	48F1	502	370	428	462	411	450	468	369	424	470	423	457	472	434	482	473	541	570	475	476	508	477	470	495	479	421	456	481	432	472	483
9	48F2	515	372	431	421	392	429	427	370	425	429	370	400	430	372	413	431	365	385	433	332	354	435	360	379	436	360	390	438	312	341	440
10	48F3	510	412	477	543	464	508	550	432	496	552	449	485	554	374	415	556	389	410	558	413	442	560	400	421	562	424	459	564	360	393	567
11	48F4	530	450	521	526	451	493	533	425	489	535	454	491	537	434	482	538	426	450	541	403	431	543	430	453	545	382	414	547	375	410	549
12	48F5	485	382	443	436	553	605	442	423	486	444	364	393	445	335	372	446	316	334	448	337	360	450	404	425	452	393	426	453	393	430	455
13	48F6	530	368	426	398	409	447	403	347	399	405	377	407	406	347	385	407	302	318	409	302	322	410	430	453	412	398	431	414	437	478	415
14	5F1	425	307	355	382	377	412	386	303	348	388	340	367	389	375	416	390	373	394	392	351	375	393	350	369	395	335	363	397	347	379	398
15	5F2	434	335	388	399	355	388	404	335	385	406	365	394	407	319	354	408	369	389	410	346	370	412	398	419	413	330	357	415	334	365	417
16	5F3	530	332	384	396	356	389	401	335	385	403	349	377	404	346	384	405	366	386	407	351	375	408	327	344	410	302	327	412	310	339	413
17	5F4	510	341	395	469	409	447	476	357	410	477	396	427	479	409	454	480	417	440	482	421	449	484	400	421	486	427	462	488	413	451	490
18	78F3	409	208	241	249	264	289	253	196	225	254	216	233	254	215	239	255	168	177	256	236	252	257	248	261	258	308	334	259	344	376	260
19	78F4	409	200	232	235	245	268	238	199	228	239	210	227	239	189	210	240	156	165	241	192	205	242	186	196	243	237	257	244	256	279	245
20	47J2	408	244	283	318	264	289	322	230	264	324	326	352	325	272	302	326	275	290	327	284	303	328	248	261	330	159	172	331	300	328	332
21	47J3	408	232	269	331	308	337	335	247	283	336	312	337	337	304	338	338	312	329	340	292	312	341	300	316	343	224	243	344	272	297	345
22	47J4	408	324	375	361	332	363	366	252	289	367	296	319	369	288	320	370	296	313	371	276	295	373	305	321	374	256	277	376	280	306	377

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
			2017			2018			2019			2020			2021			2022			2023			2024		
	Feeder	SN	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection
1	42F1	525	392	450	517	431	465	515	483	536	516	417	440	517	431	460	519	437	460	522	402	435	525	390	426	529
2	30F1	350	204	234	262	250	270	261	219	243	261	225	237	262	225	240	263	227	239	265	254	275	266	261	285	268
3	30F2	530	345	396	459	373	403	457	387	430	458	282	298	459	378	404	461	364	383	464	270	292	467	275	301	469
4	46F1	530	345	396	423	382	413	422	369	410	422	385	406	423	350	374	425	357	376	427	303	328	430	305	333	433
5	46F2	530	276	317	377	277	299	376	314	349	376	302	319	377	288	308	379	291	306	381	251	272	383	268	293	386
6	46F3	565	309	355	364	346	374	362	314	349	363	331	349	364	313	334	365	316	333	368	297	322	370	310	339	372
7	46F4	594	457	525	527	492	531	476	498	553	476	292	308	477	274	293	479	329	346	482	274	297	485	286	313	488
8	59F1	409	134	154	165	142	153	165	149	165	165	147	155	165	147	157	166	147	155	167	135	146	168	155	169	169
9	59F2	492	263	302	327	285	308	326	287	319	327	290	306	327	272	290	329	280	295	331	260	282	333	276	302	335
10	59F3	492	372	427	479	426	460	478	457	507	478	421	444	479	418	446	481	414	436	484	389	421	487	395	432	490
11	59F4	425	159	183	191	193	208	190	190	211	190	179	189	191	159	170	192	171	180	193	167	181	194	162	177	195
12	83F1	555	126	145	165	126	136	115	114	127	170	106	112	246	110	117	337	113	119	339	135	146	341	139	152	343
13	83F2	555	304	349	304	288	311	151	286	317	151	342	361	226	355	379	227	373	393	229	356	386	230	376	411	287
14	83F3	515	280	322	330	280	302	329	280	311	330	259	273	330	269	287	332	276	291	334	277	300	336	283	309	338
15	83F4	515	0	0	0	265	286	252	277	307	252	240	253	253	241	257	254	252	265	256	229	248	257	240	262	259
16	17F1	602	387	445	509	403	435	471	487	541	471	418	441	472	408	436	475	429	452	478	434	470	481	395	432	483
17	17F2	510	425	488	489	456	492	508	432	480	508	432	456	509	451	482	512	465	490	515	457	495	518	432	472	521
18	17F3	597	417	479	384	447	483	487	371	412	488	423	446	489	468	500	491	433	456	494	417	452	497	423	462	500
19	88F1	530	349	401	444	377	407	383	394	437	383	378	399	384	381	407	386	404	425	388	397	430	391	342	374	393
20	88F3	550	358	411	411	371	401	443	378	420	444	377	398	444	378	404	447	378	398	449	403	436	452	360	393	455
21	88F5	530	350	402	405	368	397	410	343	381	411	361	381	411	380	406	413	369	389	416	325	352	418	349	381	421
22	88F7	530	318	365	336	351	379	404	277	307	405	326	344	405	345	368	408	343	361	410	335	363	412	329	360	415

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			2021			2022			2023			2024		
	Feeder	SN	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection
1	64F1	361	230	246	197	227	239	198	206	223	199	201	220	200
2	64F2	361	171	183	160	236	248	161	126	136	162	122	133	163
3	54F1	526	413	441	487	402	424	490	360	390	492	377	412	494
4	61F1	450	321	343	364	346	364	366	312	338	368	297	325	370
5	61F2	450	288	308	331	294	310	333	280	303	335	306	334	336
6	61F3	450	375	401	376	355	374	379	349	378	380	332	363	382
7	61F4	450	329	351	371	327	345	373	318	345	375	354	387	377
8	15F1	348	157	168	202	153	161	203	142	153	204	212	232	205
9	15F2	515	398	425	461	380	400	464	352	381	466	375	410	468
10	63F1	538	224	239	237	246	259	239	257	279	240	296	324	241
11	63F2	530	298	318	384	302	318	386	269	292	388	288	315	390
12	63F3	530	304	325	311	295	311	313	274	297	314	264	289	316
13	63F4	530	356	380	411	366	385	414	330	357	416	351	384	418
14	63F5	530	292	312	309	299	315	311	281	304	313	280	306	314
15	63F6	530	483	516	541	459	483	545	409	443	547	414	453	549
16	22F1	530	359	383	383	352	371	385	319	346	387	327	357	388
17	22F2	530	401	428	440	397	418	443	346	375	445	372	407	447
18	22F3	530	228	244	296	226	238	297	202	218	299	195	213	300
19	22F4	586	276	295	299	284	299	300	254	275	302	252	275	303
20	22F6	510	355	379	397	359	378	400	337	365	402	337	368	403
21	29F1	385	318	340	356	311	327	358	282	306	359	312	341	361
22	29F2	409	248	265	290	260	274	292	250	271	294	213	233	295
23	28F1	390	104	111	156	118	125	157	110	119	157	105	115	158
24	28F2	390	81	87	116	82	87	116	76	83	117	64	70	118
25	100F1	570	446	476	463	449	473	466	394	427	469	395	432	470
26	150F2	535	244	261	358	247	260	360	212	230	362	209	228	363
27	150F4	530	292	312	341	308	324	343	249	269	345	269	294	347
28	150F6	535	406	434	450	398	419	452	376	407	455	174	190	456
29	150F8	535	259	277	284	261	275	286	272	294	288	453	495	289

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
			2020			2021			2022			2023			2024		
	Feeder	SN	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection	Actual	Actual Weather Adjusted	Study Projection
1	68F1	512	338	356	380	290	310	379	357	376	381	324	351	383	324	355	385
2	68F2	511	431	455	552	445	475	551	464	489	554	458	496	557	433	473	559
3	68F3	512	412	434	438	373	398	437	376	396	440	341	369	442	368	402	444
4	68F4	514	304	321	471	370	395	470	397	418	473	403	437	476	378	413	477
5	68F5	612	165	174	218	165	176	217	147	155	219	148	160	220	141	154	220
6	86F1	600	416	439	527	442	472	526	455	479	529	426	461	532	421	460	534
7	16F1	515	439	463	492	411	439	491	429	451	494	414	448	497	407	445	499
8	16F2	515	214	226	423	205	219	422	201	212	424	191	207	426	190	207	428
9	16F3	515	366	386	390	340	363	390	351	370	392	309	335	394	336	368	395
10	16F4	645	347	366	377	358	382	377	361	380	379	314	340	381	315	344	382
11	155F2	530	277	292	344	277	296	343	286	301	345	261	283	347	252	275	348
12	155F4	530	225	237	244	223	238	244	241	254	245	191	207	247	194	212	248
13	155F6	530	267	282	286	349	373	285	409	431	287	411	445	289	408	446	290
14	155F8	530	287	303	327	267	285	327	269	283	328	246	266	330	244	267	331

Division 1-31

System Capacity & Performance

Request:

What is the Company's justification for increasing the CEMI-4 budget to $2.15 million from the previously Commission approved level of $1.23 million?

Response:

The Company's increase of the CEMI-4 budget is due to the inclusion of reclosers in this year's program proposal.

The Company originally presented a $1.2 million CEMI-4 budget during the FY 2024 Electric ISR Plan filing. To simplify communications on reclosers, and to be clear there was no double counting, the Company explained during that proceeding that all reclosers were included in the Advanced Recloser and the Mainline Recloser Enhancement programs, even if a recloser was needed for the CEMI program. When the proposals mentioned above were rejected, the reclosers needed to achieve the CEMI program goals were deferred.

Within the FY 2025 ISR Plan, the Company submitted CEMI Program documentation that stated, "Six sample locations were reviewed to estimate annual project costs…The estimated capital cost of all projects for the sample locations is $ 2.6 M." This included costs for reclosers associated with those projects. The $2.15 million is the cost to address the highest priority CEMI circuits, which includes a yearly level of interruption of seven or more with at least 500 customers.

Division 1-32
System Capacity & Performance

Request:

In executable format, please update all reliability and CEMI quartile results (requested in FY 2025 ISR Plan, DIV 3-16) to include 2023. For DIV 3-16 d, highlight the quartile achieved by RIE for each year. Add a worksheet with underlying data and calculations corresponding to the information in Attachment 4 – Chart 3.

Response:

Please see the Excel version of Attachment DIV 1-32 for an update of all reliability and CEMI quartile results originally provided in the Company's response to Division 3-16 in Docket No. 23-48-EL regarding the FY 2025 ISR Plan, including 2023.

In preparing this response, the Company discovered an error in the original data used for the response to Division 3-16 in Docket No. 23-48-EL. This error related to the data for CEMI analysis without major storms, which the Company does not use, but which is included to be responsive to the Division's request. The Excel file tab labeled "DIV 3-16 c" in Attachment DIV 1-32 contains the update to the Company's original response to Division 3-16 c. The corrected calculation is N or more, where N indicates the minimum number of outages seen by the customers. For example, if N = 3, the calculation is for customers who experienced 3 or more events. This method was used for Major Storm Included values and aligned with the IEEE 1366 calculation method, which is used for the EEI evaluation. The corrected values are highlighted in yellow.

The updated quartile results with and without major storms for each year are highlighted in the tab labeled "DIV 3-16 d" in Attachment DIV 1-32. Green highlights indicate the specific year's performance. The blue highlights show the 5-year average compared to 2023 quartile levels.

Also, the error discovered in the CEMI values in the original response to Division 3-16 c in Docket No. 23-48-EL also impacted the values in Attachment 4 – Chart 3 in the FY 2026 ISR Plan. The Company is including an updated Attachment 4 – Chart 3 with the worksheet on tab "DIV 3-16 d" of Attachment DIV 1-32, which ties to the underlying data and calculations on that tab.

Prepared by or under the supervision of: Ryan Constable

Attachment DIV 1-32

As requested by the Division, the Company is providing its Excel version of Attachment DIV 1-32

Prepared by or under the supervision of: Ryan Constable

Division 1-33

System Capacity & Performance

Request:

When will the Company produce a CEMI-4 benefit-cost analysis based on actual costs and performance for stakeholder review to determine the effectiveness and need to continue investments?

Response:

The Company does not recommend completing a CEMI-4 benefit-cost analysis based on actual costs and performance until a sufficient number of years have passed. A reasonable period is five years; however, the Company is receptive to providing information after at least three years. The earliest this can be done is the middle of 2027 or early 2028.

Division 1-34

System Capacity & Performance

Request:

Is the Distribution Automation Recloser Program (DARP) the same program proposed by RIE in the FY 2025 ISR Plan? If not, please explain the key differences. If so, what is the Company's justification for again proposing DARP given that the Commission denied the creation of a new Distribution Automation Recloser Program in the ISR Plan FY 2025 Proposal Decision?

Response:

The Distribution Automation Recloser Program (DARP) is the same program proposed by Rhode Island Energy in the FY 2025 ISR Plan. Although there are no key differences between the substance of the investments in the plans, there are differences in the cash flow. The Company maintains the same justification it presented in previous years: individual circuit reliability analysis demonstrates unacceptable performance on a subset of circuits. The Company understands the Commission's denial of the recloser program to have two main components. First, that this work can be incorporated into Rhode Island Energy's normal course of business. Second, that the Division required additional data, termed recloser memos, to determine the appropriateness of investment.

The Company has and does incorporate advanced devices into its normal course of business; however, there are still near-term circuit outage frequency and duration issues that are problematic. Therefore, Rhode Island Energy has proposed the Distribution Automation Recloser Program (DARP) because of the existing need and intends to provide the recloser memos for the specific installations it is planning to complete as part of the FY 2026 ISR Plan during this proceeding. The Company is not seeking pre-approval of all on-going investments as part of the DARP that would occur beyond the FY 2026 ISR Plan in this docket.

Prepared by or under the supervision of: Ryan Constable

Division 1-35
System Capacity & Performance

Request:

In executable format, provide the Projected Summer Normal Feeder Loading (Table 4.1.1, East Bay Area Study dated August 2015). Add the following additional loading data: 2015 actual loads, 2024 actual loads, and projections for 2030 and 2035. Highlight any violations.

Response:

Please see Attachment DIV 1-35 for the information requested in executable format. There are no identified violations. Six highly-loaded circuits are highlighted in yellow.

Prepared by or under the supervision of: Ryan Constable

Attachement DIV-35

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(1)	Substation	Feeder	SN Rating	2015 (Actuals)		2024 (Actuals)		2025 Projection		2030 Projection		2035 Projection	
(2) (3)				Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN	Amps	%SN
(4)	BARRINGTON 4	4F1	515	261	51%	376	73%	411	80%	401	78%	404	78%
(5)	BARRINGTON 4	4F2	510	360	71%	406	80%	444	87%	433	85%	437	86%
(6)	BRISTOL 51A	51F1	645	417	65%	365	57%	399	62%	389	60%	392	61%
(7)	BRISTOL 51A	51F2	530	417	79%	432	82%	472	89%	461	87%	465	88%
(8)	BRISTOL 51A	51F3	502	351	70%	335	67%	366	73%	357	71%	360	72%
(9)	WAMPANOAG 48	48F1	502	370	74%	432	86%	472	94%	461	92%	464	93%
(10)	WAMPANOAG 48	48F2	515	372	72%	312	61%	341	66%	333	65%	335	65%
(11)	WAMPANOAG 48	48F3	510	412	81%	360	71%	393	77%	384	75%	387	76%
(12)	WAMPANOAG 48	48F4	530	450	85%	375	71%	410	77%	400	75%	403	76%
(13)	WAMPANOAG 48	48F5	530	382	72%	393	74%	430	81%	419	79%	423	80%
(14)	WAMPANOAG 48	48F6	530	368	69%	358	68%	391	74%	382	72%	385	73%
(15)	WARREN 5	5F1	425	307	72%	347	82%	379	89%	370	87%	373	88%
(16)	WARREN 5	5F2	434	335	77%	308	71%	337	78%	329	76%	331	76%
(17)	WARREN 5	5F3	515	332	64%	310	60%	339	66%	331	64%	333	65%
(18)	WARREN 5	5F4	510	341	67%	413	81%	451	89%	441	86%	444	87%
(19)	OUT OF PHASE FEEDERS												
(20)	PHILLIPSDALE 20	20F1	425	302	71%	264	62%	288	68%	281	66%	283	67%
(21)	PHILLIPSDALE 20	20F2	425	278	65%	267	63%	292	69%	285	67%	287	68%
(22)	WATERMAN AVENUE 78	78F3	409	208	51%	344	84%	376	92%	367	90%	370	90%
(23)	WATERMAN AVENUE 78	78F4	409	200	49%	256	63%	279	68%	273	67%	275	67%
(24)	4.16 kV POCKET OF LOAD												
(25)	KENT CORNERS 47	47J2	408	244	60%	300	74%	328	80%	320	78%	323	79%
(26)	KENT CORNERS 47	47J3	408	232	57%	272	67%	297	73%	290	71%	292	72%
(27)	KENT CORNERS 47	47J4	408	324	79%	280	69%	306	75%	299	73%	301	74%

Division 1-36

System Capacity & Performance

Request:

In executable format, provide the Calculated MWH exposure (Table 4.1.2, East Bay Area Study dated August 2015). Add calculations based on 2015 actual loads, 2024 actual loads, and projections for 2030 and 2035. Highlight any violations.

Response:

Please see Attachment DIV 1-36 for the information requested in executable format. Circuits with load-at-risk greater than 16 MWh are highlighted in red.

Attachement DIV-36

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(1)	Substation	Feeder	2015 Actual Loads		2024 Actual Loads		2025 Projections		2030 Projections		2035 Projections	
(2)(3)			MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW	MWh Exposure	Un-Served MW
(4)	BARRINGTON 4	4F1	4.2	0.0	6.1	0.0	15.7	2.3	8.7	0.6	9.6	0.9
(5)	BARRINGTON 4	4F2	6.6	0.2	16.3	2.4	24.5	4.3	18.0	2.9	18.8	3.0
(6)	BRISTOL 51A	51F1	6.7	0.0	5.9	0.0	6.5	0.0	6.3	0.0	6.4	0.0
(7)	BRISTOL 51A	51F2	14.0	1.8	11.1	1.0	19.4	3.0	17.1	2.4	17.9	2.6
(8)	BRISTOL 51A	51F3	5.7	0.0	5.4	0.0	7.0	0.3	5.8	0.0	5.8	0.0
(9)	WAMPANOAG 48	48F1	19.9	3.7	15.2	2.7	19.3	3.7	18.1	3.4	18.5	3.5
(10)	WAMPANOAG 48	48F2	4.5	0.0	4.3	0.0	4.7	0.0	4.6	0.0	4.7	0.0
(11)	WAMPANOAG 48	48F3	6.0	0.0	7.0	0.0	16.6	2.2	13.5	1.5	14.5	1.8
(12)	WAMPANOAG 48	48F4	6.8	0.2	5.8	0.2	16.1	2.6	13.2	2.0	14.2	2.2
(13)	WAMPANOAG 48	48F5	6.7	0.0	5.8	0.0	9.2	0.7	6.2	0.0	6.3	0.0
(14)	WAMPANOAG 48	48F6	32.5	6.3	14.2	2.0	22.3	3.9	20.0	3.4	20.8	3.6
(15)	WARREN 5	5F1	6.2	0.0	8.8	0.6	20.0	3.3	16.8	2.5	17.9	2.8
(16)	WARREN 5	5F2	12.6	1.7	12.6	1.4	23.6	4.0	20.5	3.2	21.5	3.5
(17)	WARREN 5	5F3	5.0	0.0	13.6	2.0	24.1	4.5	11.3	1.3	12.3	1.6
(18)	WARREN 5	5F4	11.5	1.5	9.2	0.9	16.7	2.7	8.0	0.6	8.7	0.7
(19)	PHILLIPSDALE 20	20F1	5.4	0.0	5.0	0.0	5.5	0.0	5.4	0.0	5.4	0.0
(20)	PHILLIPSDALE 20	20F2	5.5	0.0	6.7	0.0	7.3	0.0	7.1	0.0	7.2	0.0
(21)	WATERMAN AVENUE 78	78F3	3.4	0.0	8.3	0.7	14.7	2.2	12.9	1.7	13.5	1.9
(22)	WATERMAN AVENUE 78	78F4	3.2	0.0	5.0	0.2	11.1	1.6	9.4	1.2	9.9	1.4

Division 1-37

System Capacity & Performance

Request:

Explain any material changes affecting load or reliability in the East Bay area since the study was completed in 2015. What investments, if any, were required to address system impacts arising from these changes?

Response:

The only change that has occurred affecting net load levels is the penetration of the new distributed generation in the area. No significant changes in reliability have occurred since the study was completed. No investments were required to address system impacts because of the effects on net load levels from the penetration of new distributed generation in the area.

Prepared by or under the supervision of: Ryan Constable

Division 1-38
System Capacity & Performance

Request:

Provide a list of major equipment required for Phillipsdale substation, dates ordered (or to be ordered), scheduled delivery (or anticipated delivery), and cost.

Response:

The Company considers major equipment to be equipment that is forecasted to individually cost more than $50,000. This project is in the design stage. The Company has not procured any major equipment yet.

For definitions, the Order Date is when the Purchase Order was sent out to the awarded Supplier, and the Delivery Date is when the equipment is expected to arrive. The procurement process, including necessary Request for Proposal (RFP) cycles and negotiation occurs before the Order Date.

Please see the table below for a list of the major equipment required for the Phillipsdale Substation. The Company will be publishing the Transformer Request for Proposal package to suppliers in mid-November 2024.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Transformer	1	Planned March 31, 2025	September 30, 2027	$ 2,500,000.00
2	Metalclad Switchgear Power Control Center	1	Planned September 30, 2025	September 30, 2027	$ 2,000,000.00
3	Capacitor Bank	1	Planned September 30, 2025	September 30, 2026	$ 325,000.00

Prepared by or under the supervision of: Daniel Glenning

Division 1-39

System Capacity & Performance

Request:

The East Bay Area Study states (page 31):

> "The Phillipsdale 115/23kV substation has numerous asset condition concerns which are being deferred. Loading on the 23kV station will be reduced to approximately 3MW and the station will supply only two industrial customers. It is recommended that this area be reviewed in the next few years and consideration be given to fully retire Phillipsdale 23kV station in lieu of performing any major asset replacement work."
>
> What is the outcome of the Company's review and consideration of fully retiring Phillipsdale 23kV?

Response:

The Company's latest long term plan includes the retirement of the Phillipsdale 23kV station. The work associated with this retirement is part of the Phillipsdale Substation project in the FY 2026 Plan.

The original scope in the East Bay Area Study retained the 23kV yard at Phillipsdale Station. However, in 2020, the Company re-evaluated this need and determined that the 23kV yard should be retired due to significant asset condition issues. As a result, the Company decided to retire all 23kV assets at this station and transfer the remaining load to the new 12.47kV station at the same location.

Division 1-40

System Capacity & Performance

Request:

Does the proposed Phillipsdale Major Project substation work resolve projected overloads and MWh exposure, if any, at both Phillipsdale and Wampanoag? If not, explain additional work required.

Response:

The Phillipsdale Substation Project, along with the East Providence Substation and Warren Expansion Projects, are part of a comprehensive plan. This plan was identified in the East Bay Study and addresses asset condition, loading and MWh load-at-risk issues in the study area, including at Phillipsdale and Wampanoag. No work outside of these projects will be required to address the issues.

Prepared by or under the supervision of: Ryan Constable

Division 1-41
System Capacity & Performance

Request:

Provide the scope of work planned for East Providence distribution lines in FY 2025, FY 2026 and FY 2027 totaling $9.4 million.

Response:

From FY 2025-FY 2027, the scope of work for the East Providence distribution line project includes engineering, design and construction of all required distribution (overhead and underground) upgrades and conversion work to support the new 12kV substation at First Street.

The distribution project scope consists of:

- Upgrading feeders in the area to facilitate the construction of 4 new feeders out of First Street East Providence substation – 2F1, 2F2, 2F3, and 2F4. During FY 2026, there will also be underground construction to install new manholes and duct systems to support feeders, 2F1, 2F2, 2F3, and 2F4 coming out from the substation to Mauran Ave.
- Rerouting portions of the Wampanoag Ave feeders to serve areas of Barrington and East Providence.
- Retiring most of the 23 kV infrastructure, including the retirement of Waterman Ave substation and its feeders.
- Retiring Kent Corner substation (4 kV) and converting the existing load to 12 kV.

Some of the distribution upgrades and conversion work may be done in advance of the substation construction or in parallel to substation construction to be ready for cutover when the substation is fully constructed. There is a portion of the conversion work (including remote settings) that must be completed after the new substation is energized.

Prepared by or under the supervision of: Daniel Glenning

Division 1-42
System Capacity & Performance

Request:

Provide a list of major equipment required for East Providence substation, dates ordered (or to be ordered), scheduled delivery (or anticipated delivery), and cost.

Response:

The Company considers major equipment to be equipment that is forecasted to individually cost more than $50,000. Please see the table below for a list of the major equipment required for the East Providence First Street Substation.

For definitions, the Order Date is when the Purchase Order was sent out to the awarded Supplier, and the Delivery Date is when the equipment is expected to arrive. The procurement process, including necessary Request for Proposal (RFP) cycles and negotiation, occurs before the Order Date.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Transformer	1	9/12/2023	June 30, 2026	$ 2,262,600.00
2	Metalclad Switchgear Power Control Center	1	6/24/2024*	June 30, 2026	$ 2,643,345.00
3	Capacitor Bank	1	12/16/2023	June 30, 2026	$ 327,379.20

**The procurement process for this Switchgear began in August 2023 and took longer than anticipated. At the time of RFP Publication, Suppliers were still recovering from pandemic related labor and material shortages and backups in their quotations department. The RFP cycle was elongated due to requests for extension for original bids and to a slow response time from Suppliers to all subsequent Company clarifications and negotiations.*

Prepared by or under the supervision of: Daniel Glenning

Division 1-43

System Capacity & Performance

Request:

Please provide a summary and status of the Company's East Bay Area Study recommendations as follows:

a. For completed projects, indicate construction start and completion dates, original Area Study cost estimate, actual cost, and material scope changes between the original recommendation and implemented projects.

b. For pending projects, Area Study cost estimate, current cost estimate status and amount, expected construction start, anticipated completion dates and material scope changes between the original recommendation and proposed project.

Response:

a. For the East Bay Area Study, no projects have been completed.

b. For pending projects, see the information below.

Division 1-43, page 2

System Capacity & Performance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Project	**Area Study Estimate ($M)**	**Area Study Estimate Adjusted for Inflation ($M)**	**Current Estimate ($M)**	**Estimate Status**	**Construction Start Date**	**Projected Completion Date**
1	Warren Expansion (D-Sub)	3.42	5.85	6.92	Preliminary Engineering Estimate	5/1/2025	3/31/2026
2	Warren Expansion (D-Line)	3.70	6.83	8.07	Preliminary Engineering Estimate	10/1/2025	4/30/2026
3	East Providence Sub (D-Sub)	6.60	11.29	19.67	Preliminary Engineering Estimate	5/1/2025	3/31/2026
4	East Providence Sub (D-Line)	7.37	13.61	9.39	Preliminary Engineering Estimate	11/1/2025	11/1/2026
5	Phillipsdale (D-Sub)	6.02	10.29	19.93	Preliminary Engineering Estimate	6/1/2026	9/1/2026
6	Phillipsdale (D-Line)	3.72	6.86	3.23	Preliminary Engineering Estimate	6/1/2026	9/1/2026
7	Bristol Fourth Feeder (D-Line & D-Sub)	1.2	2.22	2.027	Preliminary Engineering Estimate	4/1/2025	3/31/2027

Prepared by or under the supervision of: Ryan Constable

System Capacity & Performance

Scope Changes:

Warren Expansion D-Line

There have been changes to the distribution scope of the Warren Expansion Project. The original scope involves three circuits crossing the Palmer River: one underground and two overhead utilizing the existing infrastructure. The overhead crossing was determined infeasible due to structure size and guying requirements, proximity to the water, and community concerns. As a result, the Company changed the scope to install all three circuits underground and attached to the Warren Bike Path Bridge. This bridge, under design by RIDOT, is expected to be in service within the project timeline. Substantial negotiations have taken place between the Company and government agencies to coordinate this electric distribution project with the bridge project.

Warren Expansion D-Sub

The Warren Expansion Substation scope, as outlined in the East Bay Study, includes the addition of two new distribution circuits and the installation of new capacitor banks within the Warren Substation. As part of a separate initiative, the Company identified the need to replace the 23kV circuit breakers at Warren Station. There are some overlaps in civil construction and outage requirements between both projects. The Company merged these two projects to enhance efficiency and facilitate execution.

East Providence Substation D-Sub

There are no significant changes to the original scope for this project, however, there have been significant negotiations between the Company and different entities regarding real estate and permitting issues that have impacted total project costs.

Phillipsdale D-Line

The original scope from the area study proposed retaining the 23kV yard at the Phillipsdale Station, with customers served by the two circuits operating at 23kV. The revised scope proposes the retirement of the 23kV yard and conversion of all 23kV customers to 12.47kV. Also see the Company's response to Division 1-39.

Division 1-43, page 4
System Capacity & Performance

Phillipsdale D-Sub

The original scope retained the 23kV yard at Phillipsdale Station; however, in 2020, the Company re-evaluated this need and determined that the 23kV yard should be retired due to significant asset condition issues. As a result, the company decided to retire all 23kV assets at this station and transfer the remaining load to the new 12.47kV station at the same location. Also see the Company's response to Division 1-39.

Division 1-44
System Capacity & Performance

Request:

The East Bay Area Study recommends upgrading the thermal capability of 5F2 and 5F4 feeders in Warren substation and also expanding Warren to address asset and safety concerns at Barrington substation, eliminate the need for a new Mink Street Substation, and eliminate the need for major upgrades on the 23kV supply system. What projects in the ISR Plan are specifically associated with the Warrant thermal upgrades versus the additional feeders? Which projects resolve any projected overloads or MWh exposure on existing Warren feeders?

Response:

The work associated with thermal upgrades to the 5F2 and 5F4 feeders is included in the Warren Expansion Project. The Warren Expansion Project, along with the East Providence Substation and Phillipsdale Projects are part of a comprehensive plan. The plan was identified in the East Bay Study to address asset condition, loading and MWh load-at-risk issues in the East Bay area.

Division 1-45

System Capacity & Performance

Request:

Discuss investments associated with Mink Street in Massachusetts that are required as a result of implementing the East Bay Area Study solutions, and any cost responsibilities. Does RIE's change of ownership impact the East Bay recommendations?

Response:

The change of ownership of The Narragansett Electric Company has not changed the recommendations of the East Bay Study.

The transformer that supplies the 2267 circuit into Rhode Island is sourced from the Mink Street Substation located in Seekonk, Massachusetts. National Grid has had a planned project to retire the line and upgrade this transformer for several years. That retirement has been delayed at the request of Rhode Island Energy. The Company has maintained ongoing communication with National Grid to explain the project issues in support of the delay. Once the Company completes the East Bay Area Study projects, it will remove the Rhode Island Energy assets and notify National Grid that its work on the Mink Street Substation can proceed.

Prepared by or under the supervision of: Ryan Constable

Division 1-46

System Capacity & Performance

Request:

Provide a list of major equipment required for Warren, dates ordered (or to be ordered), scheduled delivery (or anticipated delivery), and cost.

Response:

The Company considers the major equipment to be equipment that is forecasted to individually cost more than $50,000. Please see the table below for a list of the major equipment required for the Warren Substation.

For definitions, the Order Date is when the Purchase Order was sent out to the awarded Supplier, and the Delivery Date is when the equipment is expected to arrive. The procurement process, including necessary Request for Proposal (RFP) cycles and negotiation occurs before the Order Date.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Capacitor Banks	2	December 28, 2023	December 30, 2025	$ 654,758.40

Prepared by or under the supervision of: Daniel Glenning

Division 1-47
System Capacity & Performance

Request:

Why is New Lafayette Substation project with a total investment level of $3.4 million included as a separately tracked project? How is this related to the New Lafayette Substation project in the System Capacity & Performance category budgeted at $2.7 million in FY 2026?

Response:

The New Lafayette Substation project, shown on Bates page 54, Attachment 3, Line 14, is included in the Fiscal Year ("FY") 2026 ISR Plan as a Separately Tracked Major Project because it is a multi-year substation project with forecasted capital spending that will exceed $5.0 million. Please see the table below showing actual and forecasted capital spending.

	(a)	(b)	(c)
Line Number	**Capital Spending (time period)**	**Capital Spending ($000s)**	**FY 2026 ISR Plan Reference**
1	Actual Capital Spending through 3/31/24	$4,017	Bates page 54, Line 14, column (p)
2	Forecasted Capital Spending FY 2025	200	Bates page 53, Line 4, column (c) *
3	Forecasted Capital Spending FY 2026	3,454	Bates page 54, Line 14, column (e)
4	Total Capital Spending	$7,671	

*In FY 2025, the New Lafayette Substation project shown on Bates page 53, Line 4, column (c) is made up of two projects, a substation project and a line project totaling $305,000. Forecasts for the individual projects in the FY 2025 Q1 Report are $200,000 for the substation project and $105,000 for the line project.

Due to the delays from transmission outage coordination issues, the Company had not included this project as a Separately Tracked Major Project until the FY 2026 ISR. Prior to the FY 2026 ISR, both the substation project and the line project were included as one line item in the System Capacity & Performance spending rationale – see Bates page 53, Attachment 3, Line 4, column (d).

The New Lafayette Substation project in the System Capacity & Performance category budgeted at $2.7 million in FY 2026 is the distribution line portion of the project only. This is described on Bates page 36, under the ***East Providence Substation, Warren Substation and New Lafayette Substation Distribution Line projects*** bulleted item.

Prepared by or under the supervision of: Daniel Glenning

Division 1-48

System Capacity & Performance

Request:

The New Lafayette substation schedule has been adjusted multiple times in previous years due to transmission outage coordination issues. Generally explain the transmission outage and substation coordination needs. Demonstrate that the Company has firm commitments for the required outage and provide a schedule of substation work showing alignment with the scheduled outage.

Response:

The New Lafayette substation outage requirement is the connection of a tap to the transmission line. The delay was due to transmission outage constraints caused by the Revolution Wind Farm. Due to their aggressive schedule, there were limited, if any, outage windows that could be executed without putting the system at risk or delaying the Revolution Wind project. The Company determined that it could safely delay the energization of the New Lafayette substation and, therefore, adjusted the schedule for the project.

The complexity of the Revolution Wind Farm outage plan was due to the scope of work being completed in a compressed window of time; some of the scope details are:

- The Company's projects:
  - Installation of 12.3 miles of optical ground wire ("OPGW") on the G185S (Davisville Tap to West Kingston Sub) to support the required protection scheme for the Revolution Wind Farm;
  - Rebuild the L190S with 12.5 miles 795 kcmil aluminum conductor steel supported ("ACSS") conductor (Davisville Tap to West Kingston Sub);
  - Rebuild both Davisville tap lines (G185 and L190) with bundled 1590 kcmil aluminum conductor steel reinforced ("ACSR") conductors;
  - Reconductor the Old Baptist taps with 954 kcmil ACSR Cardinal conductor;
  - Rebuild the G185 and L190 mainlines with bundled 954 kcmil bundled ACSR Cardinal conductor from the Davisville tap north to the Kent County substation;
  - Reconductor the K189 with bundled 954 kcmil ACSR Cardinal conductor and the G185N with 795 kcmil ACSR conductor from Kent County substation to Drumrock;
  - Replace five 115kV breakers at Drumrock; and
  - Update remote end protection at Kent County, West Kingston, Wickford Junction, and the existing Davisville substations;

System Capacity & Performance

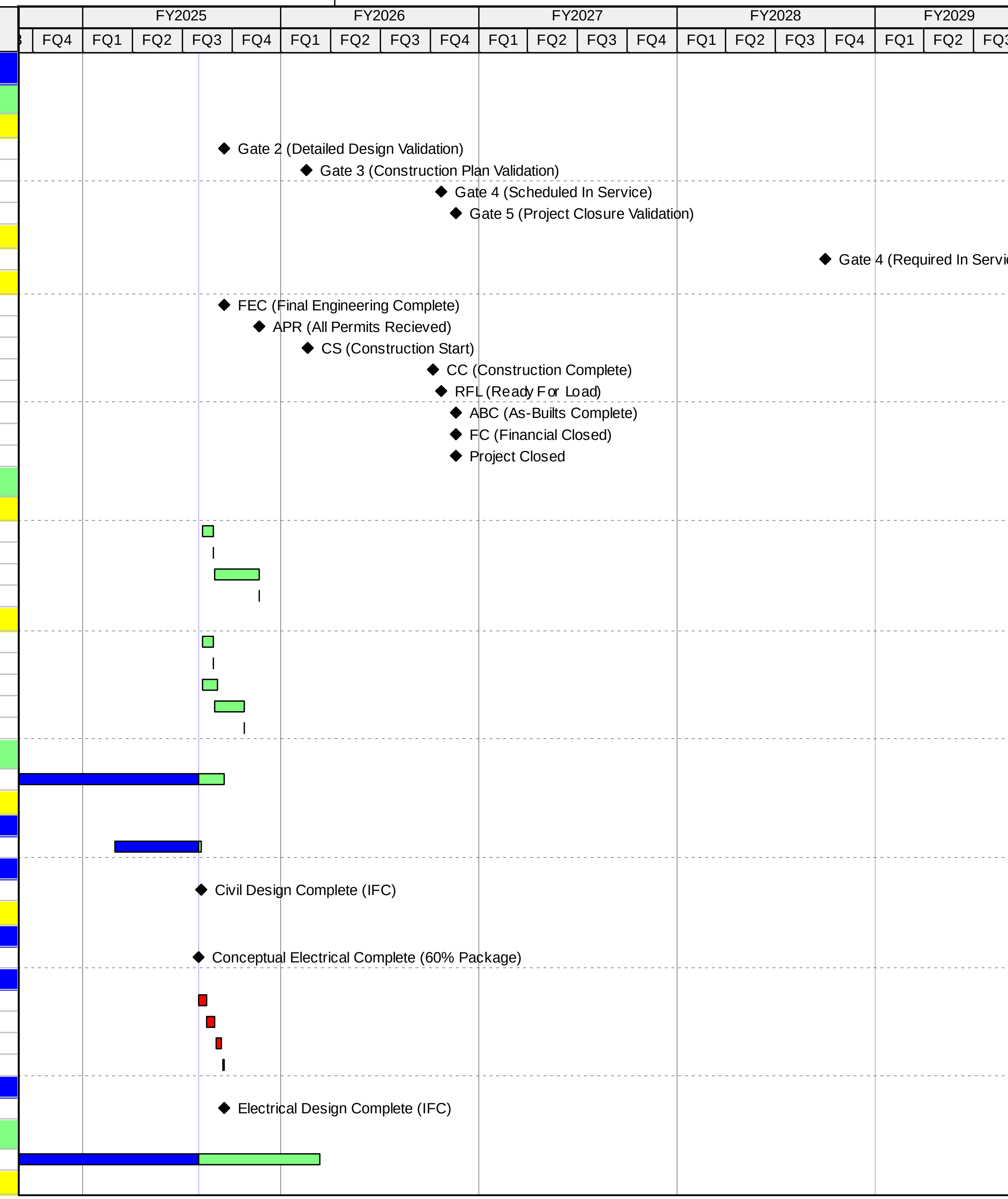
- The Revolution Wind developer's onshore projects:
  - Land based cable installation in the Quonset Point Industrial Park;
  - Construction of developer-owned substation;
  - Expand the Company's Davisville substation to include a new ring-bus and connect to the Developer's substation.

Please see Attachment DIV 1-48 for the current New Lafayette substation project schedule. A final construction sequencing and outage schedule will be developed once a construction contract is awarded. Outage applications will be submitted once the outage schedule is finalized.

Prepared by or under the supervision of: Daniel Glenning

New Lafayette / Wickford Junction #8089 - 115/12kV (D-Sub) - C081675 Driver | Project Print | 26-Nov-24 08:59

#	Activity ID	Activity Name	Original Duration	Start	Finish
1	New Lafayette / Wickford Junction #8089 - 115/12kV (D-Sub) - C081		1249.00	01-Jun-21 A	31-Dec-27
2	Milestones		771.00	16-Dec-24	31-Dec-27
3	Gate Milestones (Scheduled)		297.00	16-Dec-24	18-Feb-26
4	G2	Gate 2 (Detailed Design Validation)	0.00		16-Dec-24
5	G3	Gate 3 (Construction Plan Validation)	0.00		19-May-25
6	G4	Gate 4 (Scheduled In Service)	0.00		21-Jan-26
7	G5	Gate 5 (Project Closure Validation)	0.00		18-Feb-26
8	Gate Milestones (Required)		0.00	31-Dec-27	31-Dec-27
9	GDR	Gate 4 (Required In Service)	0.00		31-Dec-27*
10	Project Milestones		297.00	16-Dec-24	18-Feb-26
11	FEC	FEC (Final Engineering Complete)	0.00		16-Dec-24
12	APR	APR (All Permits Recieved)	0.00		21-Feb-25
13	CS	CS (Construction Start)	0.00		20-May-25
14	CC	CC (Construction Complete)	0.00		07-Jan-26
15	RFL	RFL (Ready For Load)	0.00		21-Jan-26
16	ABC	ABC (As-Builts Complete)	0.00		18-Feb-26
17	FC	FC (Financial Closed)	0.00		18-Feb-26
18	PC	Project Closed	0.00		18-Feb-26
19	Permitting		73.00	07-Nov-24	21-Feb-25
20	State Permitting		77.00	07-Nov-24	21-Feb-25
21	A35170	Assemble State Permit	15.00	07-Nov-24	27-Nov-24
22	A35180	Submit State Permit to Agency	1.00	28-Nov-24	28-Nov-24
23	A35190	Agency Review of State Permit	60.00	29-Nov-24	20-Feb-25
24	A35200	State Permit Approved	1.00	21-Feb-25	21-Feb-25
25	Local Permitting		53.00	07-Nov-24	24-Jan-25
26	A35210	Assemble Building Permit	15.00	07-Nov-24	27-Nov-24
27	A35220	Submit Building Permit to Agency	1.00	28-Nov-24	28-Nov-24
28	A39870	SESC Permit Notification	20.00	07-Nov-24	05-Dec-24
29	A35230	Agency Review of Building Permit	40.00	29-Nov-24	23-Jan-25
30	A35240	Building Permit Approved	1.00	24-Jan-25	24-Jan-25
31	Engineering		424.00	18-Apr-23 A	16-Dec-24
32	A38940	Engineering	424.00	18-Apr-23 A	16-Dec-24
33	Civil Design		111.00	31-May-24 A	06-Nov-24
34	Civil 90% Package		20.00	31-May-24 A	06-Nov-24
35	A39600	Civil Design - 90% Comments / Resolution (Including Cap Bank)	20.00	31-May-24 A	06-Nov-24
36	Electrical Issue for Construction		0.00	06-Nov-24	06-Nov-24
37	A7360	Civil Design Complete (IFC)	0.00		06-Nov-24
38	Substation Design		31.00	01-Nov-24	16-Dec-24
39	Electrical 60% Package		0.00	01-Nov-24	01-Nov-24
40	A38330	Conceptual Electrical Complete (60% Package)	0.00		01-Nov-24*
41	Electrical 90% Package		31.00	01-Nov-24	16-Dec-24
42	A38350	Assemble Final Drawing Package for Submission (90% Package)	10.00	01-Nov-24	14-Nov-24
43	A38380	Submit for Review (90% Package)	10.00	15-Nov-24	29-Nov-24
44	A38390	Review (90% Package)	10.00	02-Dec-24	13-Dec-24
45	A38400	90% Comments	1.00	16-Dec-24	16-Dec-24
46	Electrical Issue for Construction		0.00	16-Dec-24	16-Dec-24
47	A38410	Electrical Design Complete (IFC)	0.00		16-Dec-24
48	Procurement		705.00	01-Jun-21 A	11-Jun-25
49	A38950	Procurement	705.00	01-Jun-21 A	11-Jun-25
50	Scope Package		134.00	07-Nov-24	19-May-25

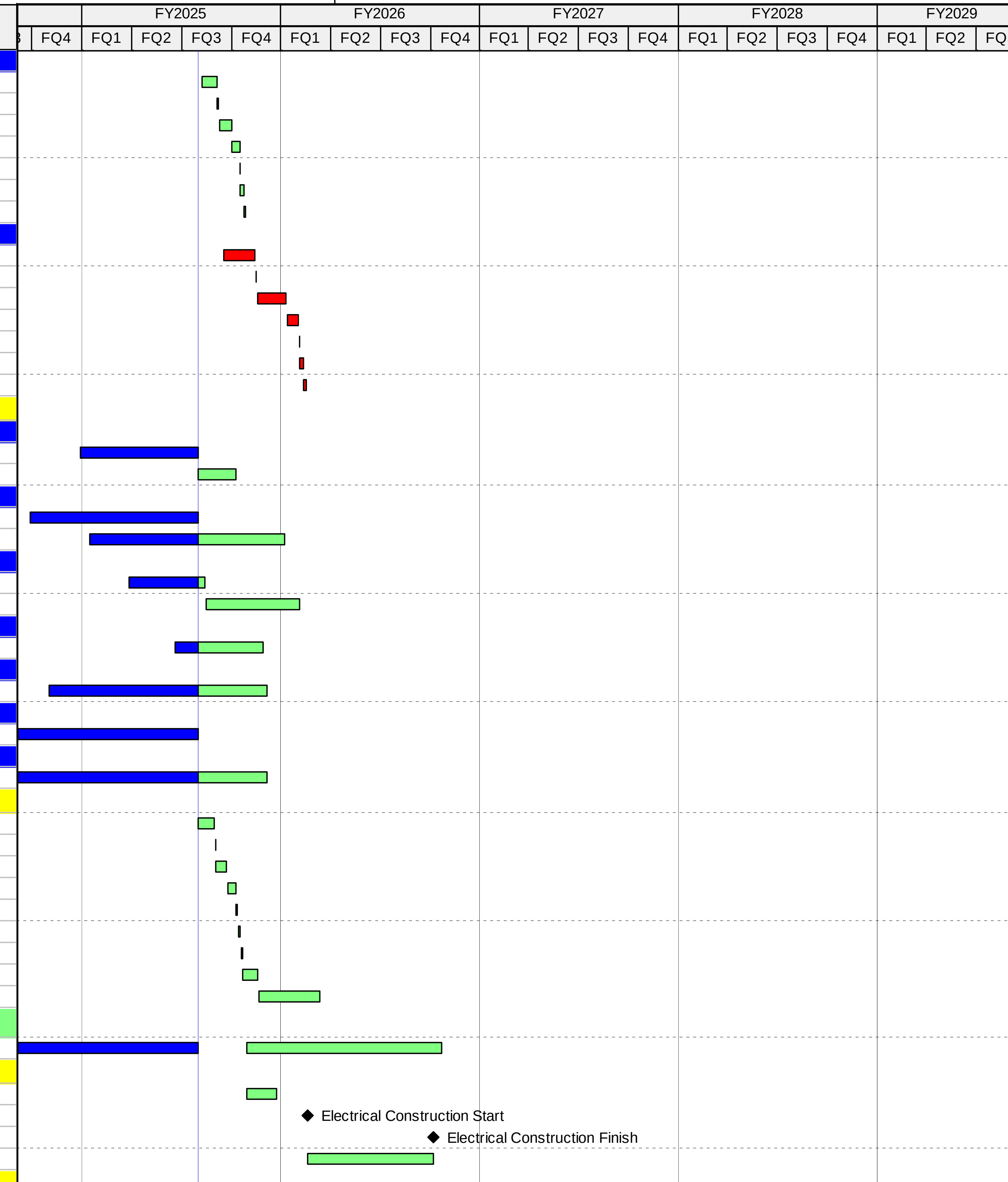


Actual Work | Critical Remaining Work | Remaining Work | Milestone

TASK filter: Remaining Activities.

New Lafayette / Wickford Junction #8089 - 115/12kV (D-Sub) - C081675 Driver | Project Print | 26-Nov-24 08:59

#	Activity ID	Activity Name	Original Duration	Start	Finish
51	Civil Construction		54.00	07-Nov-24	27-Jan-25
52	A39830	Prepare RFP (Civil Construction)	20.00	07-Nov-24	05-Dec-24
53	A39840	Issue RFP for Bid (Civil Construction)	1.00	06-Dec-24	06-Dec-24
54	A39850	RFP Out to Bid (Civil Construction)	15.00	09-Dec-24	31-Dec-24
55	A39860	Review Contractor Bids (Civil Construction)	10.00	02-Jan-25	15-Jan-25
56	A39800	Award Contract (Civil Construction)	1.00	16-Jan-25	16-Jan-25
57	A39810	Create P.O. (Civil Construction)	5.00	17-Jan-25	23-Jan-25
58	A39820	Issue P.O. and Contractor Notice to Proceed (Civil Construction)	2.00	24-Jan-25	27-Jan-25
59	Construction		107.00	17-Dec-24	19-May-25
60	A35450	Prepare RFP (Construction)	40.00	17-Dec-24	13-Feb-25
61	A35440	Issue RFP for Bid (Construction)	1.00	14-Feb-25	14-Feb-25
62	A35430	RFP Out to Bid (Construction)	40.00	17-Feb-25	11-Apr-25
63	A35420	Review Contractor Bids (Construction)	15.00	14-Apr-25	02-May-25
64	A35480	Award Contract (Construction)	1.00	05-May-25	05-May-25
65	A35470	Create P.O. (Construction)	5.00	06-May-25	12-May-25
66	A35460	Issue P.O. and Contractor Notice to Proceed (Construction)	5.00	13-May-25	19-May-25
67	Long Lead Material		471.00	14-Apr-23 A	06-May-25
68	Transformer		220.00	29-Mar-24 A	08-Jan-25
69	A39780	Repair (Transformer)	220.00	29-Mar-24 A	01-Nov-24
70	A39790	Ship / Deliver Repaired Transformer to Site (Transformer)	45.00	01-Nov-24	08-Jan-25
71	Capacitor Bank		322.00	27-Dec-23 A	08-Apr-25
72	A39290	Submittal Review, Development and Approval (Capacitor Bank)	20.00	27-Dec-23 A	01-Nov-24
73	A39300	Fabrication and Delivery of Materials (Capacitor Bank)	250.00	15-Apr-24 A	08-Apr-25
74	Relay Panels		219.00	26-Jun-24 A	06-May-25
75	A39550	Submittal Review, Development and Approval (Relay Panels)	20.00	26-Jun-24 A	13-Nov-24
76	A39560	Fabrication and Delivery of Materials (Relay Panels)	120.00	14-Nov-24	06-May-25
77	Breakers		130.00	18-Sep-24 A	27-Feb-25
78	A39880	Fabrication and Delivery of Materials (Breakers)	130.00	18-Sep-24 A	27-Feb-25
79	Voltage Regulators		275.00	01-Feb-24 A	07-Mar-25
80	A39590	Delivery of Materials (Voltage Regulators)	275.00	01-Feb-24 A	07-Mar-25
81	Circuit Switcher		380.00	14-Apr-23 A	01-Nov-24
82	A39740	Fabrication and Delivery of Materials (Circuit Switcher)	380.00	14-Apr-23 A	01-Nov-24
83	Air Break Switch		275.00	12-May-23 A	07-Mar-25
84	A39750	Fabrication and Delivery of Materials (Air Breaker Switch)	275.00	12-May-23 A	07-Mar-25
85	Miscellaneous Materials		154.00	01-Nov-24	11-Jun-25
86	A38120	Prepare RFP (Miscellaneous Material)	20.00	01-Nov-24	29-Nov-24
87	A38130	Issue RFP for Bid (Miscellaneous Material)	1.00	02-Dec-24	02-Dec-24
88	A38140	RFP Out to Bid (Miscellaneous Material)	15.00	03-Dec-24	23-Dec-24
89	A38150	Review Bids (Miscellaneous Material)	10.00	26-Dec-24	09-Jan-25
90	A38160	Award Contract (Miscellaneous Material)	1.00	10-Jan-25	10-Jan-25
91	A38170	Create P.O. (Miscellaneous Material)	5.00	13-Jan-25	17-Jan-25
92	A38180	Issue P.O. and Contractor Notice to Proceed (Miscellaneous Material)	2.00	20-Jan-25	21-Jan-25
93	A38190	Submittal Review, Development and Approval (Miscellaneous Material)	20.00	22-Jan-25	18-Feb-25
94	A38200	Fabrication and Delivery of Materials (Miscellaneous Material)	80.00	19-Feb-25	11-Jun-25
95	Construction		541.00	19-Oct-23 A	21-Jan-26
96	A38960	Construction	541.00	19-Oct-23 A	21-Jan-26
97	Substation Construction		240.00	28-Jan-25	07-Jan-26
98	A39610	Civil Construction (Add'l Foundations)	40.00	28-Jan-25	24-Mar-25
99	A38990	Electrical Construction Start	0.00	20-May-25	
100	A39030	Electrical Construction Finish	0.00		07-Jan-26
101	A39000	Substation Electrical Construction	160.00	20-May-25	07-Jan-26
102	Outages		5.00	08-Jan-26	14-Jan-26



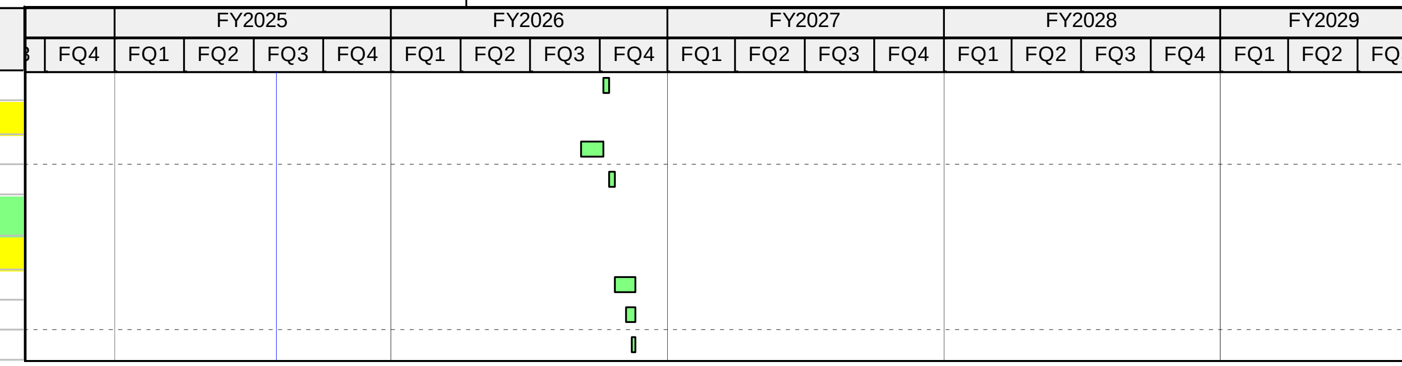
Actual Work | Critical Remaining Work | Remaining Work | Milestone

Page 2 of 3

TASK filter: Remaining Activities.

New Lafayette / Wickford Junction #8089 - 115/12kV (D-Sub) - C081675 Driver | Project Print | 26-Nov-24 08:59

#	Activity ID	Activity Name	Original Duration	Start	Finish
103	A39640	Outage Window	5.00	08-Jan-26	14-Jan-26
104	Testing and Commissioning		30.00	08-Dec-25	21-Jan-26
105	A39620	Substation Testing (Pre Outage Testing)	20.00	08-Dec-25	07-Jan-26
106	A39630	Substation Testing (Post Outage Testing)	5.00	15-Jan-26	21-Jan-26
107	Close Out		20.00	22-Jan-26	18-Feb-26
108	Contract Close out		20.00	22-Jan-26	18-Feb-26
109	A1360	Complete and Issue As-Built Drawings	20.00	22-Jan-26	18-Feb-26
110	A1370	Work Orders Closed in PowerPlant	10.00	05-Feb-26	18-Feb-26
111	A1380	Funding Project Closed	5.00	12-Feb-26	18-Feb-26



Actual Work | Critical Remaining Work | Remaining Work | Milestone

TASK filter: Remaining Activities.

Division 1-49
System Capacity & Performance

Request:

Provide a list of major equipment required for New Lafayette, dates ordered (or to be ordered), scheduled delivery (or anticipated delivery), and cost.

Response:

The Company considers major equipment to be equipment that is forecasted to individually cost more than $50,000. Please see the table below for a list of the major equipment required for the New Lafayette / Wickford 8089 Substation.

For definitions, the Order Date is when the Purchase Order is sent out to the awarded Supplier, and the Delivery Date is when the equipment is expected to arrive. The procurement process, including necessary Request for Proposal (RFP) cycles and negotiation occurs before the Order Date.

	(a)	(b)	(c)	(d)	(e)
	Major Equipment Description	**Qty**	**Order Date**	**Delivery Date**	**Approximate Cost**
1	Transformer	1	11/5/2021	March 31, 2025	$964,291.00
2	Relay Panel Package	1	6/21/2024	June 30, 2025	$284,614.00
3	Capacitor Bank	1	12/28/2023	June 30, 2026	$327,379.20

Prepared by or under the supervision of: Daniel Glenning

Division 1-50
System Capacity & Performance

Request:

The Company's South County West (SCW) Area Study (page 21) states:

> "While building out the second half of Chase Hill Substation is the more expensive option, it is, however, the recommended option. This option aligns the Study with the large Distributed Generation penetration in the area, some of which could potentially require this substation to be fully built out to interconnect the projects. The Company will make sure to align the DG project scopes with the recommendations of this plan to move forward with the most optimal and logical solution set."
>
> Please explain in more detail how DG projects would utilize the second half of Chase Hill Substation, particularly in terms of equipment and capacity availability. If a DG project interconnects to the second half, is the capacity then unavailable to serve customers? Will RIE assess any costs to DG customers to utilize the expanded station? If the Company did not build out the second half of the substation, would the DG customer be responsible for the cost to expand the station if those modifications were required to interconnect?

Response:

Distributed Generation (DG) projects would utilize the second half of Chase Hill Substation by interconnecting to the circuits sourced from this second part of the substation. The equipment and generation capacity used would depend on the specific interconnection applications. If a DG project interconnects to the second half, the capacity is still available to serve customers. The DG customer is a generator and, for purposes of this response, uses 'reverse' capacity. For purposes of this response, the distribution load customers can be considered to use 'forward' capacity. To the extent the generation is timed with the load, the generation offsets the load and enables more forward capacity upstream of the generator. There is no reduced capacity for load customers. Because the station project is a System Improvement, Rhode Island Energy cannot assess costs to DG customers per Sections 1.2, 5.2, and 5.4(a)a of R.I.P.U.C. 2258, Standards for Connecting Distributed Generation (DG Interconnection Tariff).

If: (i) the system needs did not exist, (ii) the Company did not build out the second half of the substation, and (iii) the second half of the station was found to be required for a DG customer, then the second half of the station would be a System Modification. For System Modifications, the cost is charged to the interconnecting DG customer. If system needs were to arise after the DG interconnection that would have required the second half of the station, then there may be some reimbursement to the DG customer if the second half of the station was determined to be an Accelerated Modification under Section 5,4(c) or 5.4(d) of the DG Interconnection Tariff.

Division 1-51

System Capacity & Performance

Request:

Are there pending DG applications that require Chase Hill substation expansion to interconnect? What steps or actions has the Company made to make sure to align DG project scopes with the plan recommendations and to appropriately identify cost responsibilities?

Response:

There are no pending distributed generation (DG) applications that require the Chase Hill Substation expansion to interconnect. There are, therefore, currently no cost responsibilities to assign to pending DG applications under R.I.P.U.C. 2258, Standards for Connecting Distributed Generation (DG Interconnection Tariff).

The Company notes, and has explained in previous proceedings, that system needs based projects can also increase hosting capacity for DG. This does not create a cost allocation issue. Instead, the Company is highlighting that some system improvements projects also contribute toward achieving the State's climate policy goals as a secondary benefit.

Prepared by or under the supervision of: Ryan Constable

Division 1-52
Asset Condition

Request:

Provide a line-item capex cost estimate for the recommended Chase Hill solution totaling $5.030 million in the SCW Area Study as compared to the proposed ISR Plan spend totaling $6.55 million. Explain the differences. For major equipment, provide the Company's current cost estimates based on its most recent purchases compared to the Area Study and ISR Plan estimates.

Response:

Please see the following tables of cost estimates.

From the original SCW Area Study:

Spend Type	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030+	Total
CAPEX	$0.000	$1.006	$2.012	$1.006	1.006	$0.00	$5.030
OPEX	$0.000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.000
REMOVAL	$0.000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.000
TOTAL	$0.000	$1.006	$2.012	$1.006	$1.006	$0.000	$5.030

Updated cash flows from the proposed ISR Plan spend:

Spend Type	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030+	Total
CAPEX	$0.000	$0.300	$3.544	$1.333	$1.373	$0.000	$6.550
OPEX	$0.000	$0.000	$0.000	$0.000	$0.00	$0.00	$0.000
REMOVAL	$0.000	$0.000	$0.000	$0.000	$0.00	$0.00	$0.000
TOTAL	$0.000	$0.300	$3.544	$1.333	$1.373	$0.000	$6.550

The differences in the cash flows are based solely on Consumer Price Index ("CPI") inflation adjustments. Under the National Grid process, a detailed itemized estimate was not developed. As a result, the Company is not able to calculate a comparison of its current cost estimates based on the most recent major equipment purchases to the Area Study and ISR Plan estimates.

Prepared by or under the supervision of: Ryan Constable

Division 1-53
Asset Condition

Request:

The alternative solution to expanding Chase Hill is to create and firm up distribution feeder ties at a capex of $4.2 million (SCW Area Study, page 21). The Company states that the alternative would require drop and pick operations, have a negative impact on RI reliability and reduce operational usefulness. Given that the preferred solution is now $2.3 million more than the alternative, will the Company reexamine the alternatives in light of cost increases? Why or why not?

Response:

For a comparison of alternatives, all options would need to be adjusted for inflation in the same manner as option one (see the Company's response to Division 1-52). In this case, the alternative solution would increase to $5.5 million using Consumer Price Index inflation values.

Based on the adjustment for inflation, the cost difference between the preferred solution (i.e., expanding Chase Hill) and the alternative solution remains comparable to the study evaluation; therefore, the Company still recommends building out the second half of Chase Hill for its superior operational and reliability characteristics.

Division 1-54
System Capacity & Performance

Request:

The Company has expended $415,000 to procure a house and land adjacent to the Nasonville site to avoid building a sound wall to mitigate transformer noise. Did the original Area Study recommendation include costs for a sound wall? Please provide analysis or documentation confirming that the land purchase will effectively mitigate transformer noise for other nearby residences and will meet the local noise ordinance.

Response:

The Northwest Rhode Island Area Study did not consider a sound wall with the transformer addition at the Nasonville Substation. The Noise Study determined that mitigation was required only in the vicinity of the land adjacent to the substation and that other nearby residences did not require noise mitigation. The Company hired a consultant, GZA GeoEnvironmental, Inc., to perform a Noise Study analysis that concluded that "Article II, Section 16-39 of the Town of Burrillville Code of Ordinance" would not be met in the vicinity of the land adjacent to the substation, but that no other mitigation would be necessary. To meet the town's sound limits for the land adjacent to the substation, a sound wall would be required. Please see Attachment Division 1-54-1 for a copy of the Noise Study. By procuring the residential property, the Company effectively avoided more than $750,000 in costs by eliminating the need for the sound wall, landscaping requested by the town of Burrillville, and future liability concerns with the home's location being landlocked by the substation. Please see Attachment DIV 1-54-2 for a copy of the Company's analysis of these avoided costs.

GZA
Known for excellence.
Built on trust.

Geotechnical
Environmental
Ecological
Water
Construction Management

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Suite 300
Providence, RI 02909
T: 401.421.4140
F: 401.751.8613
www.gza.com

Via Email to *WRHoward@RIEnergy.com*

October 16, 2023
File No. 03.005174.02

Mr. William Howard
Rhode Island Energy

Re: Noise Study Results
Nasonville Substation Rebuild / Expansion
466 Douglas Turnpike
Burrillville, Rhode Island

Dear Mr. Howard:

GZA GeoEnvironmental, Inc. (GZA) completed an evaluation of local and State-level noise requirements and collected background sound level measurements for the proposed rebuild / expansion of the Nasonville Substation for Rhode Island Energy. In addition, SoundPlan noise modeling was completing. Modeled noise sources included two (2) transformers. Our work and the findings described herein are subject to the limitations included in **Attachment C**.

PROJECT SCOPE

GZA understands that Rhode Island Energy plans to rebuild and expand the existing Nasonville Substation located at 466 Douglass Turnpike in Burrillville, Rhode Island. Noise emissions sources at the proposed substation include two (2) transformers with a 33/44/55 MVA rating with a NEMA specification of 66/69 dB(A).

NOISE REQUIREMENT FINDINGS

Noise Regulations

The Site is located within the town of Burrillville within the State of Rhode Island. Burrillville has a noise ordinance as part of their Code of Ordinances found inf the Revised General Ordinances Town of Burrillville, Rhode Island 2004 Article II. Noise. The noise requirements that are applicable to the project are summarized in **Table 1** and **Table 2**.

Table 1. Summary of Noise Regulations
Town of Burrillville, Rhode Island
In accordance with Article II, Section 16-39 of the Town of Burrillville Code of Ordinances, noise from the project cannot exceed the maximum permissible sound levels identified in **Table 2**. Based on the residential land uses for the land adjacent to north and south of the Site noise from the proposed development will be subject to the following limits: • **53 decibels during the day (7:00 AM – 10:00 PM)**; and • **43 decibels at night (10:00 PM – 7:00 AM)**
Notes: 1. Town of Burrillville Code of Ordinances, https://library.municode.com/ri/burrillville/codes/code_of_ordiances 2. Town of Burrillville Mapper https://www.axisgis.com/burrillvilleri/

Table 2.
Zoning District Noise Standard
Maximum Allowable Octave Band Sound Pressure Levels1

	Residential		Business Limited & General		Commercial Industrial
Octave Band Center Frequency of all Measurement (HZ)>	Daytime	All Other Times	Daytime	All Other Times	Daytime
31.5	61	53	66	58	68
63	60	52	65	57	67
125	56	48	61	53	63
250	54	44	59	49	59
500	50	40	55	45	55
1000	47	37	52	42	52
2000	43	33	48	38	48
4000	39	29	44	34	44
8000	38	28	43	33	43
Single number Equivalent	53 dB(A)	43 dB(A)	58 dB(A)	48 dB(A)	58 dB(A)

1 Unless otherwise noted, values given in the following table ad dB, i.e. no adjustments for "A" or "C" weighting

(a) With the exception of sound levels elsewhere specifically authorized or allowed in this article or exempted by this article or by special use permit, the above are the maximum permissible sound levels allowed at or within the real property boundary of a receiving land use.

(b) For any source of sound which emits a tone, the maximum sound-pressure level limits and single-number equivalents set forth in subsection (a) of this section shall be reduced by five dB.

(c) Exceptions to table I are activities covered in sections 16-35 and 16-36.

Sensitive Receivers

Adjacent land use and sensitive receivers are summarized in **Table 3**. Land use and sensitive receivers were identified based on a review of images available from Google Earth and from the Burrillville, Rhode Island Mapper.[1] Zoning is based on information obtained from the Burrillville Rhode Island Mapper. A zoning map for the Site vicinity is included in **Attachment A**.

Beyond the adjacent properties, other sensitive receivers (residential developments and schools) are located within a half mile north and east of the Site.

Table 3. Summary of Adjacent Land Use, Zoning, and Sensitive Receivers[1]				
Proximity to Site	**Address**	**Land use**	**Zoning**	**Sensitive Receiver?[2]**
Site	8765 and 8819 Wellington Road	Substation	Farming Residential (F2)	--
Northeast, adjacent to site	405 Douglass Turnpike	Residential	Farming Residential (F2)	Yes
Southwest, across Douglas Turnpike	152 Walling Road	Residential	Farming Residential (F5)	Yes

Notes:
1. Land use and sensitive receivers were identified based on a review of images available from Google Earth and from the Town of Burrillville Mapper (https://www.axisgis.com/burrillvilleri/). Zoning is based on the October 2022 Town of Burrillville, Rhode Island Zoning Districts Map.
2. Sensitive receivers include residences, schools, and hospitals.

BACKGROUND SOUND LEVEL MEASUREMENTS

Sensitive Receivers

Sound level measurements were taken in the vicinity of the proposed Site on March 29 through March 31, 2023 using the following equipment and procedures:

- Measurements were taken using a Type I sound level meter meeting standards prescribed by the American National Standards Institute, Inc. (ANSI) and maintained in calibration and good working order. Field calibration was preformed prior to and after each measurement.
- Measurements were taken using the slow response setting on the sound level meter, with the microphone positioned to limit unnatural enhancement or diminution of the measured noise.
- Measurements were collected at the Project Site and at the property boundaries of the two sensitive receptors. These locations are identified as Location 1, Location 2, and Location 3 in **Figure 1**.
- At each of the three measurement locations measurements were collected for a 51-hour period.

During the measurements, the ambient temperature ranged from a high of approximately 42°F during the day to a low of approximately 30°F at night. The wind was generally calm, and there was no precipitation. Notable nearby noise sources included vehicular traffic along Douglas Turnpike. It is noted that the background noise

[1] https://www.axisgis.com/burrillvilleri/

measurement results are above the maximum allowable sound levels as per Burrillville, Rhode Island. This is most likely due to vehicular traffic on Douglas Turnpike .

Results

Noise measurements are summarized in **Table 4** below with raw meter outputs, field notes, and calibration certificates provided in **Attachment B.** Noise measurements are presented as the equivalent noise level (Leq) for each noise measurement period averaged for nighttime and daytime as well as the lowest measured Leq for each measurement period. The noise data is presented as daytime and nighttime averages. **Figures 2, 3, and 4,** attached, show the noise levels presented in hourly equivalent noise levels (Leq) for each noise location in graph form.

Table 4. Background Noise Level Measurements

Measurement Locations	Measurement Period	Average Measured Sound Level (dBA) (L_{eq})	Lowest Measured Sound Level (L_{eq})	Maximum Permissible Sound Level (dBA)
Location 1 (daytime)	7:00 am – 10:00 pm	57.46	48.6	60
Location 1 (nighttime)	10:00 pm – 7:00 am	53.71	48.7	55
Location 2 (daytime)	7:00 am – 10:00 pm	47.16	33.1	60
Location 2 (nighttime)	10:00 pm – 7:00 am	42.26	32.4	55
Location 3 (daytime)	7:00 am – 10:00 pm	58.91	27.0	60
Location 3 (nighttime)	10:00 pm – 7:00 am	51.06	25.2	55

NOISE MODELING / EXPECTED SOUND LEVELS

SoundPlan noise modeling of the noise emissions sources at the rebuild and expansion of the Nasonville Substation was completed as per the below. Additional modeling may be conducted to refine the mitigation further.

<u>Northeast Residential Receptor</u>

Based on the sound emissions from the proposed transformers, it was determined that mitigation was necessary to lower the sound levels at the residential receptors to the northeast of the Site. Four different scenarios of mitigation were modeled. All scenarios include a wall along the entire northeast property line of the Site. The scenarios include a 10’ barrier, 15’ barrier, 18’ barrier, and 20’ barrier. **Table 5** below and **Figure 5** attached show the results of these scenarios.

Table 5. Northeast Receptor Expected Sound Levels										
Results at Northeast Receptor	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dB(A)**
10' Barrier	46	49	57	46	44	38	34	28	21	46
15' Barrier	46	48	56	43	40	34	29	23	16	43
18' Barrier	46	48	55	42	39	32	25	17	9	42
20' Barrier	46	48	54	41	37	29	22	14	4	41

Southwest Residential Receptor

Based on the sound emissions from the proposed transformers, it was determined that no mitigation is to be installed on the southwest property boundary. **Table 6** below and the above referenced figures show the results of the modeling at the southwest residential receptor.

Table 6. Southwest Receptor Expected Sound Levels										
Results at South Receptor	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dB(A)**
No Barrier	45	48	56	45	45	37	32	25	16	46

During modeling, it was found that the octave bands produced by the proposed transformers produce a tone. Therefore, the maximum allowable sound levels are reduced by 5 dB. This results in the daytime regulation being 48 dB(A) and the nighttime regulation being 38 dB(A) at the residential receptors.

This information is intended to aid in further discussion related to potential noise mitigation measures. Upon review and discussion of these results, additional model iterations may be conducted to explore changes to design and/or potential noise mitigation measures. If needed, final results will be summarized in a separate report.

CLOSING

We appreciate this opportunity to assist Rhode Island Energy with this matter and look forward to working with you as this important project progresses. Should you have any questions regarding the information provided herein, please contact Kenneth Boivin at 603-566-9784 or Gene Bove at 973-534-4090.

Sincerely,

GZA GEOENVIRONMENTAL, INC.

Gene Bove
Project Manager

Timothy Kelly
Consultant/Reviewer

Kevin Williams AICP, PP
Associate Principal

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Figures:
Figure 1 – Baseline Noise Monitoring Location Map
Figure 2 – Noise Monitoring Location 1 Graph
Figure 3 – Noise Monitoring Location 2 Graph
Figure 4 - Noise Monitoring Location 3 Graph
Figure 5 –Barrier Results Map

Attachments:
Attachment A – Burrillville, Rhode Island Zoning Map
Attachment B – Noise Meter Raw Outputs, Field Notes, Calibration Certificates, Photos
Attachment C - Limitations

Figure 1 – Baseline Noise Monitoring Locations Map

Legend

Noise Monitoring Locations

N

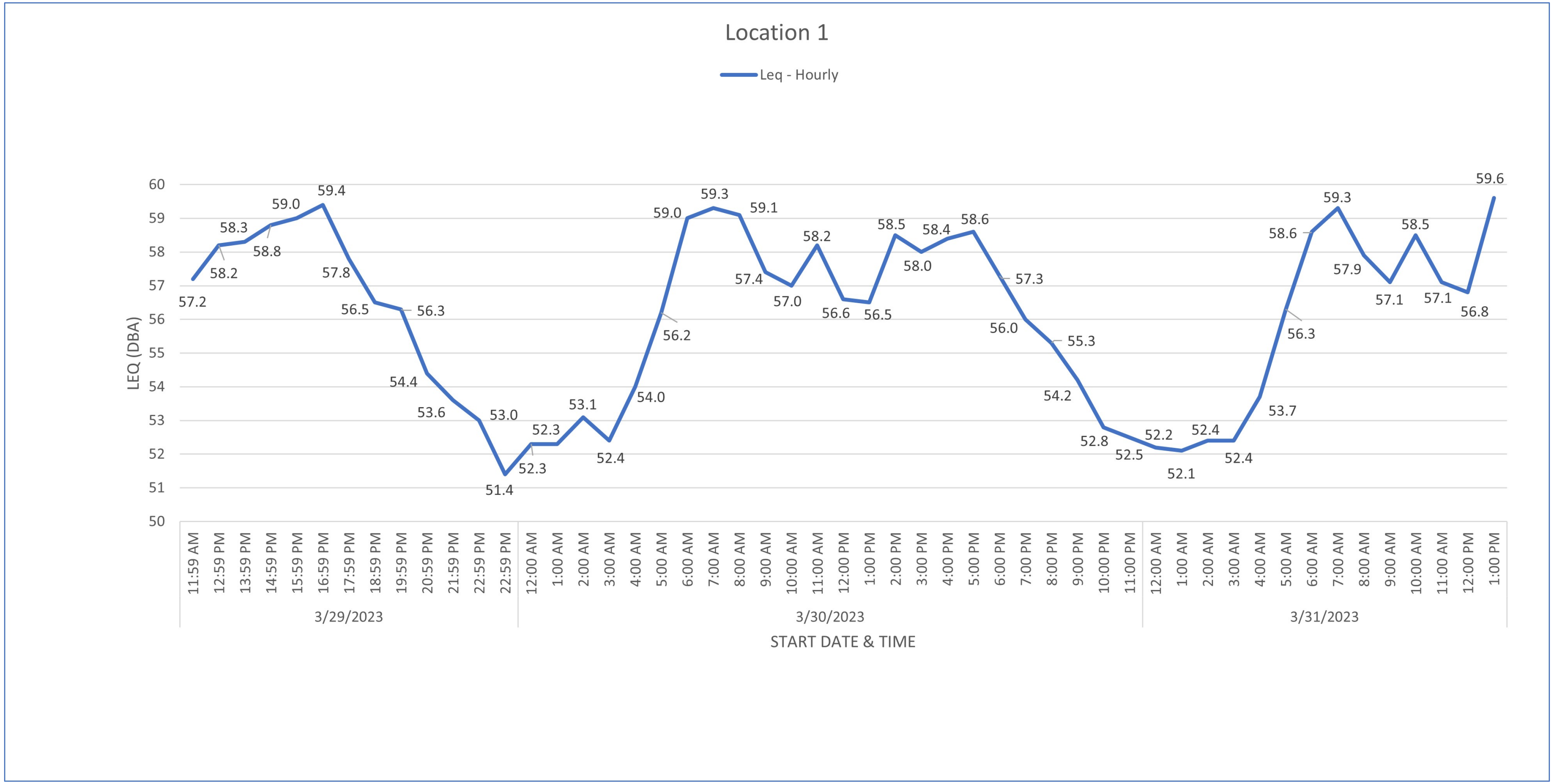
0 30 60 120 US Feet

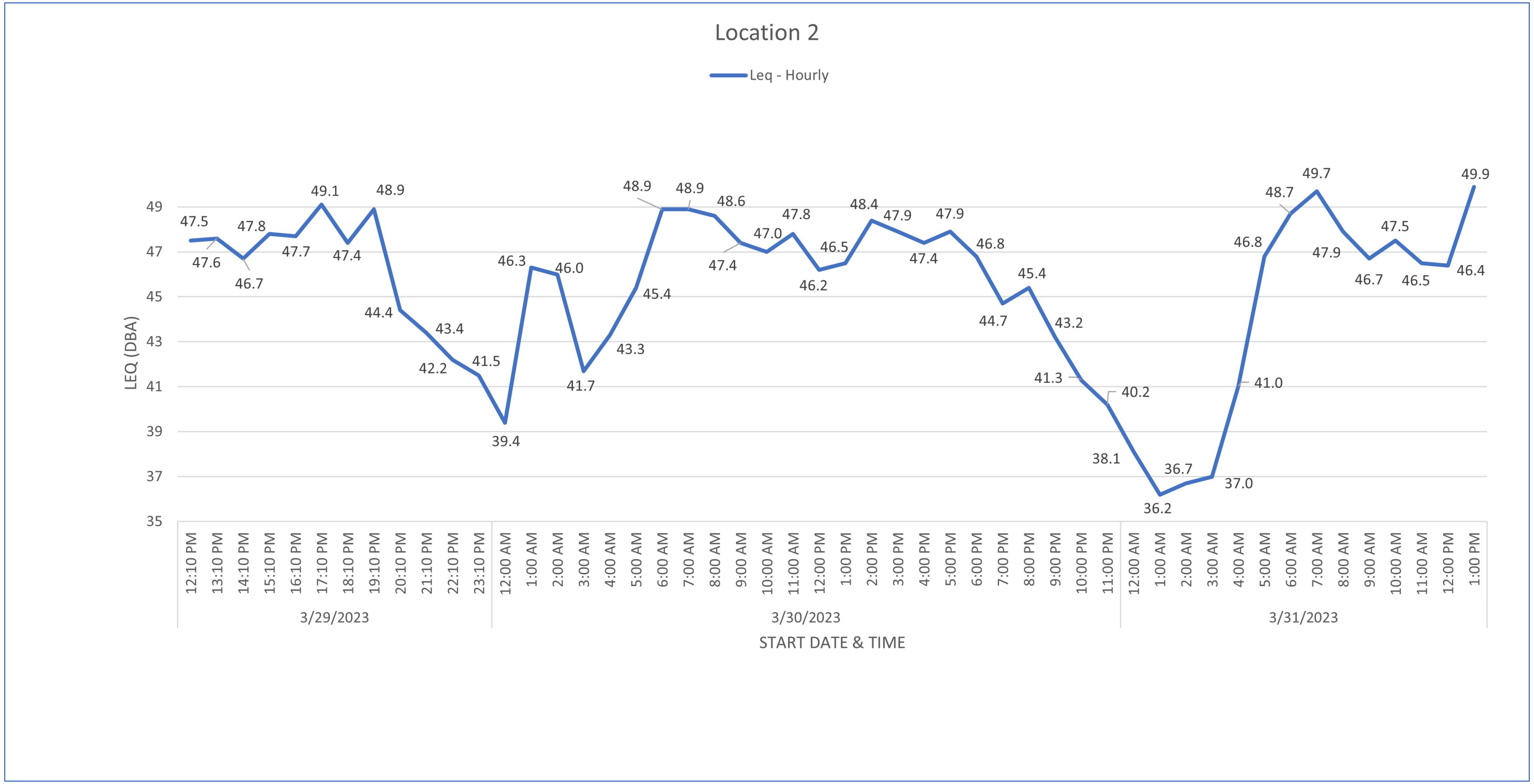
NASONVILLE SUBSTATION
BURRILVILLE, RHODE ISLAND

NOISE MONITORING LOCATION MAP

PREPARED BY: equity environmental engineering A Division of GZA		PREPARED FOR: NARRAGANSETT ELECTRIC COMPANY	
PROJ MGR: JR	REVIEWED BY: GB	CHECKED BY: JR	FIG/DWG 1
DESIGNED BY: GB	DRAWN BY: GB	SCALE: 1:1,108	
DATE: 03/27/2023	PROJECT NO: 35174.02	REVISION NO:	SHEET NO: 1 OF 1

Figure 2 – 4 – Noise Monitoring Locations 1 -3 Graphs


Location 1
Leq - Hourly
LEQ (DBA)
START DATE & TIME
3/29/2023
3/30/2023
3/31/2023


Location 2
Leq - Hourly
LEQ (DBA)
START DATE & TIME
3/29/2023
3/30/2023
3/31/2023

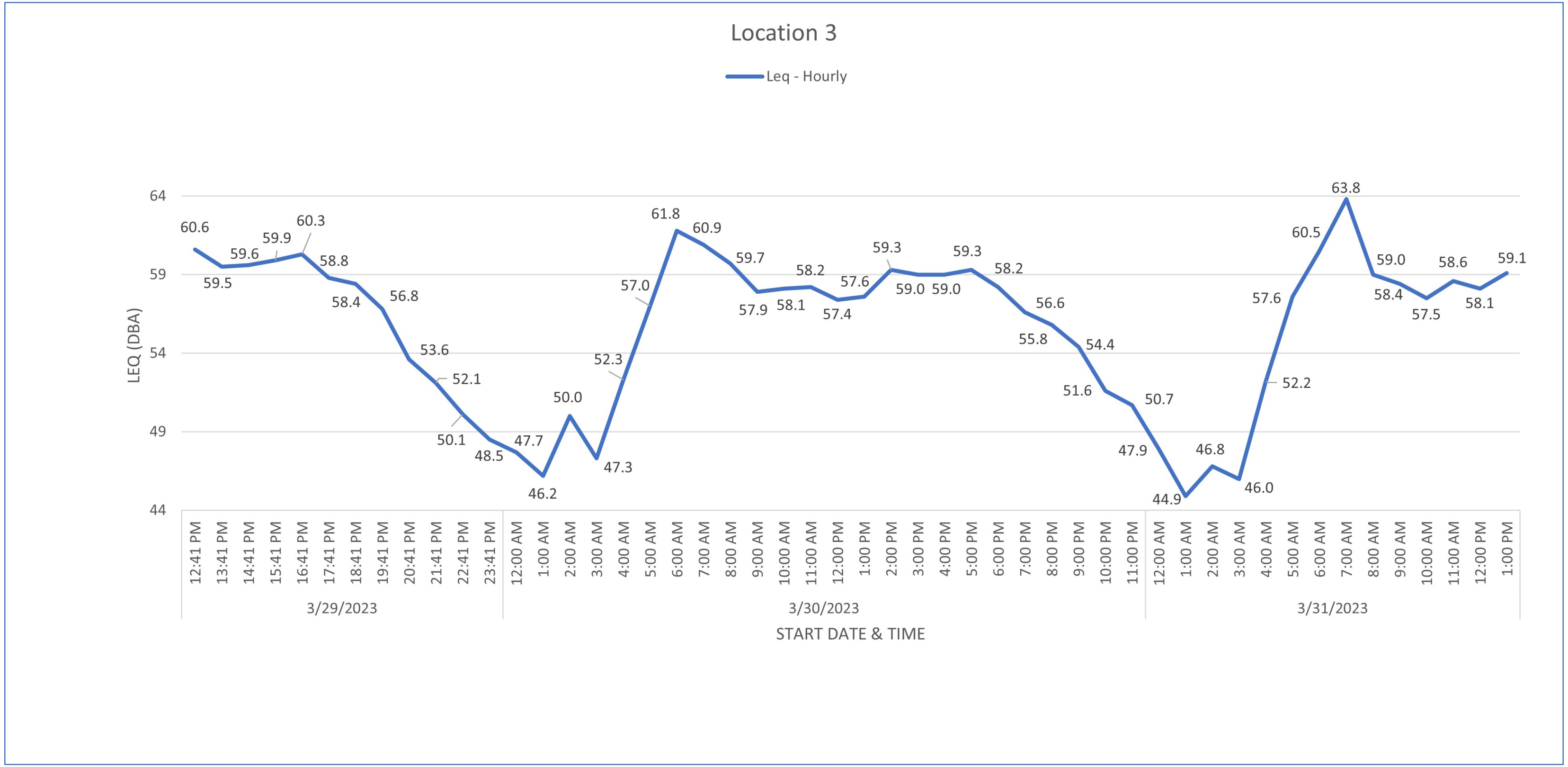
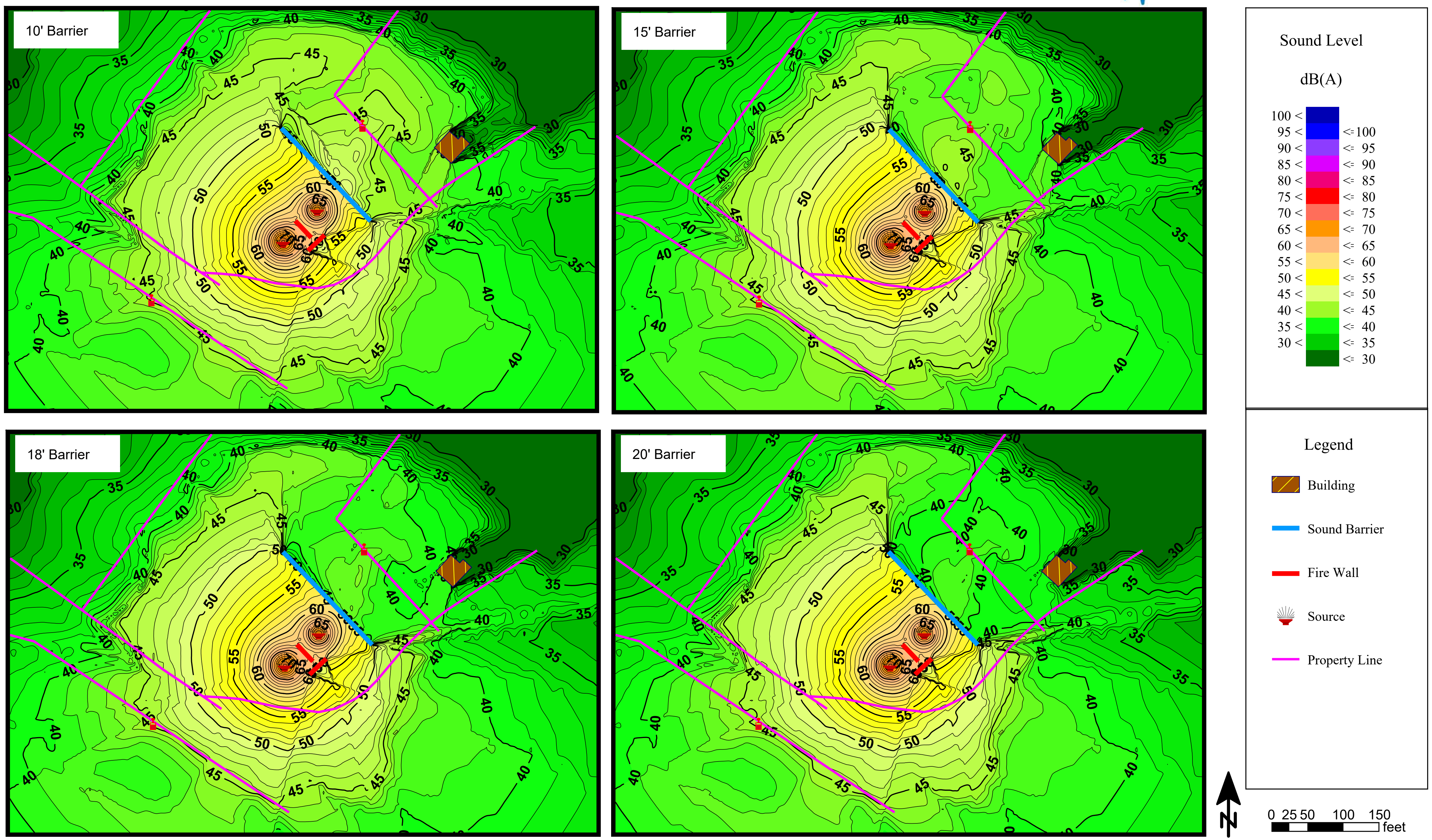

Location 3
Leq - Hourly
LEQ (DBA)
START DATE & TIME
3/29/2023
3/30/2023
3/31/2023

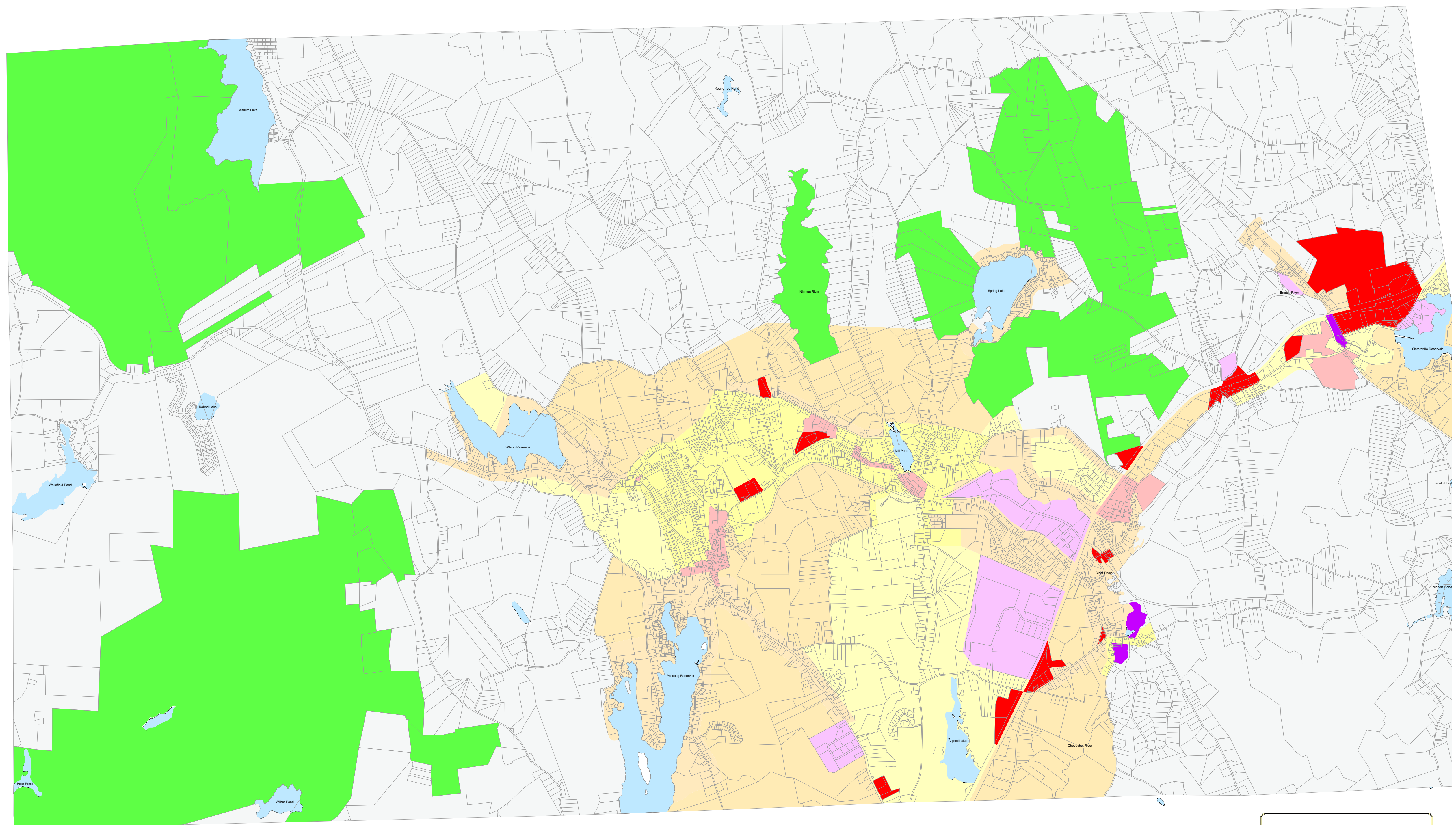
Figure 5 – Barrier Results Map

Expected A-weighted Sound Levels Contours due to Transformer Noise, Nasonville, Rhode Island.

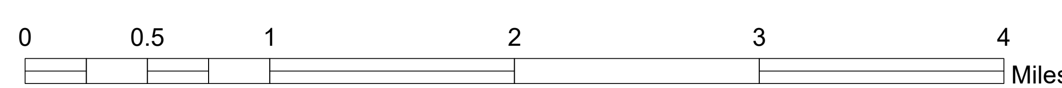
Lewis S. Goodfriend & Associates
CONSULTING ENGINEERS IN ACOUSTICS

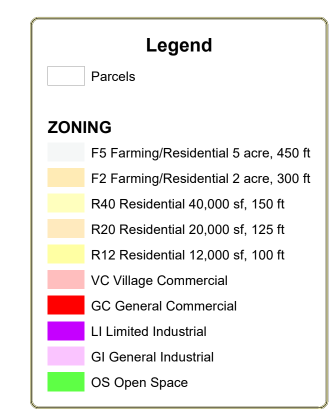


Attachment A – Burrillville, Rhode Island Zoning Map



Town of Burrillville, Rhode Island
Zoning Districts
Adopted: August 17, 2022





Attachment B – Raw Noise Meter Outputs, Field Notes, Calibration Certificates, Photos

Start Date & Time	LAeq	LASmin	LAS 50%	LAS 10%	LASmax	LAS 90%
3/29/2023 11:59	57.2 dB	49.2 dB	53.0 dB	60.5 dB	75.0 dB	51.5 dB
3/29/2023 12:59	58.2 dB	50.5 dB	53.5 dB	61.0 dB	82.9 dB	51.5 dB
3/29/2023 13:59	58.3 dB	51.3 dB	54.0 dB	62.0 dB	75.2 dB	52.0 dB
3/29/2023 14:59	58.8 dB	50.6 dB	54.5 dB	62.5 dB	78.2 dB	52.0 dB
3/29/2023 15:59	59.0 dB	50.3 dB	56.0 dB	62.5 dB	73.4 dB	52.0 dB
3/29/2023 16:59	59.4 dB	50.0 dB	56.5 dB	63.0 dB	78.0 dB	51.5 dB
3/29/2023 17:59	57.8 dB	49.1 dB	54.0 dB	61.5 dB	78.1 dB	51.0 dB
3/29/2023 18:59	56.5 dB	49.8 dB	52.0 dB	60.5 dB	77.3 dB	51.0 dB
3/29/2023 19:59	56.3 dB	49.9 dB	52.0 dB	60.0 dB	74.7 dB	50.5 dB
3/29/2023 20:59	54.4 dB	49.8 dB	51.5 dB	57.5 dB	68.4 dB	50.5 dB
3/29/2023 21:59	53.6 dB	49.3 dB	51.0 dB	54.5 dB	75.9 dB	50.0 dB
3/29/2023 22:59	53.0 dB	49.6 dB	51.0 dB	53.5 dB	70.8 dB	50.5 dB
3/29/2023 23:59	51.4 dB	50.6 dB	51.0 dB	52.0 dB	53.1 dB	50.5 dB
3/30/2023 0:00	52.3 dB	49.7 dB	51.0 dB	52.0 dB	72.6 dB	50.5 dB
3/30/2023 1:00	52.3 dB	50.1 dB	51.5 dB	53.0 dB	66.3 dB	51.0 dB
3/30/2023 2:00	53.1 dB	50.4 dB	52.0 dB	54.5 dB	69.3 dB	51.0 dB
3/30/2023 3:00	52.4 dB	50.2 dB	51.5 dB	52.5 dB	67.5 dB	51.0 dB
3/30/2023 4:00	54.0 dB	50.5 dB	52.0 dB	54.5 dB	72.3 dB	51.5 dB
3/30/2023 5:00	56.2 dB	50.2 dB	52.5 dB	59.5 dB	76.7 dB	51.5 dB
3/30/2023 6:00	59.0 dB	50.5 dB	54.5 dB	63.0 dB	72.8 dB	52.0 dB
3/30/2023 7:00	59.3 dB	50.3 dB	55.5 dB	63.5 dB	75.0 dB	52.0 dB
3/30/2023 8:00	59.1 dB	50.0 dB	56.5 dB	63.0 dB	74.2 dB	52.0 dB
3/30/2023 9:00	57.4 dB	50.3 dB	53.0 dB	61.0 dB	75.9 dB	51.5 dB
3/30/2023 10:00	57.0 dB	48.9 dB	52.5 dB	60.5 dB	78.3 dB	50.5 dB
3/30/2023 11:00	58.2 dB	49.5 dB	52.0 dB	60.0 dB	83.5 dB	50.5 dB
3/30/2023 12:00	56.6 dB	49.6 dB	52.0 dB	60.5 dB	71.2 dB	50.5 dB
3/30/2023 13:00	56.5 dB	49.0 dB	52.5 dB	60.5 dB	72.4 dB	51.0 dB
3/30/2023 14:00	58.5 dB	49.7 dB	54.0 dB	61.5 dB	76.9 dB	51.5 dB
3/30/2023 15:00	58.0 dB	49.9 dB	54.0 dB	61.5 dB	74.2 dB	51.0 dB
3/30/2023 16:00	58.4 dB	49.7 dB	54.5 dB	62.0 dB	80.2 dB	51.0 dB
3/30/2023 17:00	58.6 dB	50.0 dB	55.5 dB	62.5 dB	73.9 dB	51.0 dB
3/30/2023 18:00	57.3 dB	49.1 dB	53.0 dB	61.5 dB	73.3 dB	50.5 dB
3/30/2023 19:00	56.0 dB	48.8 dB	51.5 dB	60.5 dB	77.6 dB	49.5 dB
3/30/2023 20:00	55.3 dB	48.6 dB	51.0 dB	59.5 dB	69.2 dB	49.5 dB
3/30/2023 21:00	54.2 dB	48.8 dB	50.5 dB	57.5 dB	71.0 dB	49.5 dB
3/30/2023 22:00	52.8 dB	48.7 dB	50.0 dB	54.5 dB	69.0 dB	49.5 dB
3/30/2023 23:00	52.5 dB	49.2 dB	50.5 dB	53.0 dB	69.3 dB	50.0 dB
3/31/2023 0:00	52.2 dB	50.2 dB	51.0 dB	52.0 dB	65.7 dB	50.5 dB
3/31/2023 1:00	52.1 dB	50.8 dB	51.5 dB	52.0 dB	65.8 dB	51.5 dB
3/31/2023 2:00	52.4 dB	51.3 dB	52.0 dB	52.0 dB	68.4 dB	51.5 dB
3/31/2023 3:00	52.4 dB	51.0 dB	52.0 dB	52.5 dB	66.4 dB	51.5 dB
3/31/2023 4:00	53.7 dB	51.0 dB	52.0 dB	54.0 dB	71.6 dB	51.5 dB
3/31/2023 5:00	56.3 dB	50.2 dB	51.5 dB	59.5 dB	76.7 dB	51.0 dB
3/31/2023 6:00	58.6 dB	50.4 dB	54.5 dB	63.0 dB	73.2 dB	51.5 dB
3/31/2023 7:00	59.3 dB	50.8 dB	56.5 dB	63.0 dB	72.4 dB	52.0 dB
3/31/2023 8:00	57.9 dB	49.5 dB	53.5 dB	62.0 dB	78.7 dB	50.5 dB

3/31/2023 9:00	57.1 dB	49.0 dB	52.5 dB	61.0 dB	72.4 dB	50.5 dB
3/31/2023 10:00	58.5 dB	49.6 dB	52.5 dB	61.0 dB	78.7 dB	50.5 dB
3/31/2023 11:00	57.1 dB	49.7 dB	52.5 dB	61.0 dB	72.7 dB	51.0 dB
3/31/2023 12:00	56.8 dB	49.2 dB	52.5 dB	60.5 dB	72.2 dB	50.5 dB
3/31/2023 13:00	59.6 dB	50.0 dB	55.0 dB	62.5 dB	76.6 dB	51.0 dB

Notes

Start Date & Time	LAeq	LASmin	LAF 50%	LAF 10%	LASmax	LAF 90%	Notes
3/29/2023 12:10	47.5 dB	33.9 dB	44.0 dB	49.5 dB	72.6 dB	37.0 dB	
3/29/2023 13:10	**47.6 dB**	**34.1 dB**	**44.0 dB**	**50.0 dB**	**72.6 dB**	**37.5 dB**	
3/29/2023 14:10	46.7 dB	33.1 dB	44.0 dB	50.0 dB	63.4 dB	37.0 dB	
3/29/2023 15:10	47.8 dB	32.9 dB	45.5 dB	51.0 dB	66.0 dB	38.5 dB	
3/29/2023 16:10	47.7 dB	33.1 dB	46.5 dB	50.5 dB	60.7 dB	40.0 dB	
3/29/2023 17:10	49.1 dB	38.1 dB	48.0 dB	52.0 dB	63.1 dB	42.5 dB	
3/29/2023 18:10	47.4 dB	34.0 dB	45.5 dB	50.5 dB	65.3 dB	38.5 dB	
3/29/2023 19:10	48.9 dB	35.1 dB	43.5 dB	49.5 dB	71.8 dB	37.5 dB	
3/29/2023 20:10	44.4 dB	33.9 dB	42.0 dB	48.5 dB	56.9 dB	35.5 dB	
3/29/2023 21:10	43.4 dB	33.1 dB	39.0 dB	47.0 dB	65.6 dB	34.5 dB	
3/29/2023 22:10	42.2 dB	33.3 dB	36.5 dB	45.5 dB	61.4 dB	34.5 dB	
3/29/2023 23:10	41.5 dB	33.3 dB	37.0 dB	45.0 dB	56.6 dB	35.0 dB	
3/30/2023 0:00	39.4 dB	34.5 dB	36.5 dB	40.5 dB	60.7 dB	35.0 dB	
3/30/2023 1:00	46.3 dB	34.5 dB	38.0 dB	49.5 dB	69.6 dB	36.0 dB	
3/30/2023 2:00	46.0 dB	36.6 dB	43.5 dB	49.0 dB	61.5 dB	39.0 dB	
3/30/2023 3:00	41.7 dB	35.7 dB	40.0 dB	44.5 dB	55.0 dB	37.5 dB	
3/30/2023 4:00	43.3 dB	36.2 dB	40.5 dB	46.0 dB	60.8 dB	37.5 dB	
3/30/2023 5:00	45.4 dB	36.6 dB	42.5 dB	49.0 dB	64.8 dB	38.0 dB	
3/30/2023 6:00	48.9 dB	36.8 dB	46.5 dB	52.0 dB	68.0 dB	41.0 dB	
3/30/2023 7:00	48.9 dB	37.7 dB	47.5 dB	52.0 dB	61.4 dB	42.5 dB	
3/30/2023 8:00	48.6 dB	38.3 dB	47.0 dB	51.5 dB	62.9 dB	42.5 dB	
3/30/2023 9:00	47.4 dB	38.0 dB	45.5 dB	50.5 dB	61.9 dB	41.0 dB	
3/30/2023 10:00	47.0 dB	36.9 dB	44.5 dB	50.0 dB	67.2 dB	40.0 dB	
3/30/2023 11:00	47.8 dB	36.9 dB	44.0 dB	49.5 dB	73.6 dB	39.5 dB	
3/30/2023 12:00	46.2 dB	36.4 dB	44.0 dB	49.5 dB	58.4 dB	39.5 dB	
3/30/2023 13:00	46.5 dB	36.3 dB	44.5 dB	50.0 dB	61.0 dB	40.0 dB	
3/30/2023 14:00	48.4 dB	36.7 dB	46.0 dB	51.0 dB	64.1 dB	41.0 dB	
3/30/2023 15:00	47.9 dB	38.0 dB	46.5 dB	50.5 dB	60.8 dB	42.0 dB	
3/30/2023 16:00	47.4 dB	36.0 dB	46.0 dB	50.5 dB	67.4 dB	40.0 dB	
3/30/2023 17:00	47.9 dB	36.6 dB	46.5 dB	51.0 dB	61.8 dB	41.5 dB	
3/30/2023 18:00	46.8 dB	35.5 dB	45.0 dB	50.0 dB	62.1 dB	39.0 dB	
3/30/2023 19:00	44.7 dB	33.6 dB	42.5 dB	48.5 dB	65.3 dB	36.0 dB	
3/30/2023 20:00	45.4 dB	33.6 dB	42.5 dB	48.5 dB	63.1 dB	35.5 dB	
3/30/2023 21:00	43.2 dB	33.2 dB	39.5 dB	47.5 dB	58.4 dB	34.0 dB	
3/30/2023 22:00	41.3 dB	33.0 dB	35.5 dB	45.5 dB	58.3 dB	34.0 dB	
3/30/2023 23:00	40.2 dB	32.5 dB	35.0 dB	44.5 dB	56.2 dB	33.5 dB	
3/31/2023 0:00	38.1 dB	32.4 dB	34.0 dB	41.5 dB	53.1 dB	33.0 dB	
3/31/2023 1:00	36.2 dB	32.6 dB	33.5 dB	36.5 dB	54.6 dB	33.0 dB	
3/31/2023 2:00	36.7 dB	32.7 dB	33.5 dB	36.0 dB	56.3 dB	33.0 dB	
3/31/2023 3:00	**37.0 dB**	**33.1 dB**	**34.0 dB**	**38.0 dB**	**54.7 dB**	**33.5 dB**	
3/31/2023 4:00	41.0 dB	33.1 dB	35.0 dB	44.5 dB	59.6 dB	34.0 dB	
3/31/2023 5:00	46.8 dB	34.1 dB	41.0 dB	50.0 dB	69.6 dB	35.5 dB	
3/31/2023 6:00	48.7 dB	36.4 dB	47.0 dB	52.0 dB	62.7 dB	41.0 dB	
3/31/2023 7:00	49.7 dB	38.6 dB	48.5 dB	53.0 dB	61.1 dB	43.0 dB	
3/31/2023 8:00	47.9 dB	35.5 dB	46.0 dB	51.0 dB	64.8 dB	39.5 dB	
3/31/2023 9:00	46.7 dB	36.6 dB	44.5 dB	50.0 dB	60.9 dB	38.5 dB	

3/31/2023 10:00	47.5 dB		44.0 dB	50.5 dB	68.5 dB	38.0 dB
3/31/2023 11:00	46.5 dB	35.1 dB	44.5 dB	49.5 dB	60.6 dB	38.5 dB
3/31/2023 12:00	46.4 dB	34.9 dB	44.5 dB	50.0 dB	59.8 dB	38.0 dB
3/31/2023 13:00	49.9 dB	35.7 dB	45.0 dB	51.0 dB	74.6 dB	39.5 dB

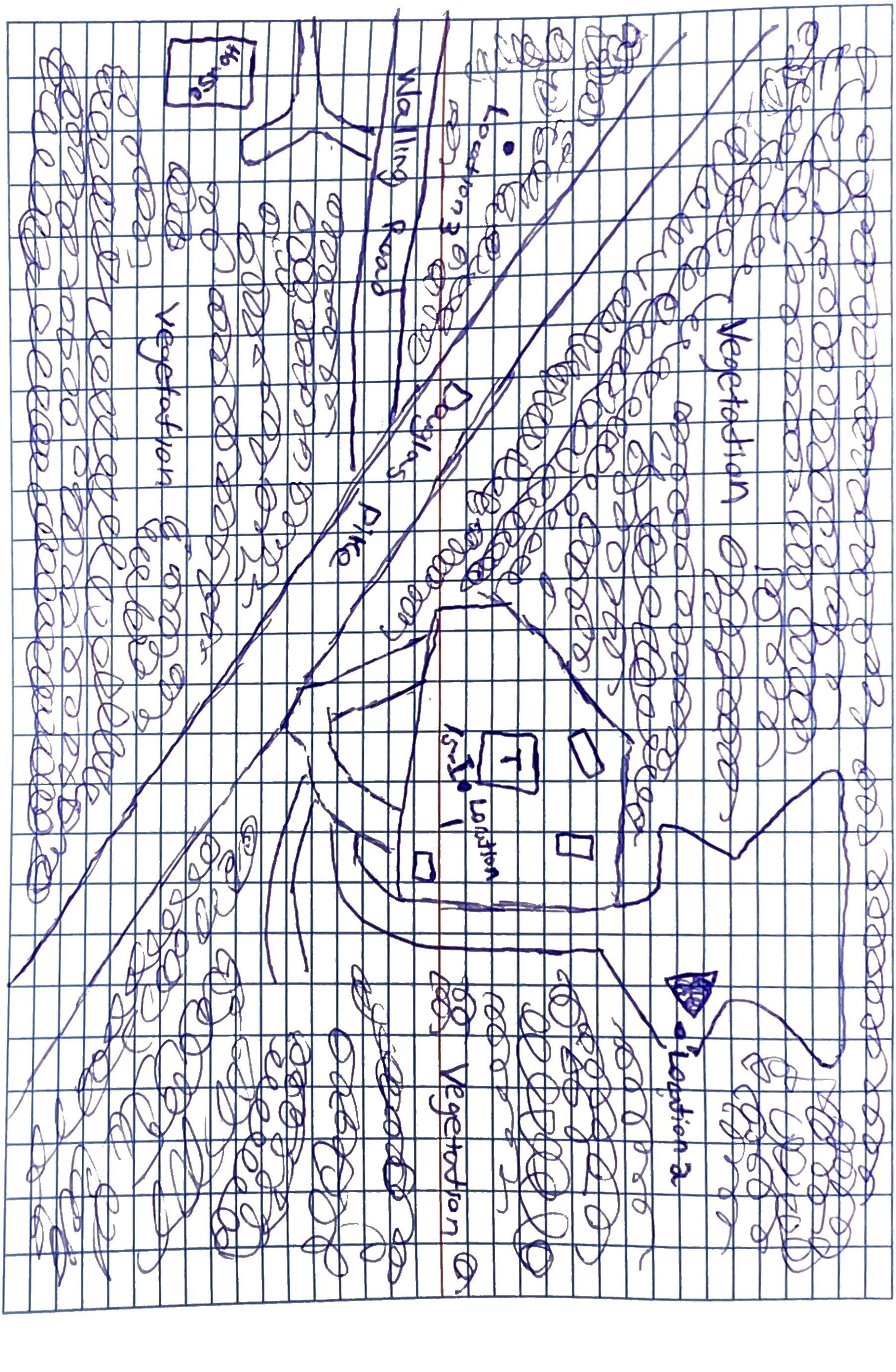
Start Date & Time	LAeq	LASmin	LAS 50%	LAS 10%	LASmax	LAS 90%	Notes
3/29/2023 12:41	60.6 dB	28.5 dB	50.5 dB	62.0 dB	88.5 dB	37.5 dB	
3/29/2023 13:41	59.5 dB	28.4 dB	53.5 dB	63.0 dB	80.4 dB	40.0 dB	
3/29/2023 14:41	59.6 dB	32.0 dB	54.5 dB	63.5 dB	76.5 dB	40.5 dB	
3/29/2023 15:41	59.9 dB	30.9 dB	56.5 dB	63.5 dB	76.5 dB	42.0 dB	
3/29/2023 16:41	60.3 dB	34.7 dB	58.0 dB	64.0 dB	72.3 dB	44.5 dB	
3/29/2023 17:41	58.8 dB	35.3 dB	54.0 dB	63.0 dB	74.8 dB	42.5 dB	
3/29/2023 18:41	58.4 dB	28.8 dB	50.5 dB	61.5 dB	82.6 dB	38.5 dB	
3/29/2023 19:41	56.8 dB	31.5 dB	47.0 dB	60.5 dB	80.9 dB	36.0 dB	
3/29/2023 20:41	53.6 dB	29.5 dB	44.0 dB	59.0 dB	68.3 dB	33.5 dB	
3/29/2023 21:41	52.1 dB	28.1 dB	38.5 dB	57.0 dB	70.3 dB	31.0 dB	
3/29/2023 22:41	50.1 dB	28.9 dB	35.5 dB	53.0 dB	67.6 dB	30.5 dB	
3/29/2023 23:41	48.5 dB	28.4 dB	32.5 dB	46.0 dB	69.7 dB	29.5 dB	
3/30/2023 0:00	47.7 dB	27.9 dB	32.0 dB	43.5 dB	71.5 dB	29.5 dB	
3/30/2023 1:00	46.2 dB	27.3 dB	37.0 dB	48.0 dB	67.0 dB	30.0 dB	
3/30/2023 2:00	50.0 dB	34.2 dB	44.0 dB	52.0 dB	71.0 dB	39.0 dB	
3/30/2023 3:00	47.3 dB	31.9 dB	39.0 dB	44.0 dB	69.6 dB	35.0 dB	
3/30/2023 4:00	52.3 dB	32.8 dB	40.0 dB	54.5 dB	72.2 dB	35.5 dB	
3/30/2023 5:00	57.0 dB	32.0 dB	45.5 dB	61.5 dB	79.5 dB	36.0 dB	
3/30/2023 6:00	**61.8 dB**	**35.9 dB**	**54.5 dB**	**65.0 dB**	**86.8 dB**	**42.5 dB**	
3/30/2023 7:00	60.9 dB	38.0 dB	57.0 dB	65.0 dB	77.7 dB	44.0 dB	
3/30/2023 8:00	59.7 dB	39.0 dB	53.5 dB	63.5 dB	77.3 dB	43.0 dB	
3/30/2023 9:00	57.9 dB	37.1 dB	49.5 dB	62.5 dB	76.0 dB	41.5 dB	
3/30/2023 10:00	58.1 dB	34.5 dB	48.0 dB	61.5 dB	80.5 dB	41.0 dB	
3/30/2023 11:00	58.2 dB	34.5 dB	48.0 dB	61.0 dB	84.1 dB	39.5 dB	
3/30/2023 12:00	57.4 dB	32.6 dB	49.0 dB	61.5 dB	72.5 dB	39.5 dB	
3/30/2023 13:00	57.6 dB	31.7 dB	49.0 dB	61.5 dB	79.6 dB	39.5 dB	
3/30/2023 14:00	59.3 dB	33.0 dB	53.0 dB	62.5 dB	77.6 dB	41.5 dB	
3/30/2023 15:00	59.0 dB	37.4 dB	53.5 dB	62.5 dB	76.4 dB	43.0 dB	
3/30/2023 16:00	59.0 dB	34.2 dB	55.0 dB	63.0 dB	75.9 dB	42.0 dB	
3/30/2023 17:00	59.3 dB	35.7 dB	56.5 dB	63.0 dB	72.3 dB	43.5 dB	
3/30/2023 18:00	58.2 dB	32.5 dB	51.5 dB	62.5 dB	77.9 dB	39.5 dB	
3/30/2023 19:00	56.6 dB	28.1 dB	49.5 dB	61.5 dB	74.1 dB	36.5 dB	
3/30/2023 20:00	55.8 dB	28.9 dB	48.0 dB	61.0 dB	70.2 dB	34.5 dB	
3/30/2023 21:00	54.4 dB	27.0 dB	43.0 dB	59.5 dB	70.7 dB	30.5 dB	
3/30/2023 22:00	51.6 dB	26.1 dB	37.0 dB	55.5 dB	69.0 dB	29.0 dB	
3/30/2023 23:00	50.7 dB	25.3 dB	35.0 dB	53.5 dB	70.9 dB	27.0 dB	
3/31/2023 0:00	**47.9 dB**	**25.3 dB**	**30.0 dB**	**46.0 dB**	**66.0 dB**	**27.0 dB**	
3/31/2023 1:00	44.9 dB	25.2 dB	28.0 dB	39.0 dB	68.2 dB	26.5 dB	
3/31/2023 2:00	46.8 dB	25.9 dB	28.5 dB	39.5 dB	71.0 dB	27.0 dB	
3/31/2023 3:00	46.0 dB	25.7 dB	28.5 dB	40.5 dB	68.7 dB	27.0 dB	
3/31/2023 4:00	52.2 dB	26.6 dB	34.5 dB	52.5 dB	73.3 dB	29.0 dB	
3/31/2023 5:00	57.6 dB	30.0 dB	45.0 dB	61.5 dB	79.9 dB	35.0 dB	
3/31/2023 6:00	60.5 dB	36.2 dB	54.5 dB	64.5 dB	76.2 dB	43.0 dB	
3/31/2023 7:00	63.8 dB	37.2 dB	58.0 dB	65.0 dB	93.2 dB	45.5 dB	
3/31/2023 8:00	59.0 dB	29.3 dB	53.5 dB	63.0 dB	74.4 dB	39.0 dB	
3/31/2023 9:00	58.4 dB	27.1 dB	52.0 dB	62.5 dB	75.0 dB	38.5 dB	

3/31/2023 10:00	57.5 dB	27.4 dB	49.5 dB	62.0 dB	73.6 dB	37.0 dB
3/31/2023 11:00	58.6 dB	32.3 dB	50.5 dB	62.0 dB	77.8 dB	38.0 dB
3/31/2023 12:00	58.1 dB	30.4 dB	51.0 dB	62.0 dB	76.8 dB	38.5 dB
3/31/2023 13:00	59.1 dB	31.6 dB	52.5 dB	62.5 dB	79.6 dB	39.5 dB
3/31/2023 14:00	78.6 dB	42.1 dB	56.0 dB	65.0 dB	103.2 dB	48.0 dB

03/29/23 445 Douglas Turnpike, Burriville, RI

- Personnel: CD
- Scope: Noise meter dropoff
- Weather: 50s, sunny
- Depart: 7:20
- Arrive: 11:45
- Three noise meter locations, ~~#~~ 48-hr sessions.
- Met with John onsite.
- Location 1 meter # 1488256.
- Location 1 Cal. # 4478708.
- Location 1 is in the fenced-in area, next to a large transformer.
- Location 1 precal. at 11:58
- Location 1 start at 12:00
- Location 2 meter # 5086866.
- Location 2 Cal. # 1090999.
- Location 2 is down the first dirt path on the left.
- Location 2 precal. at 12:08
- Location 2 start at 12:09
- Location 3 meter # 4273006
- Location 3 Cal. # 357428
- Location 3 is between Walling Road and Douglas Turnpike, 50 feet off ~~t~~ each road.

- Location 3 precal. at 12:38
- Location 3 start at 12:41
- John departs at 12:43.
- Additional site photos are taken.
- Shawn Martin will pickup meters on Friday, ~~[illegible]~~ March 31st.
- Depart: 13:10
- Arrived at 17:40


Walling Road
Douglas Pike
Vegetation
Vegetation
Vegetation
Vegetation
Location 1
Location 2
Location 3

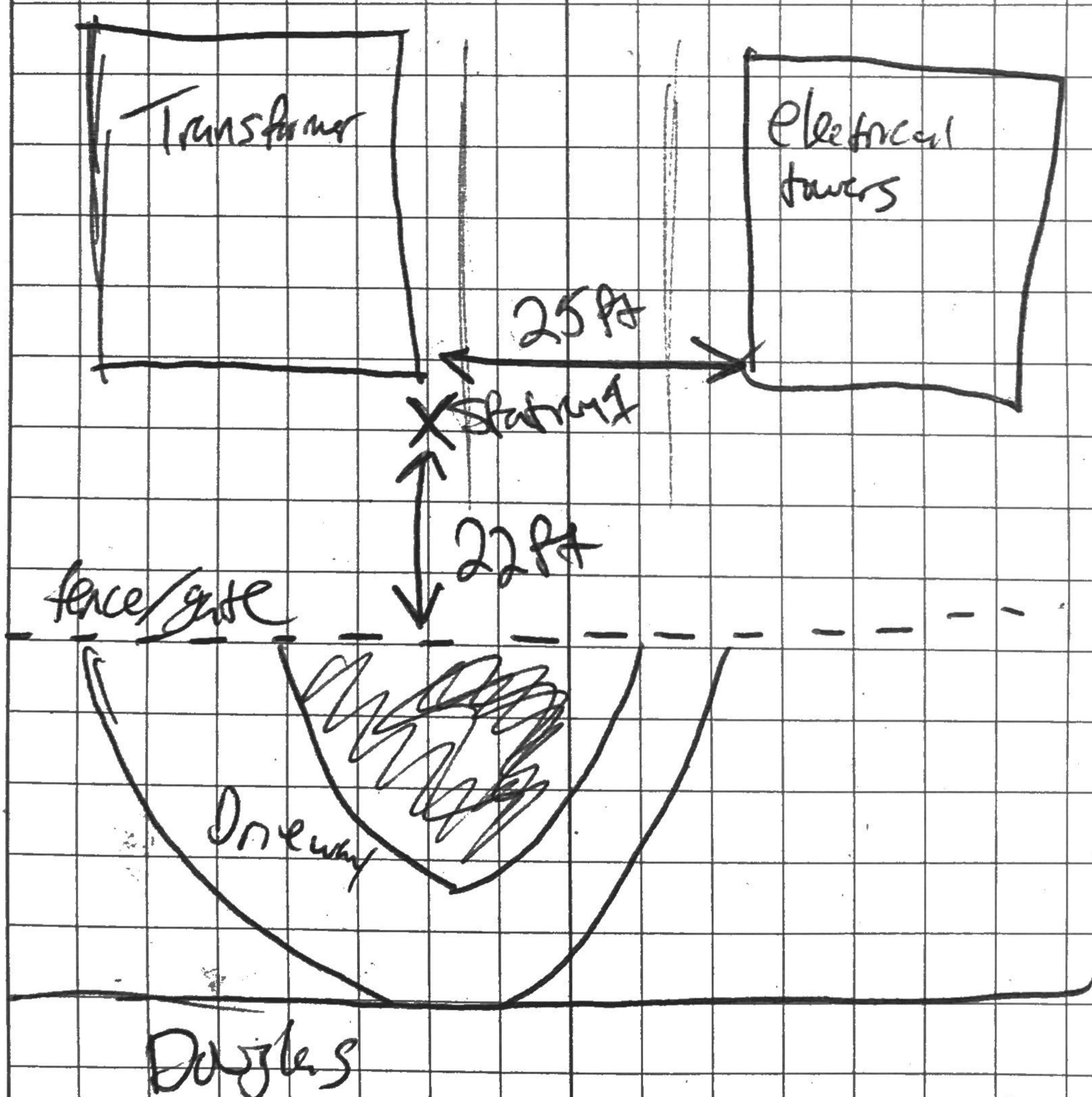
Location 445 Douglas Pike, RI Date 3-31-23

Project / Client Nasonville Substation, Noise Monitoring

Shawn Martin # 03.0035174.00

12:40 - arrived on site
- Checked in

1300 - Began break down of Station 1
Station 1 location sketch



1310 - Began break down of Station 1
- Calibrated meter to 114 Db with # 4478108

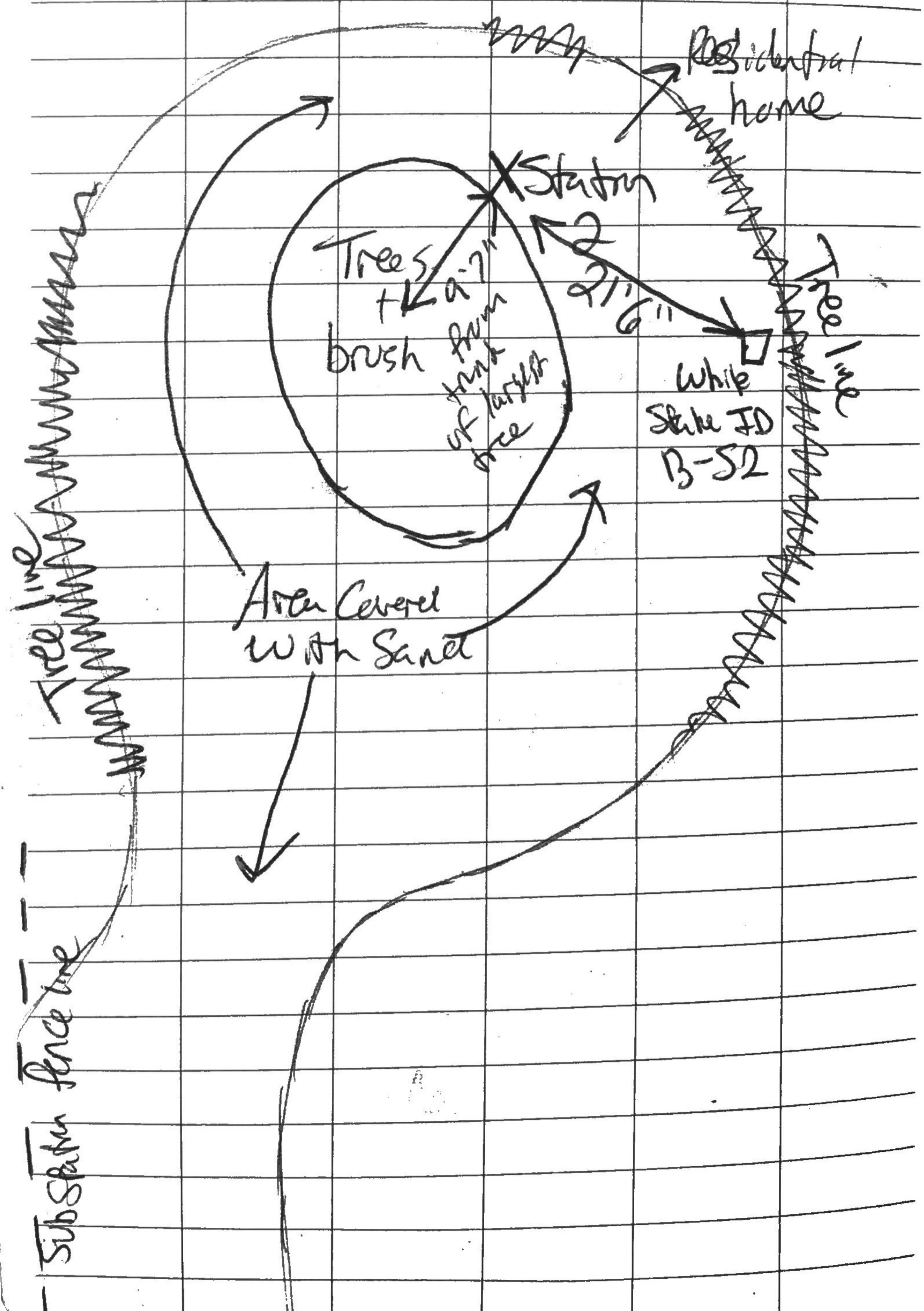
1325 - Completed Station 1 breakdown

112 Location 445 Douglas Pike, RI Date 3-31-23

Project / Client Nasonville Substation

Shaun Martin 03.0035174.02

1327: location 2 Sketch



Location 445 Douglas Pike, RI Date 3-31-23 113

Project / Client Nasonville Substation

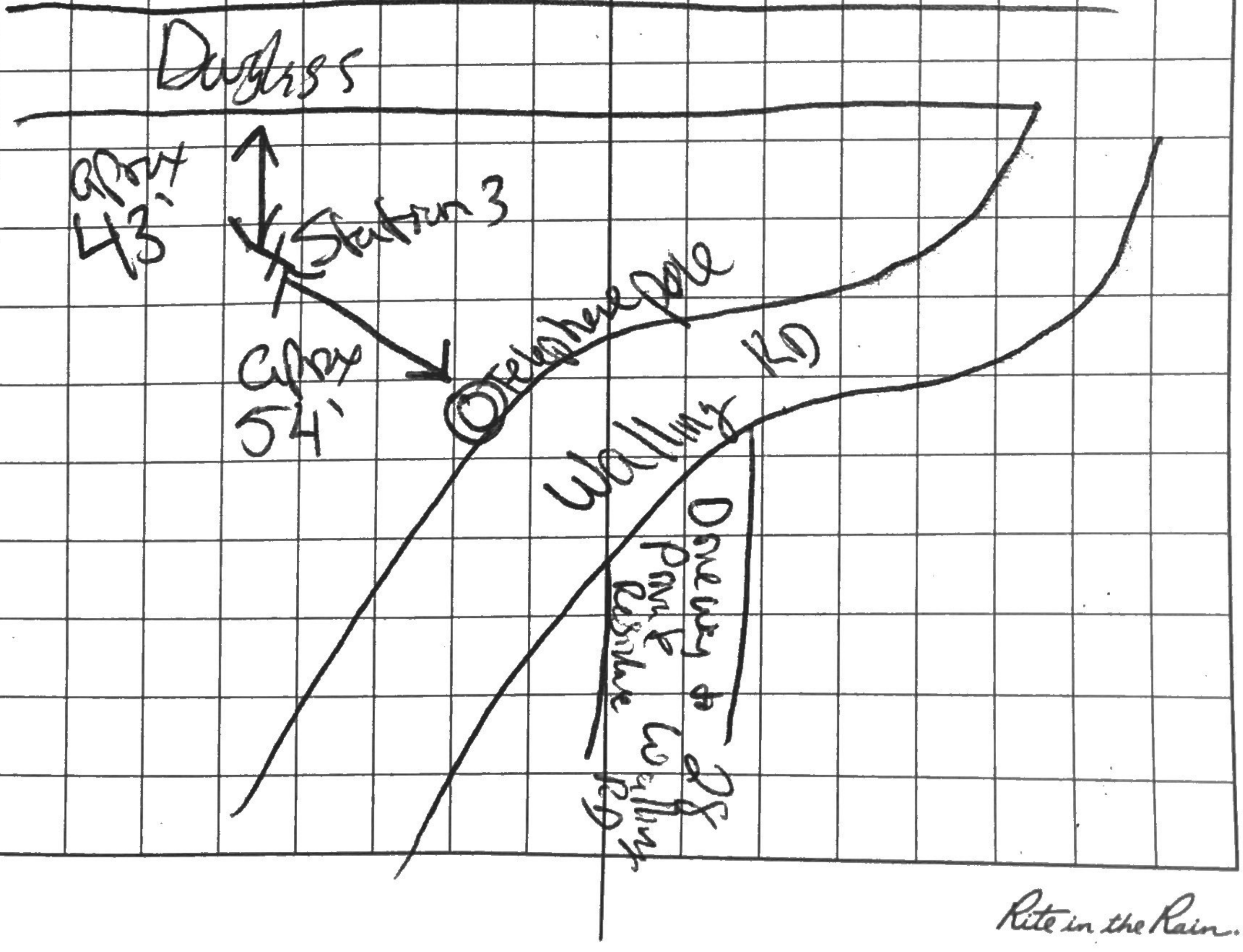
Shawn Martin 03 00351702

1335 - Began Stat 2 Drawdown
- Attempted to Calibrate to 114 dB
- first attempt failed, reading 66.3 dB
- Second attempt failed, reading 60.5 dB - Calibrator # 1090999
- Called Christian, will re-attemp Calibration with ~~Meter~~ Calibrator # 4478708

1340 - Station 2 passed Calibration using Calibrator 4478708

1350 - Completed Station 2 Drawdown

1355 - Station 3 Sketch



Location 445 Douglas Pike, RI Date 3-31-23

Project / Client Nasonville Substation

Shawn Martin 03.00

1405- began breakdown of Station 3
- Calibrated Station 3 using Calibrator
#3574248
- passed Calibration on attempt 1
1420- Completed breakdown of Station 3
- will return to transformer to collect
1 30 sec reading from each side
1425- unable to collect 30 second readings,
Site gates have been locked and attendant
has left
1430- all equipment packed, Shawn M leaving
Site.
18:45- arrived at NNS office
1900- equipment unloaded
- end of work SM

www.casellasolutions.com CASELLA

Certificate of Conformity and Calibration

Instrument Model:-	**CEL-633C**		
Serial Number	1488256		
Firmware revision	V006-05		
Microphone Type:-	**CEL-251**	**Preamplifier Type:-**	**CEL-495**
Serial Number	3796	Serial Number	**004208**
Instrument Class/Type:-	**1**		

Applicable standards:-

IEC 61672: 2013 / EN 60651 (Electroacoustics - Sound Level Meters)
IEC 60651 1979 (Sound Level Meters), ANSI S1.4: 1983 (Specifications For Sound Level Meters)

Note:- The test sequences performed in this report are in accordance with the current Sound level meter *Standard - IEC61672. The combination of tests performed are considered to confirm the products electro-acoustic performance to all applicable standards including superceeded Sound Level Meter Standards - IEC60651 and IEC60804.*

Test Conditions:-	25 °C	**Test Engineer:-**	Paul Blackwell
	38 %RH	**Date of Issue:-**	July 27, 2022
	1015 mBar		

Declaration of conformity:-

This test certificate confirms that the instrument specified above has been successfully tested to comply with the manufacturer's published specifications. Tests are performed using equipment traceable to national standards in accordance with Casella's ISO 9001:2015 quality procedures. This product is certified as being compliant to the requirements of the CE Directive.

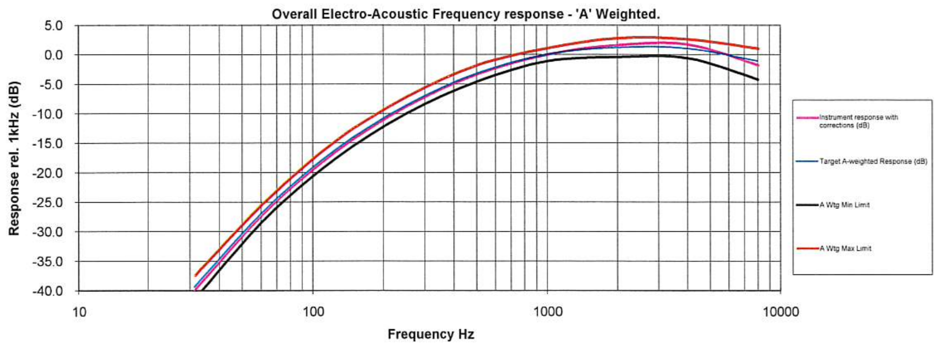
Test Summary:-

Self Generated Noise Test	**All Tests Pass**
Electrical Signal Test Of Frequency Weightings	**All Tests Pass**
Frequency & Time Weightings At 1 kHz	**All Tests Pass**
Level Linearity On The Reference Level Range	**All Tests Pass**
Toneburst Response Test	**All Tests Pass**
C-peak Sound Levels	**All Tests Pass**
Overload Indication	**All Tests Pass**
Acoustic Tests	**All Tests Pass**

Combined Electro-Acoustic Frequency Response - A Weighted

Combined Electro-Acoustic Frequency Response - A Weighted (IEC 61672-3:2006)

The following A-Weighted frequency response graph shows this instruments overall frequency response based upon the application of multi-frequency pressure field calibrations. The microphones Pressure to Free field correction coefficients are applied to pressure response. Reference level taken at 1kHz.



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Email: info@casellasolutions.cn

Tested to CEL-63X test sheet TP444 revision 02-00

www.casellasolutions.com **CASELLA**

Certificate of Conformity and Calibration

Instrument Model:-	**CEL-633C**		
Serial Number	4278006		
Firmware revision	V006-05		
Microphone Type:-	**CEL-251**	**Preamplifier Type:-**	**CEL-495**
Serial Number	4372	Serial Number	005389
Instrument Class/Type:-	1		

Applicable standards:-

IEC 61672: 2013 / EN 60651 (Electroacoustics - Sound Level Meters)
IEC 60651 1979 (Sound Level Meters), ANSI S1.4: 1983 (Specifications For Sound Level Meters)

Note:- The test sequences performed in this report are in accordance with the current Sound level meter *Standard - IEC61672. The combination of tests performed are considered to confirm the products electro-acoustic performance to all applicable standards including superceeded Sound Level Meter Standards - IEC60651 and IEC60804.*

Test Conditions:-

25 °C		**Test Engineer:-**	Paul Blackwell
38 %RH		**Date of Issue:-**	July 27, 2022
1015 mBar			

Declaration of conformity:-

This test certificate confirms that the instrument specified above has been successfully tested to comply with the manufacturer's published specifications. Tests are performed using equipment traceable to national standards in accordance with Casella's ISO 9001:2015 quality procedures. This product is certified as being compliant to the requirements of the CE Directive.

Test Summary:-

Self Generated Noise Test	**All Tests Pass**
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Combined Electro-Acoustic Frequency Response - A Weighted

Combined Electro-Acoustic Frequency Response - A Weighted (IEC 61672-3:2006)

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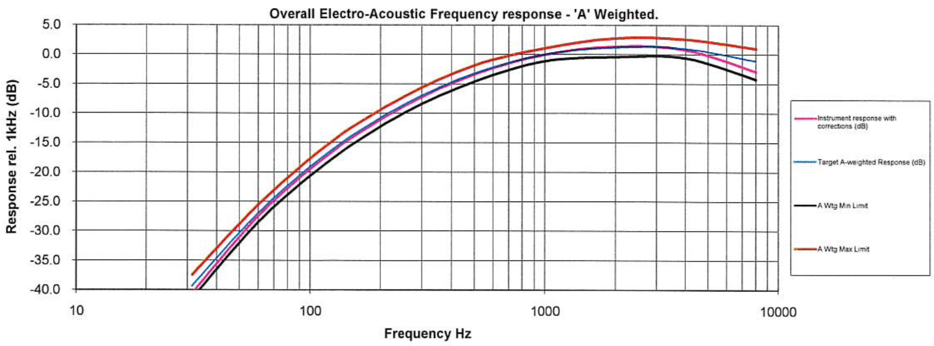

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Tested to CEL-63X test sheet TP444 revision 02-00

www.casellasolutions.com CASELLA

Certificate of Conformity and Calibration

Instrument Model:-	**CEL-633C**		
Serial Number	5086866		
Firmware revision	V006-05		
Microphone Type:-	**CEL-251**	**Preamplifier Type:-**	**CEL-495**
Serial Number	2268	Serial Number	003810
Instrument Class/Type:-	1		

Applicable standards:-

IEC 61672: 2013 / EN 60651 (Electroacoustics - Sound Level Meters)
IEC 60651 1979 (Sound Level Meters), ANSI S1.4: 1983 (Specifications For Sound Level Meters)

Note:- The test sequences performed in this report are in accordance with the current Sound level meter *Standard - IEC61672. The combination of tests performed are considered to confirm the products electro-acoustic performance to all applicable standards including superceeded Sound Level Meter Standards - IEC60651 and IEC60804.*

Test Conditions:-	25 °C	**Test Engineer:-**	Paul Blackwell
	38 %RH	**Date of Issue:-**	July 27, 2022
	1015 mBar		

Declaration of conformity:-

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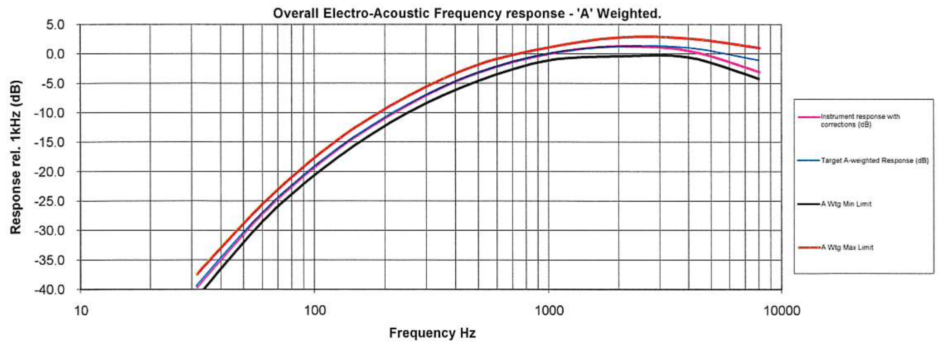

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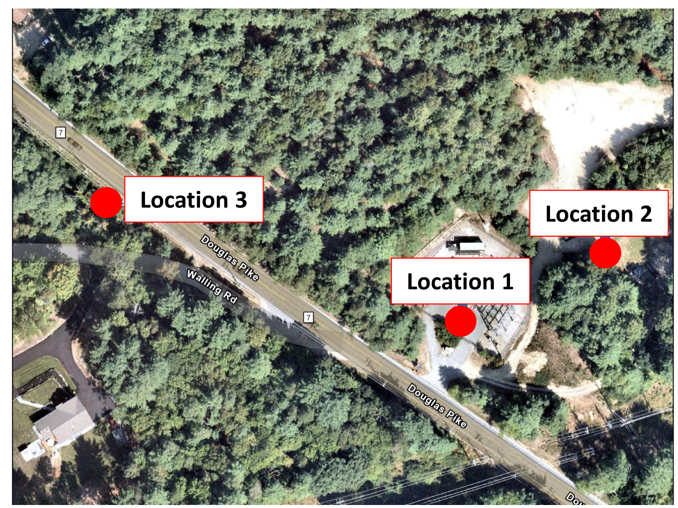
Tested to CEL-63X test sheet TP444 revision 02-00

1 Location 1

2 Location 2

3 Location 3



Aerial of project area

Attachment C – Limitations

USE OF REPORT

1. GZA GeoEnvironmental, Inc. (GZA) has prepared this report on behalf of, and for the exclusive use of Client for the stated purpose(s) and location(s) identified in the Report. Use of this report, in whole or in part, at other locations, or for other purposes, may lead to inappropriate conclusions; and we do not accept any responsibility for the consequences of such use(s). Further, reliance by any party not identified in the agreement, for any use, without our prior written permission, shall be at that party's sole risk, and without any liability to GZA.

STANDARD OF CARE

2. The conclusions presented in this report were based solely upon the services described in this report, and not on scientific tasks or procedures beyond the scope of described services or the time and budgetary constraints imposed by Client. Conditions at the facility are subject to change, therefore the compliance status at any given time could differ from the status at the time of ourreport.

3. This report describes the compliance status with respect to the environmental regulatory program(s) outlined in the report. Compliance with regulatory programs or specific regulatory requirements other than the program(s) outlined in this report have not been evaluated.

4. Information pertaining to the facility, structures, and operations and activities conducted at the facility was provided to GZA by Client as indicated within the report. In performing the services described oin the report, GZA has relied on the information provided by Client, including the accuracy and completeness thereof.

5. The purpose of this study was to review the regulatory compliance of current operations and activities conducted at the facility within the limits of the objective and scope of work described in our proposal and/or report. We did not attempt to assess the compliance status of present or past owners or operators of the facility.

6. Unless otherwise specified in the report, GZA did not perform testing or analyses to determine the presence or concentration of any chemicals, oils, asbestos, or polychlorinated biphenyls at the site, within site buildings, or in the environment at the site. Where such analyses have been conducted by an outside laboratory, GZA has relied upon the data provided, and has not conducted an independent evaluation of the reliability of these data.

COMPLIANCE WITH CODES AND REGULATIONS

7. The regulatory compliance status described in this report has been evaluated based on our interpretation of regulations, and where appropriate, the interpretations provided by the applicable regulatory authority personnel at the time of our study. In some cases, these interpretations require subjective judgment and we cannot guarantee that all applicable regulatory authority personnel will interpret the regulations in the same manner as we have, or in the manner that the agency personnel we may have spoken to have. Applicable regulatory authorities' interpretations, requirements, and enforcement policies vary from district office to district office, from state to state, and between federal and state agencies. In addition, statues, rules, standards, and regulations may be legislatively changed and inter-agency and intra-agency policies may be changed from present practices from time to time.

8. In preparing this report, GZA has relied on certain information provided by federal, State, or local applicable regulatory authorities and other parties referenced herein, and on information contained in the files of federal, State, and/or local applicable regulatory authorities available to GZA at the time of our compliance study. Although there may have been some degree of overlap in the information provided by these various sources, GZA did not attempt to independently verify the accuracy or completeness of all information reviewed or received during the course of the study. Where information provided by Client was not complete, representations regarding the regulatory compliance of such operations and activities has not been made.

INTERPRETATION OF DATA

9. GZA's work was performed in accordance with generally accepted practices of other consultants undertaking similar studies at the same time and in the same geographical area, and GZA observed that degree of care and skill generally exercised by other consultants under similar circumstances and conditions. GZA's findings and conclusions must be considered not as scientific certainties, but rather as our professional opinion concerning the significance of the limited data gathered during the course of the study. No warranty, express or implied, is made. Specifically, GZA does not and cannot represent that the Site contains no hazardous material, oil, or other latent condition beyond that observed by GZA during its study. Additionally, GZA makes no warranty that any response action or recommended action will achieve all of its objectives or that the findings of this study will be upheld by an applicable regulatory authority.

NEW INFORMATION

10. In the event that the Client or others authorized to use this report obtain information on environmental regulatory compliance issues at the facility not contained in this report, such information shall be brought to GZA's attention forthwith. GZA will evaluate such information and, on the basis of this study, may modify the conclusions stated in this report.

This document is to justify the purchase of the home behind the Nasonville Substation.

I obtained an estimate from our Noise Study consultant for the sound barriers that would be required to meet the Town of Burrillville Noise code with the additional transformer at Nasonville. This estimate is from a similar project (sound barrier height and length) and was **$232,139.97** for the design and materials. This estimate was obtained from the consultant who performed the Nasonville Substation Sound Study. Based on this estimate and the "Distribution Actuals for Calendar Year 2023" breakdown table for substations below, the total cost of the sound wall would be **$619,370.**

Project Type2	Summarized Description	Percent of Actuals
OH Line	AFUDC	1.42%
	Construction	61.62%
	Materials	22.08%
	Overheads	14.88%
OH Line Total		**51.87%**
Substation	AFUDC	3.83%
	Construction	46.30%
	Materials	37.48%
	Overheads	12.40%
Substation Total		**34.50%**
UG Line	AFUDC	5.04%
	Construction	64.97%
	Materials	9.13%
	Overheads	20.86%
UG Line Total		**9.05%**
URD	AFUDC	3.35%
	Construction	71.97%
	Overheads	24.68%
URD Total		**4.58%**
Grand Total		**100.00%**

We have not gone through the Town's Noise Variance hearings yet. Obviously, there is a cost for legal, etc. to obtain this variance through a few meetings and hearings. We can estimate around **$20,000** for this effort**.** In addition, the Town is looking for us to provide landscaping for the homeowner. Landscaping to cover a sound wall and screen the home of this size wall and the substation could be over **$100,000**.

The project will also require a second 115kV line into the substation (temporary T Line Tap) for the second transformer and bay. Additional rights will be required from the landowner to cut trees and build the overhead line tap. In addition, there is a project in Project Development that will refurbish the current B23 (Woonsocket-Nasonville) transmission line and require additional rights from the landowners, one being the owner of this house. These rights could cost up to **$25,000.** In total the estimates described above will be a little over **$764K.**

There are some other items that are difficult to quantify, but are liability concerns, such as dual ownership of the access road to the substation with this landowner. The home is essentially landlocked by the Nasonville substation making maintenance activities at the substation and future construction activities liable for issues that could arise. The home could also be used as a project office for the next few phases of the project saving the project additional funds from bringing in project office trailers.

Another new landowner would purchase this home with ongoing construction at the Nasonville substation, not seeing the finished substation. Once the substation construction is finished a year or more from now will provide a very different view than what they would see today. We could be in for legal battles with this landowner for activities that we do in the ROW or substation in the future.

Sound Wall Breakdown Analysis

AFUDC	3.83%	$	23,721.88	3.83%
Construction	46.30%	$	286,768.43	46.30%
Materials	37.48%	$	232,139.97	37.48%
Overheads	12.40%	$	76,801.91	12.40%
		$	**619,370.25**	
Overall Cost for design & materials			$232,139.97	

Division 1-55
System Capacity & Performance

Request:

For each Separately Tracked Major Project, excluding Dyer Street and Southeast Substation, provide the anticipated date that the Company will complete a detailed construction schedule and produce a construction grade estimate (+/-10%). Provide all detailed construction schedules completed to date.

Response:

The table below sets forth the anticipated date that the Company will complete detailed construction schedules and construction grade estimates for each project.

The Company is providing the detailed construction schedule for the Nasonville Substation Expansion project as Attachment DIV 1-55. The remainder of the projects do not yet have detailed construction schedules.

	(a)	(b)	(c)
	Project Name	Date for Detailed Construction Schedule	Date for Construction Grade Estimate (+/- 10%)
1	Admiral St	August 2025	December 2025
2	Apponaug	November 2025	May 2026
3	Phillipsdale	November 2025	May 2026
4	Auburn	July 2026	October 2027
5	Hospital	March 2027	June 2028
6	Kingston	July 2026	October 2026
7	Merton	July 2026	October 2026
8	East Providence	July 2025	October 2025
9	Nasonville	June 2024	December 2024
10	Chase Hill	July 2026	October 2026
11	New Lafayette	March 2025	May 2025
12	Warren	March 2025	May 2025

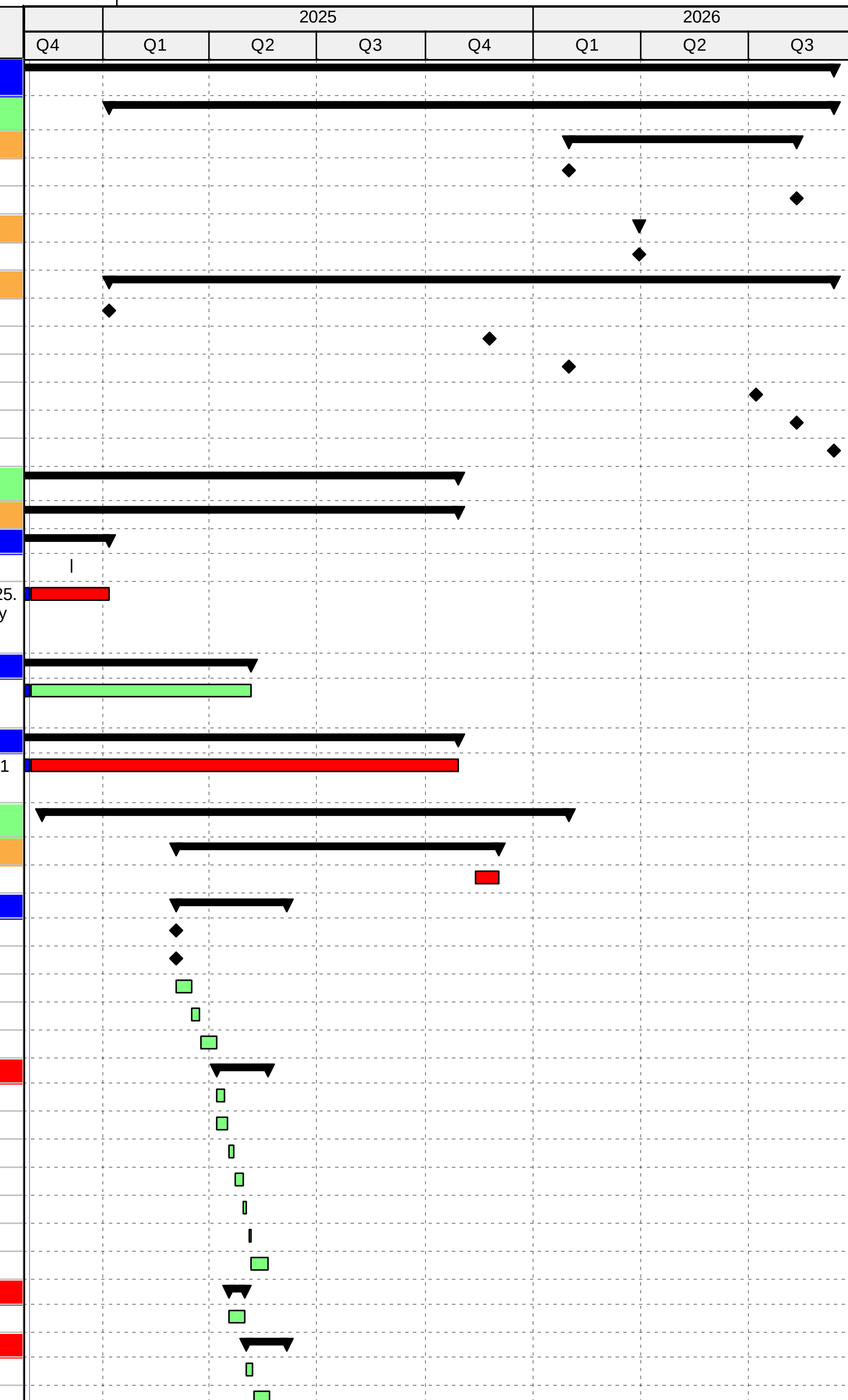
Prepared by or under the supervision of: Daniel Glenning

BURNS & McDONNELL

CRI3027 Nasonville #127 Substation Expansion Project DSUB CRI3027
Project Schedule

Generated on: Nov-20-2024

#	Activity ID	Activity Name	Original Duration	Start	Finish	Comments
1	**Nasonville #127 Substation Expansion Project DSUB CRI3027**		792d	Aug-22-2023 A	Sep-11-2026	
2	**Milestones**		429d	Jan-7-2025	Sep-11-2026	
3	**Gate Milestones (Scheduled)**		135d	Jan-30-2026	Aug-11-2026	
4	G4	Gate 4 (Scheduled In Service) (Nasonville D-Sub Exp.)	0d		Jan-30-2026	
5	G5	Gate 5 (Project Closure Validation) (Nasonville D-Sub Exp.)	0d		Aug-11-2026	
6	**Gate Milestones (Required)**		0d	Mar-31-2026	Mar-31-2026	
7	GDR	Gate 4 (Required In Service) (Nasonville D-Sub Exp.)	0d		Mar-31-2026*	
8	**Project Milestones**		429d	Jan-7-2025	Sep-11-2026	
9	CS	CS (Construction Start) (Nasonville D-Sub Exp.)	0d		Jan-7-2025	
10	CC	CC (Construction Complete) (Nasonville D-Sub Exp.)	0d		Nov-24-2025	
11	RFL	RFL (Ready For Load) (Nasonville D-Sub Exp.)	0d		Jan-30-2026	
12	ABC	ABC (As-Builts Complete) (Nasonville D-Sub Exp.)	0d		Jul-7-2026	
13	FC	FC (Financial Closed) (Nasonville D-Sub Exp.)	0d		Aug-11-2026	
14	PC	Project Closed (Nasonville D-Sub Exp.)	0d		Sep-11-2026	
15	**Procurement**		572d	Aug-22-2023 A	Oct-29-2025	
16	**Long Lead Material**		572d	Aug-22-2023 A	Oct-29-2025	
17	**115-13.8kV Tranformer Procurement**		345d	Aug-22-2023 A	Jan-6-2025	
18	LLM1910	FAT (Factory Acceptance Test) (Transformer) (Nasonville D-Sub Exp.)	1d	Dec-6-2024	Dec-6-2024*	10.21 - confirmed 12/6/24
19	MM1080	Fabrication and Delivery of Material (Transformer) (Nasonville D-Sub Exp.)	336d	Aug-22-2023 A	Jan-6-2025	9.23 - Manufacturer delay - pushed to 1/25. PTT Quanta = 336d = 16 Dec '24 Delivery
20	**Voltage Regulators**		340d	Jan-10-2024 A	May-6-2025	
21	MM1170	Fabrication and Delivery of Material (Voltage Regulators) (Nasonville D-Sub Exp.)	340d	Jan-10-2024 A	May-6-2025	Siemens 68 Wks/340d. PO - 40000001019 - DIST Rev 0, shows
22	**Cap Banks**		275d	Oct-7-2024 A	Oct-29-2025	
23	MM1100	Fabrication and Delivery of Material (Cap Banks) (Nasonville D-Sub Exp.)	275d	Oct-7-2024 A	Oct-29-2025	55 Wks LT = 275D - Not Preventing Bus 1 - North Side - from Being energized.
24	**Construction**		315d	Nov-11-2024 A	Jan-30-2026	
25	**Civil Construction**		192d	Mar-4-2025	Dec-2-2025	
26	A1320	Install Perimeter Fence - PH2 (Nasonville D-Sub Exp.)	13d	Nov-13-2025	Dec-2-2025	
27	**United Civil - Phase 2 Construction Schedule**		68d	Mar-4-2025	Jun-6-2025	
28	50	NTP from RIE	0d	Mar-4-2025*		
29	51	Mobilize	0d	Mar-4-2025		
30	52	Demo & Prep	10d	Mar-4-2025	Mar-17-2025	
31	53	Cut/Fills	5d	Mar-18-2025	Mar-24-2025	
32	54	Retaining Wall #1	10d	Mar-25-2025	Apr-7-2025	
33	**Foundations**		31d	Apr-8-2025	May-20-2025	
34	62	TF4 Drilled Shafts	5d	Apr-8-2025	Apr-14-2025	
35	56	P4 Foundations	8d	Apr-8-2025	Apr-17-2025	
36	57	RS4	3d	Apr-18-2025	Apr-22-2025	
37	58	CBSA	5d	Apr-23-2025	Apr-29-2025	
38	59	P33A	3d	Apr-30-2025	May-2-2025	
39	60	TPCP	2d	May-5-2025	May-6-2025	
40	61	ST2A - Trans 2	10d	May-7-2025	May-20-2025	
41	**Duct Bank**		10d	Apr-18-2025	May-1-2025	
42	64	Conduit Sweeps to P4	10d	Apr-18-2025	May-1-2025	
43	**Finishes**		25d	May-2-2025	Jun-6-2025	
44	66	Grounding	5d	May-2-2025	May-8-2025	
45	67	Yard Conduits	10d	May-9-2025	May-22-2025	



Actual Work — Critical Remaining Work — Summary
Remaining Work — Milestone

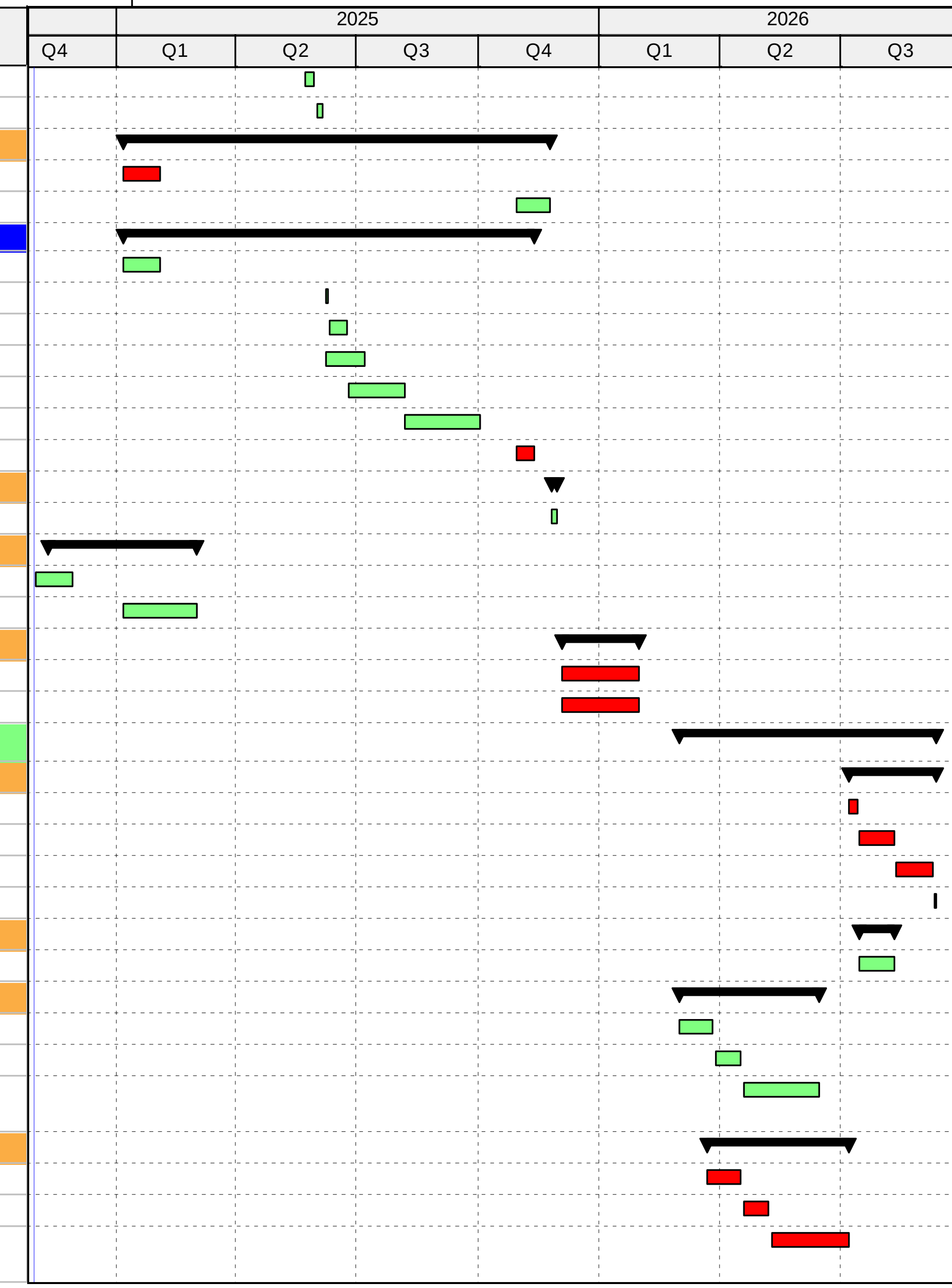
Nov-20-2024 15:57

BURNS McDONNELL

CRI3027 Nasonville #127 Substation Expansion Project DSUB CRI3027
Project Schedule

Generated on: Nov-20-2024

#	Activity ID	Activity Name	Original Duration	Start	Finish	Comments
46	68	Stone Infiltration Trenches	5d	May-23-2025	May-30-2025	
47	69	Station Stone	5d	Jun-2-2025	Jun-6-2025	
48	**Substation Construction**		227d	Jan-7-2025	Nov-24-2025	
49	A1330	Install Transformer (Nasonville D-Sub Exp.)	20d	Jan-7-2025	Feb-3-2025	
50	CONW1000	Install Open Air Breaker System (Nasonville D-Sub Exp.)	18d	Oct-30-2025	Nov-24-2025	
51	**Electrical Construction - Phase 2**		219d	Jan-7-2025	Nov-12-2025	
52	CONW1040	Transformer - Set & Install (Nasonville DSUB - Exp)	20d	Jan-7-2025	Feb-3-2025	
53	CONW1080	O&M Mobilize for Phase 2 (Nasonville D-Sub Exp.)	2d	Jun-9-2025	Jun-10-2025	After Phase 2 Civil Completed
54	CONW1060	Install Regulators (Nasonville D-Sub Exp.D)	10d	Jun-11-2025	Jun-24-2025	
55	A38960	Install Circuit Breakers (Nasonville D-Sub Exp.)	20d	Jun-9-2025	Jul-7-2025	
56	CONW1070	Install Load Brk & Circuit Switcher (Nasonville D-Sub Exp.)	30d	Jun-25-2025	Aug-6-2025	
57	CONW1030	Pull & Term Cables (Nasonville D-Sub Exp.)	40d	Aug-7-2025	Oct-2-2025	
58	CONW1020	Install Cap Bank (Nasonville D-Sub Exp.D)	10d	Oct-30-2025	Nov-12-2025	
59	**Outages**		5d	Nov-25-2025	Nov-29-2025	
60	OUTAGES1000	Outages (Nasonville D-Sub Exp.)	5d	Nov-25-2025	Nov-29-2025	
61	**Demo / Removal**		83d	Nov-11-2024 A	Mar-3-2025	
62	A38970	Remove and Return Mobile Switchgear (Nasonville D-Sub Exp.)	5d	Nov-11-2024 A	Nov-29-2024	11.11 - Preconstruction Activity
63	CONL1000	Demo South Bus (Nasonville D-Sub Exp.)	40d	Jan-7-2025	Mar-3-2025	
64	**Testing and Commissioning**		40d	Dec-3-2025	Jan-30-2026	
65	TEST/COM1000	Testing and Commssioning (Nasonville D-Sub Exp.)	40d	Dec-3-2025	Jan-30-2026	
66	A1310	Protection (PTO) Perform Relay Testing (Nasonville D-Sub Exp.)	40d	Dec-3-2025	Jan-30-2026	Duration TBC
67	**Close Out**		137d	Mar-2-2026	Sep-11-2026	
68	**Contract Close out**		47d	Jul-8-2026	Sep-11-2026	
69	CCO1000	Dev & Submit WO Summary (Nasonville D-Sub Exp.)	5d	Jul-8-2026	Jul-14-2026	
70	CCO1010	Work Orders Closed in PowerPlant (Nasonville D-Sub Exp.)	20d	Jul-15-2026	Aug-11-2026	
71	CCO1020	Project Closure Report (Nasonville D-Sub Exp.)	20d	Aug-12-2026	Sep-9-2026	
72	CCO1030	Project Schedule Closed (Nasonville D-Sub Exp.)	2d	Sep-10-2026	Sep-11-2026	
73	**Financial Closeout**		20d	Jul-15-2026	Aug-11-2026	
74	CCO1040	Funding Project Closed (Nasonville D-Sub Exp.)	20d	Jul-15-2026	Aug-11-2026	
75	**Civil As-Built**		75d	Mar-2-2026	Jun-15-2026	
76	ENGCIV3010	Construction Team to Develop As Built Mark-up/Redlines (Nasonville D-Sub Exp.)	20d	Mar-2-2026	Mar-27-2026	
77	ENGCIV3020	Review of As-Built Mark-up/Red lines (Nasonville D-Sub Exp.)	15d	Mar-30-2026	Apr-17-2026	
78	ENGCIV3030	Develop and issue final signed and sealed as-built documents and drawings (Nasonville D-Sub Exp.)	40d	Apr-20-2026	Jun-15-2026	
79	**Substation As-Built**		75d	Mar-23-2026	Jul-7-2026	
80	ENGLIN5050	Construction Team to Develop As Built Mark-up/Redlines (Nasonville D-Sub Exp.)	20d	Mar-23-2026	Apr-17-2026	
81	ENGLIN5060	Review of As-Built Mark-up/Red lines (Nasonville D-Sub Exp.)	15d	Apr-20-2026	May-8-2026	
82	ENGLIN5070	Develop and issue final signed and sealed as-built documents and drawings (Nasonville D-Sub Exp.)	40d	May-11-2026	Jul-7-2026	



Actual Work | Critical Remaining Work | Summary
Remaining Work | Milestone

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Division 1-56
Fiber

Request:

Provide a copy of the Company's detailed fiber deployment study conducted in FY 2025.

Response:

The fiber deployment study has not been completed yet. The Company anticipates this will be done in mid-December. The Company will provide the Division the study once it has been received and reviewed along with an update to the proposed spending for FY 2027 and beyond.

The Company included $500,000 in the FY 2026 ISR Plan for detailed design and permitting activities.

Prepared by or under the supervision of: Ryan Constable

Division 1-57
Fiber

Request:

On Bates page 90, the Company proposes $500,000 of spend in FY 2026 for a Fiber Network and no capital thereafter. Please expand on the Company's intended implementation plan, proposed over four to five years, and where the capital expenditures will occur within the ISR Plan.

Response:

The Company's proposed $500,000 of spend in FY 2026 for a Fiber Network is to complete the study and proceed to detailed engineering and begin permitting activities. The study, to be completed in FY 2025, is intended to refine the scope, schedule, and cost. However, the Company's previous estimate was approximately $48 million spread across three years.

Prepared by or under the supervision of: Ryan Constable

Division 1-58
Fiber

Request:

The Company states that the Fiber Network alternative is to do nothing and that "Without this program, station communications costs will rise greater than the cost of this program." Please provide support for this assessment.

Response:

The statement was made with the best available information at the time and with the expectation that the project estimate was likely to decrease pending the ongoing study.

As of the date of this response, the Company has received the draft fiber study and is currently reviewing and providing comments to the study consultant. At this time, the expected cost of bringing fiber to targeted substations is approximately $28.5 million, which could be adjusted based on the Company's review of the study. The Company estimates the cellular cost to be between $7 million and $12 million and the impact on engineering and control center operator time due to communication loss and data gaps to be between $14 million and $25 million over the next 20 to 30 years, bringing the expected rise in station communication costs to a range of $21 million to $37 million.

The Company recognizes that these estimates reflect the possibility that the "do nothing" option could be lower cost than pursuing the Fiber Network. In light of that recognition, once the fiber study is approved and a more accurate estimate is available, the Company will reevaluate its options and determine the most effective plan.

Prepared by or under the supervision of: Ryan Constable

Division 1-59
IIJA Funding

Request:

Does the first performance period start October 1, 2024 or October 1, 2025? Does the Company have flexibility in determining the commencement date?

Response:

The first performance period starts on October 1, 2024. The U.S. Department of Energy established the commencement date, and the Company does not have any unilateral flexibility in determining the commencement date.

Division 1-60

IIJA Funding

Request:

Has RIE pre-determined projects and received commitments for federal funding towards those investments? Explain and expand on the agreement terms and conditions that address eligible investments, funding commitments, timing, and specifically what is expected of the Company to make investments "in accordance with the award agreement." (Bates page 43)

Response:

Investments that are eligible for federal funding under the IIJA award from the U.S. Department of Energy ("DOE") have been pre-determined based on the Company's grant proposal and subsequent award agreement with the DOE.

Information on the project and commitments are described in the Grid Resilience and Innovation Partnership Program Announcement (https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects).

Please see Attachment DIV 1-60 for the Special Terms and Conditions that have been provided by the DOE. The Company has not yet formally accepted the award; therefore, the Company's acceptance of the terms and conditions remains pending.

Prepared by or under the supervision of: Nicole Gooding

SPECIAL TERMS AND CONDITIONS FOR USE IN MOST GRANTS AND COOPERATIVE AGREEMENTS

LEGAL AUTHORITY AND EFFECT (JUNE 2015)

(a) A DOE financial assistance award is valid only if it is in writing and is signed, either in writing or electronically, by a DOE Contracting Officer.

(b) Recipients are free to accept or reject the award. A request to draw down DOE funds constitutes the Recipient's acceptance of the terms and conditions of this Award.

RESOLUTION OF CONFLICTING CONDITIONS

Any apparent inconsistency between Federal statutes and regulations and the terms and conditions contained in this award must be referred to the DOE Award Administrator for guidance.

AWARD AGREEMENT TERMS AND CONDITIONS – BIPARTISAN INFRASTRUCTURE LAW (DECMBER 2014) (NETL – APRIL 2024)

This agreement consists of the Assistance Agreement Cover Page and Award Terms and Conditions of this Assistance Agreement, plus the following:

Attachment 0	Special Terms and Conditions
Attachment 1	Intellectual Property Provisions
Attachment 2	Statement of Project Objectives
Attachment 3	Federal Assistance Reporting Checklist and Instructions
Attachment 4	Budget Information
Attachment 5	Community Benefits Outcomes and Objectives

The following are incorporated into this Award by reference:

- DOE Assistance Regulations, 2 CFR part 200 as supplemented by 2 CFR part 910 at https://www.eCFR.gov.
- National Policy Requirements (November 12, 2020) at https://www.nsf.gov/awards/managing/rtc.jsp.
- As applicable, Public Law 117-58, also known as the Bipartisan Infrastructure Law (BIL).
- The Recipient’s application/proposal as approved by DOE.

CONFERENCE SPENDING (FEBRUARY 2015)

The recipient shall not expend any funds on a conference not directly and programmatically related to the purpose for which the grant or cooperative agreement was awarded that would defray the cost to the United States Government of a conference held by any Executive branch department, agency, board, commission, or office for which the cost to the United States Government would otherwise exceed $20,000, thereby circumventing the required notification by the head of any such Executive Branch department, agency, board, commission, or office to the Inspector General (or senior ethics official for any entity without an Inspector General), of the date, location, and number of employees attending such conference.

PAYMENT PROCEDURES - REIMBURSEMENT THROUGH THE AUTOMATED CLEARING HOUSE (ACH) VENDOR INQUIRY PAYMENT ELECTRONIC REPORTING SYSTEM (VIPERS)

a. Method of Payment. Payment will be made by reimbursement through ACH.

b. Requesting Reimbursement. Requests for reimbursements must be made electronically through Department of Energy's Oak Ridge Financial Service Center (ORFSC) VIPERS. To access and use VIPERS, you must enroll at https://vipers.doe.gov. Detailed instructions on how to enroll are provided on the web site.

For non-construction awards, you must submit a Standard Form (SF) 270, "Request for Advance or Reimbursement" at https://vipers.doe.gov and attach a file containing appropriate supporting documentation. The file attachment must show the total federal share claimed on the SF 270, the non-federal share claimed for the billing period if cost sharing is required, and cumulative expenditures to date (both Federal and non-Federal) for each of the following categories: salaries/wages and fringe benefits; equipment; travel; participant/training support costs, if any; other direct costs, including subawards/contracts; and indirect costs. For construction awards, you must submit a SF 271, "Outlay Report and Request for Reimbursement for Construction Programs," through VIPERS.

c. Timing of submittals. Submittal of the SF 270 or SF 271 should coincide with your normal billing pattern, but not more frequently than every two weeks. Requests for reimbursement must be limited to the amount of disbursements made during the billing period for the federal share of direct project costs and the proportionate share of any allowable indirect costs incurred during that billing period. **At a minimum, Recipient's should meet the required cost share percentage (specified in the Cost Sharing Term) by each go/no go decision point specified in the Project Management Plan.**

d. Adjusting payment requests for available cash. You must disburse any funds that are available from repayments to and interest earned on a revolving fund, program income, rebates, refunds, contract settlements, audit recoveries, credits, discounts, and interest earned on any of those funds before requesting additional cash payments from DOE/NNSA.

e. Payments. The DOE approving official will approve the invoice as soon as practicable but not later than 30 days after your request is received, unless the billing is improper. Upon receipt of an invoice payment authorization from the DOE approving official, the ORFSC will disburse payment to you. You may check the status of your payments at the VIPER web site. All payments are made by electronic funds transfer to the bank account identified on the ACH Vendor/Miscellaneous Payment Enrollment Form (SF 3881) that you filed.

COST SHARING

a. Total Estimated Project Cost is the sum of the Government share and Recipient share of the estimated project costs. The Recipient's cost share must come from non-Federal sources unless otherwise allowed by law. By accepting federal funds under this award, you agree that you are liable for your percentage share of total allowable project costs, on a budget period basis, even if the project is terminated early or is not funded to its completion. This cost is shared as follows:

Budget Period No.	Government Share		Recipient Share		Total
	$	%	$	%	
1	$50,000,000	18%	$233,302,326	82%	$283,302,326
Total Project	$50,000,000	18%	$233,302,326	82%	$283,302,326

b. If you discover that you may be unable to provide cost sharing of at least the amount identified in paragraph a of this term, you should immediately provide written notification to the DOE Award Administrator indicating whether you will continue or phase out the project. If you plan to continue the project, the notification must describe how replacement cost sharing will be secured.

c. You must maintain records of all project costs that you claim as cost sharing, including in-kind costs, as well as records of costs to be paid by DOE/NNSA. Such records are subject to audit.

d. Failure to provide the cost sharing required by this term may result in the subsequent recovery by DOE/NNSA of some or all the funds provided under the award.

REBUDGETING AND RECOVERY OF INDIRECT COSTS – REIMBURSABLE FRINGE BENEFITS AND NO INDIRECT COSTS

a. If actual allowable fringe benefits are less than those budgeted and funded under the award, you may use the difference to pay additional allowable direct costs during the project period. If at the completion of the award the Government's share of total allowable costs (i.e., direct and indirect), is less than the total costs reimbursed, you must refund the difference.

b. Recipients are expected to manage their fringe benefits. DOE will not amend an award solely to provide additional funds for changes in fringe benefit rates. DOE recognizes that the inability to obtain full reimbursement for fringe benefits means the recipient must absorb the underrecovery. Such underrecovery may be allocated as part of the organization's required cost sharing.

c. The budget for this award includes fringe benefits but does not include indirect costs. Therefore, indirect costs shall not be charged to, nor shall reimbursement be requested for this project nor shall the indirect costs for this project be allocated to any other federally sponsored project. In addition, indirect costs shall not be counted as cost share unless approved by the Contracting Officer.

USE OF PROGRAM INCOME - DEDUCTION

If you earn program income during the project period as a result of this award, you must deduct the program income from the total allowable project costs to determine the net allowable costs on which the Federal share is based.

STATEMENT OF FEDERAL STEWARDSHIP

DOE/NNSA will exercise normal Federal stewardship in overseeing the project activities performed under this award. Stewardship activities include, but are not limited to, conducting site visits; reviewing performance and financial reports; providing technical assistance and/or temporary intervention in unusual circumstances to correct deficiencies which develop during the project; assuring compliance with terms and conditions; and reviewing technical performance after project completion to ensure that the award objectives have been accomplished.

SITE VISITS

DOE/NNSA's authorized representatives have the right to make site visits at reasonable times to review project accomplishments and management control systems and to provide technical assistance, if required. You must provide, and must require your subrecipients to provide, reasonable access to facilities, office space, resources, and assistance for the safety and convenience of the government representatives in the performance of their duties. All site visits and evaluations must be performed in a manner that does not unduly interfere with or delay the work.

REPORTING REQUIREMENTS (APRIL 2023)

a. Requirements. The reporting requirements for this award are identified on the Federal Assistance Reporting Checklist, DOE F 4600.2, attached to this award. Failure to comply with these reporting requirements is considered a material noncompliance with the terms of the award. Noncompliance may result in withholding of future payments, suspension, or termination of the current award, and withholding of future awards. A willful failure to perform, a history of failure to perform, or unsatisfactory performance of this and/or other financial assistance awards, may also result in a debarment action to preclude future awards by Federal agencies.

b. Dissemination of scientific/technical reporting products. Reporting project results in scientific and technical information (STI) publications/products to the DOE Office of Scientific and Technical Information (OSTI) ensures dissemination of research results to the public as well as preservation of the results. The DOE form F 4600.2, B. Scientific/Technical Reporting, has instructions for the DOE Energy Link (E-Link) system managed by OSTI. Scientific/technical reports and other STI products submitted under this award will be disseminated publicly on the Web via OSTI.GOV (https://www.osti.gov), unless the STI contains patentable material, protected data, or SBIR/STTR data, which must be indicated per instructions in DOE 4600.2.

c. Restrictions. STI products submitted to the DOE via E-link must not contain any Protected Personally Identifiable Information (PII), limited rights data, classified information, information subject to export control classification, or other information not subject to public release. The Contracting Officer or Technical Project Officer should be contacted with any questions. Limited rights data means data (other than computer software) developed at private expense that embody trade secrets or are commercial or financial and confidential or privileged. SBIR/STTR Protected Data, and other data subject to statutory data protection authorized by the award may be submitted, provided such data is properly marked and identified during submission. Submissions must not contain any “Proprietary”, “Confidential” or “Business Sensitive” markings or similar restrictive markings not authorized by the applicable government agreement.; it is acknowledged that DOE has the right to cancel or ignore such markings.

PUBLICATIONS

a. You are encouraged to publish or otherwise make publicly available the results of the work conducted under the award.

b. An acknowledgment of Federal support and a disclaimer must appear in the publication of any material, whether copyrighted or not, based on or developed under this project, as follows:

Acknowledgment: "This material is based upon work supported by the Department of Energy, Grid Deployment Office, under Award Number DE-GD0000910."

Disclaimer: "This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

FEDERAL, STATE, AND MUNICIPAL REQUIREMENTS

You must obtain any required permits and comply with applicable federal, state, and municipal laws, codes, and regulations for work performed under this award.

INTELLECTUAL PROPERTY PROVISIONS AND CONTACT INFORMATION

a. The intellectual property provisions applicable to this award are provided as an attachment to this award or are referenced on the Assistance Agreement Face Page. A list of all intellectual property provisions may be found at http://energy.gov/gc/standard-intellectual-property-ip-provisions-financial-assistance-awards

b. Questions regarding intellectual property matters should be referred to the DOE Award Administrator and the Patent Counsel designated as the service provider for the DOE office that issued the award. The IP Service Providers List is found at http://energy.gov/gc/downloads/intellectual-property-ip-service-providers-acquisition-and-assistance-transactions

NOTICE REGARDING THE PURCHASE OF AMERICAN-MADE EQUIPMENT AND PRODUCTS -- SENSE OF CONGRESS

It is the sense of the Congress that, to the greatest extent practicable, all equipment and products purchased with funds made available under this award should be American-made.

INSURANCE COVERAGE (DECEMBER 2014)

See 2 CFR 200.310 for insurance requirements for real property and equipment acquired or improved with Federal funds.

REAL PROPERTY (DECEMBER 2014)

Subject to the conditions set forth in 2 CFR Part 200.311, title to real property acquired or improved under a Federal award will vest upon acquisition in the non-Federal entity.

The non-Federal entity cannot encumber this property and must follow the requirements of 2 CFR Part 200.311 before disposing of the property.

Except as otherwise provided by Federal statutes or by the Federal awarding agency, real property will be used for the originally authorized purpose as long as needed for that purpose. When real property is no longer needed for the originally authorized purpose, the non-Federal entity must obtain disposition instructions from the Federal awarding agency or pass-through entity. The instructions must provide for one of the following alternatives: (a) retain title after compensating the Federal awarding agency as described in 2 CFR Part 200.311(c)(1); (b) Sell the property and compensate the federal awarding agency as specified in CFR Part 200.311(c)(2); or (c) transfer title to the Federal awarding agency or to a third Party designated/approved by the Federal awarding agency as specified in CFR Part 200.311(c)(3).

See 2 CFR Part 200.311 for additional requirements pertaining to real property acquired or improved under a Federal award.

Also see 2 CFR Part 910.360 for amended requirements for Real Property for For-Profit recipients.

EQUIPMENT (DECEMBER 2014) (NETL – MAY 2024)

Subject to the conditions provided in 2 CFR 200.313 and 2 CFR 910.360 (as applicable), title to equipment (property) acquired under a Federal award will vest conditionally with the non-Federal entity.

The non-Federal entity cannot encumber this property or permit encumbrance without prior written approval by the DOE Contracting Officer and must follow the requirements of 2 CFR 200.313 before disposing of the property.

States must use equipment acquired under a Federal award by the state in accordance with state laws and procedures.

Equipment must be used by the non-Federal entity in the program or project for which it was acquired as long as it is needed, whether or not the project or program continues to be supported by the Federal award. When no longer needed for the originally authorized purpose, the equipment may be used by programs supported by the Federal awarding agency in the priority order specified in 2 CFR 200.313(c)(1)(i) and (ii).

Management requirements, including inventory and control systems, for equipment are provided in 2 CFR 200.313(d).

When equipment acquired under a Federal award is no longer needed, the non-Federal entity must obtain disposition instructions from the Federal awarding agency or pass-through entity. However, pursuant to the FY23 Consolidated Appropriations Act (Pub. L. No. 117-328), Division D, Title III, Section 309, the Secretary, or a designee of the Secretary may, at their discretion, vest unconditional title or other property interests acquired under this project regardless of the fair market value of the property at the end of the award period.

Subject to the vesting of any property pursuant to Section 309 of the FY23 Consolidated Appropriations Act (Pub. L. No. 117-328), Division D, Title III, disposition will be made as follows: (a) items of equipment with a current fair market value of $5,000 or less may be retained, sold, or otherwise disposed of with no further obligation to the Federal awarding agency; (b) non-Federal entity may retain title or sell the equipment after compensating the Federal awarding agency as described in 2 CFR 200.313(e)(2); or (c) transfer title to the Federal awarding agency or to an eligible third Party as specified in 2 CFR 200.313(e)(3).

See 2 CFR 200.313 for additional requirements pertaining to equipment acquired under a Federal award. Also see 2 CFR 200.439 Equipment and other capital expenditures.

See 2 CFR 910.360 for supplemental requirements for Equipment for for-profit Recipients.

SFY23 SECTION 309 AUTHORITY – UNCONDITIONAL TITLE VESTING

Pursuant to the FY23 Consolidated Appropriations Act (Pub. L. No. 117-328), Division D, Title III, Section 309 (“Section 309 authority”), the Secretary of Energy, or the Secretary’s designee may, at their discretion, vest unconditional title or other property interests acquired under this project in the award recipient, subrecipient, or successor in interest, regardless of the fair market value of the property, at the conclusion of the award period. Under this award, if requested by the Recipient, DOE will not unreasonably withhold exercising Section 309 authority to vest unconditional title or other property interests acquired under this project in equipment and real property in the Recipient at the conclusion of the award period, provided that the Recipient satisfies the following conditions. Recipient agrees to:

1. comply with award terms and conditions, including all applicable DOE program requirements, including any
   amendments.
2. use the equipment or real property during the award period for its originally authorized project purpose.
3. complete all tasks, objectives, and milestones included in Attachment 2, Statement of Project Objectives.
4. certify that it will not sell or transfer the equipment or real property to a Foreign Country of Risk or State
   Sponsor of Terrorism, or to an entity owned, controlled by, incorporated in, or located in those countries, after
   the conclusion of the award period; and
5. ensure installed grid assets were installed appropriately, contributing to safe and reliable delivery of electric
   service as appropriate and are maintained appropriately to ensure their anticipated service lives.

Recipient is required to advise DOE on its progress on the above conditions at various points throughout the life of the award, including but not limited to, continuations, go/no-go decision points, and budget periods. DOE will require a final presentation and/or written narrative by Recipient immediately prior to the conclusion of the award period for the recipient to demonstrate to DOE's satisfaction that it has satisfied the above conditions, prior to DOE effecting any final transfer of title under Section 309. After any disposition of DOE's reversionary interest, a continuing agreement between Recipient and DOE may nonetheless remain in place to fulfill other award requirements or to properly effectuate the exercise of Section 309 authority (if not otherwise incorporated into the award), regardless of the success of the project or ongoing performance under this award.

SUPPLIES (DECEMBER 2014)

See 2 CFR Part 200.314 for requirements pertaining to supplies acquired under a Federal award.

See also § 200.453 Materials and supplies costs, including costs of computing devices.

INTANGIBLE PROPERTY (DECEMBER 2014)

Title to intangible property (as defined in 2 CFR Part 200.59) acquired under a Federal award vests upon acquisition in the non-Federal entity. Intangible property includes trademarks, copyrights, patents and patent applications.

See 2 CFR Part 200.315 for additional requirements pertaining to intangible property acquired under a Federal award.

Also see 2 CFR Part 910.362 for amended requirements for Intellectual Property for For-Profit recipients.

PROPERTY TRUST RELATIONSHIP (DECEMBER 2014)

Real property, equipment, and intangible property, that are acquired or improved with a Federal award must be held in trust by the non-Federal entity as trustee for the beneficiaries of the project or program under which the property was acquired or improved.

See 2 CFR Part 200.316 for additional requirements pertaining to real property, equipment, and intangible property acquired or improved under a Federal award.

INSOLVENCY, BANKRUPTCY OR RECEIVERSHIP

a. You shall immediately notify the DOE of the occurrence of any of the following events: (i) you or your parent's filing of a voluntary case seeking liquidation or reorganization under the Bankruptcy Act; (ii) your consent to the institution of an involuntary case under the Bankruptcy Act against you or your parent; (iii) the filing of any similar proceeding for or against you or your parent, or its consent to, the dissolution, winding-up or readjustment of your debts, appointment of a receiver, conservator, trustee, or other officer with similar powers over you, under any other applicable state or federal law; or (iv) your insolvency due to your inability to pay your debts generally as they become due.

b. Such notification shall be in writing and shall: (i) specifically set out the details of the occurrence of an event referenced in paragraph a; (ii) provide the facts surrounding that event; and (iii) provide the impact such event will have on the project being funded by this award.

c. Upon the occurrence of any of the four events described in the first paragraph, DOE reserves the right to conduct a review of your award to determine your compliance with the required elements of the award (including such items as cost share, progress towards technical project objectives, and submission of required reports). If the DOE review determines that there are significant deficiencies or concerns with your performance under the award, DOE reserves the right to impose additional requirements, as needed, including (i) change your payment method; or (ii) institute payment controls.

d. Failure of the Recipient to comply with this term may be considered a material noncompliance of this financial assistance award by the Contracting Officer.

PERFORMANCE OF WORK IN UNITED STATES

The Recipient agrees that all work under this award shall be performed in the United States, unless the Recipient can demonstrate to the satisfaction of the Department of Energy that the United States economic interest will be better served through a greater percentage of the work being performed outside the United States.

CATEGORICAL EXCLUSION (CX)

DOE must comply with the National Environmental Policy Act (NEPA) prior to authorizing the use of federal funds. Based on all information provided by the Recipient, DOE has made a NEPA determination by issuing a CX, thereby authorizing use of funds for the defined project activities. If the Recipient later adds to or modifies the activities reviewed and approved under the original DOE NEPA determination, the Recipient must notify the DOE Contracting Officer before proceeding with the new and/or modified activities. Those additions or modifications may be subject to review by the DOE NEPA Compliance Officer and approval by the DOE Contracting Officer and may require a new NEPA determination.

SYSTEM FOR AWARD MANAGEMENT AND UNIVERSAL IDENTIFIER REQUIREMENTS

A. Requirement for System for Award Management (SAM) Unless exempted from this requirement under 2 CFR 25.110, the prime recipient must remain registered and maintain current information in SAM for the entire period of performance of the award. This includes providing information on the prime recipient's immediate and highest level owner and subsidiaries, as well as on all of its predecessors that have been awarded a Federal contract or Federal financial assistance agreements within the last three years, if applicable, until the prime recipient submits the final financial report required under this award or receives the final payment, whichever is later. This requires the prime recipient to review its information in SAM at least annually after the initial registration, and to update its information as soon as there are changes. Reviews and updates may be required more frequently due to changes in recipient information or as required by another award term.

B. Requirement for Unique Entity Identifier

If authorized to make subawards under this award, the prime recipient:

1. Must notify potential subrecipients that no entity (see definition in paragraph C of this award term) may receive a subaward until the entity has provided its unique entity identifier to the prime recipient.

2. Must not make a subaward to an entity unless the entity has provided its unique entity identifier to the prime recipient. Subrecipients are not required to obtain an active SAM registration, but must obtain a unique entity identifier.

C. Definitions

For purposes of this term:

1. System for Award Management (SAM) means the Federal repository into which a recipient must provide information required for the conduct of business as a recipient. Additional information about registration procedures may be found at the SAM internet site (currently at https://www.sam.gov).

2. Unique Entity Identifier means the identifier assigned by SAM to uniquely identify business entities.

3. Entity includes non-Federal entities as defined at 2 CFR 200.1 and also includes all of the following for purposes of this part:

a. A foreign organization;

b. A foreign public entity;

c. A domestic for-profit organization; and

d. A Federal agency.

4. Subaward has the meaning given in 2 CFR 200.1.

5. Subrecipient has the meaning given in 2 CFR 200.1.

FINAL INCURRED COST AUDIT (DECEMBER 2014)

In accordance with 2 CFR Part 200 as amended by 2 CFR Part 910, DOE reserves the right to initiate a final incurred cost audit on this award. If the audit has not been performed or completed prior to the closeout of the award, DOE retains the right to recover an appropriate amount after fully considering the recommendations on disallowed costs resulting from the final audit.

LOBBYING RESTRICTIONS (MARCH 2012)

By accepting funds under this award, you agree that none of the funds obligated on the award shall be expended, directly or indirectly, to influence congressional action on any legislation or appropriation matters pending before Congress, other than to communicate to Members of Congress as described in 18 U.S.C. 1913. This restriction is in addition to those prescribed elsewhere in statute and regulation.

CORPORATE FELONY CONVICTION AND FEDERAL TAX LIABILITY ASSURANCES (MARCH 2014)

By entering into this agreement, the undersigned attests that The Narragansett Electric Company has not been convicted of a felony criminal violation under Federal law in the 24 months preceding the date of signature.

The undersigned further attests that The Narragansett Electric Company does not have any unpaid Federal tax liability that has been assessed, for which all judicial and administrative remedies have been exhausted or have lapsed, and that is not being paid in a timely manner pursuant to an agreement with the authority responsible for collecting the tax liability.

For purposes of these assurances, the following definitions apply:

A Corporation includes any entity that has filed articles of incorporation in any of the 50 states, the District of Columbia, or the various territories of the United States [but not foreign corporations]. It includes both for-profit and non-profit organizations.

NONDISCLOSURE AND CONFIDENTIALITY AGREEMENTS ASSURANCES (JUNE 2015)

(1) By entering into this agreement, the undersigned attests that The Narragansett Electric Company does not and will not require its employees or contractors to sign internal nondisclosure or confidentiality agreements or statements prohibiting or otherwise restricting its employees or contactors from lawfully reporting waste, fraud, or abuse to a designated investigative or law enforcement representative of a Federal department or agency authorized to receive such information.

(2) The undersigned further attests that The Narragansett Electric Company does not and will not use any Federal funds to implement or enforce any nondisclosure and/or confidentiality policy, form, or agreement it uses unless it contains the following provisions:

a.‘‘These provisions are consistent with and do not supersede, conflict with, or otherwise alter the employee obligations, rights, or liabilities created by existing statute or Executive order relating to (1) classified information, (2) communications to Congress, (3) the reporting to an Inspector General of a violation of any law, rule, or regulation, or mismanagement, a gross waste of funds, an abuse of authority, or a substantial and specific danger to public health or safety, or (4) any other whistleblower protection. The definitions, requirements, obligations, rights, sanctions, and liabilities created by controlling Executive orders and statutory provisions are incorporated into this agreement and are controlling.’’

b. The limitation above shall not contravene requirements applicable to Standard Form 312, Form 4414, or any other form issued by a Federal department or agency governing the nondisclosure of classified information.

c. Notwithstanding provision listed in paragraph (a), a nondisclosure or confidentiality policy form or agreement that is to be executed by a person connected with the conduct of an intelligence or intelligence-related activity, other than an employee or officer of the United States Government, may contain provisions appropriate to the particular activity for which such document is to be used. Such form or agreement shall, at a minimum, require that the person will not disclose any classified information received in the course of such activity unless specifically authorized to do so by the United States Government. Such nondisclosure or confidentiality forms shall also make it clear that they do not bar disclosures to Congress, or to an authorized official of an executive agency or the Department of Justice, that are essential to reporting a substantial violation of law.

REPORTING OF MATTERS RELATED TO RECIPIENT INTEGRITY AND PERFORMANCE (DECEMBER 2015)

a. General Reporting Requirement

If the total value of your currently active grants, cooperative agreements, and procurement contracts from all Federal awarding agencies exceeds $10,000,000 for any period of time during the period of performance of this Federal award, then you as the recipient during that period of time must maintain the currency of information reported to the System for Award Management (SAM) that is made available in the designated integrity and performance system (currently the Federal Awardee Performance and Integrity Information System (FAPIIS)) about civil, criminal, or administrative proceedings described in paragraph 2 of this award term and condition. This is a statutory requirement under section 872 of Public Law 110-417, as amended (41 U.S.C. 2313). As required by section 3010 of Public Law 111-212, all information posted in the designated integrity and performance system on or after April 15, 2011, except past performance reviews required for Federal procurement contracts, will be publicly available.

b. Proceedings About Which You Must Report

Submit the information required about each proceeding that:

1. Is in connection with the award or performance of a grant, cooperative agreement, or procurement contract from the Federal Government;

2. Reached its final disposition during the most recent five year period; and

3. Is one of the following:

(A) A criminal proceeding that resulted in a conviction, as defined in paragraph 5 of this award term and condition;

(B) A civil proceeding that resulted in a finding of fault and liability and payment of a monetary fine, penalty, reimbursement, restitution, or damages of $5,000 or more;

(C) An administrative proceeding, as defined in paragraph 5. of this award term and condition, that resulted in a finding of fault and liability and your payment of either a monetary fine or penalty of $5,000 or more or reimbursement, restitution, or damages in excess of $100,000; or

(D) Any other criminal, civil, or administrative proceeding if:

(i) It could have led to an outcome described in paragraph 2.c.(1), (2), or (3) of this award term and condition;

(ii) It had a different disposition arrived at by consent or compromise with an acknowledgment of fault on your part; and

(iii) The requirement in this award term and condition to disclose information about the proceeding does not conflict with applicable laws and regulations.

c. Reporting Procedures

Enter in the SAM Entity Management area the information that SAM requires about each proceeding described in paragraph 2 of this award term and condition. You do not need to submit the information a second time under assistance awards that you received if you already provided the information through SAM because you were required to do so under Federal procurement contracts that you were awarded.

d. Reporting Frequency

During any period of time when you are subject to the requirement in paragraph 1 of this award term and condition, you must report proceedings information through SAM for the most recent five year period, either to report new information about any proceeding(s) that you have not reported previously or affirm that there is no new information to report. Recipients that have Federal contract, grant, and cooperative agreement awards with a cumulative total value greater than $10,000,000 must disclose semiannually any information about the criminal, civil, and administrative proceedings.

e. Definitions

For purposes of this award term and condition:

1. Administrative proceeding means a non-judicial process that is adjudicatory in nature in order to make a determination of fault or liability (e.g., Securities and Exchange Commission Administrative proceedings, Civilian Board of Contract Appeals proceedings, and Armed Services Board of Contract Appeals proceedings). This includes proceedings at the Federal and State level but only in connection with performance of a Federal contract or grant. It does not include audits, site visits, corrective plans, or A. Reporting of Matters Related to Recipient Integrity and Performance.

2. Conviction, for purposes of this award term and condition, means a judgment or conviction of a criminal offense by any court of competent jurisdiction, whether entered upon a verdict or a plea, and includes a conviction entered upon a plea of nolo contendere.

3. Total value of currently active grants, cooperative agreements, and procurement contracts includes—

(A) Only the Federal share of the funding under any Federal award with a recipient cost share or match; and

(B) The value of all expected funding increments under a Federal award and options, even if not yet exercised.

SUBAWARD/SUBCONTRACT CHANGE NOTIFICATION

Except for subawards and/or subcontracts specifically proposed as part of the Recipient's Application for award, the Recipient must notify the DOE Contracting Officer and Project Officer in writing 30 days prior to the execution of new or modified subawards/subcontracts. This notification does not constitute a waiver of the prior approval requirements outlined in 2 CFR 200, nor does it relieve the Recipient from its obligation to comply with applicable Federal statutes, regulations, and executive orders.

In order to satisfy this notification requirement, Recipient documentation must, as a minimum, include the following:

1. A description of the research to be performed, the service to be provided, or the equipment to be purchased;
2. Cost share commitment letter if the subawardee is providing cost share to the award;
3. Updated budget justification, budget pages;
4. An assurance that the process undertaken by the Recipient to solicit the subaward/subcontract complies with their written procurement procedures as outlined in 2 CFR 200.317 through 200.327.
5. An assurance that no planned, actual or apparent conflict of interest exists between the Recipient and the selected subawardee/subcontractor and that the Recipient's written standards of conduct were followed;[1]
6. A completed Environmental Questionnaire, if applicable;
7. An assurance that the subawardee/subcontractor is not a debarred or suspended entity; and
8. An assurance that all required award provisions will be flowed down in the resulting subaward/subcontract.

The Recipient is responsible for making a final determination to award or modify subawards/subcontracts under this agreement, but the Recipient may not proceed with the subaward/subcontract until the Contracting Officer determines, and provides the Recipient written notification, that the information provided is adequate.

Should the Recipient not receive a written notification of adequacy from the Contracting Officer within 30 days of the submission of the subaward/subcontract documentation stipulated above, Recipient may proceed to award or modify the proposed subaward/subcontract.

GO/NO-GO DECISION - NETL

The Government has elected to include go/no-go decision(s) in the Project Management Plan (PMP). If it is advantageous for the Government to proceed beyond the go/no go decision point(s), the Contracting Officer will notify the recipient in writing authorizing the recipient to proceed beyond the go/no go decision point in the PMP.

If it is determined that it would not be advantageous for the Government to proceed beyond the technical milestone(s), the Contracting Officer will notify the recipient in writing of such decision and the award is considered completed. The maximum liability to the Government is limited to the allowable, allocable, and reasonableness of the cost incurred by the recipient within the funds made available. The Government reserves the right to deobligate any remaining funds from the award. The recipient shall submit all final deliverables, including final project accomplishments, for the completed work in accordance with the reporting requirements of the award.

[1] It is DOE's position that the existence of a "covered relationship" as defined in 5 C.F.R. § 2635.502(a)&(b) between a member of the Recipient's owners or senior management and a member of a subawardee's/subcontractor's owners or senior management creates at a minimum an apparent conflict of interest that would require the Recipient to notify the Contracting Officer and provide detailed information and justification (including, for example, mitigation measures) as to why the subaward or subcontract does not create an actual conflict of interest. Recipients must also notify the Contracting Officer of any new subcontract or subaward to: (1) an entity that is owned or otherwise controlled by the Recipient; or (2) an entity that is owned or otherwise controlled by another entity that also owns or otherwise controls the Recipient, as it is DOE's position that these situations also create at a minimum an apparent conflict of interest.

IMPLEMENTATION OF EXECUTIVE ORDER 13798, PROMOTING FREE SPEECH AND RELIGIOUS LIBERTY (NOVEMBER 2020)

States, local governments, or other public entities may not condition sub-awards in a manner that would discriminate, or disadvantage sub-recipients based on their religious character.

CONTINUED USE OF REAL PROPERTY AND EQUIPMENT (OCTOBER 2022)

Real property and equipment purchased with project funds (federal share and recipient cost share) under this Award are subject to the requirements at 2 CFR 200.311, 200.313, and 200.316 (non-Federal entities, except for-profit entities) and 2 CFR 910.360 (for-profit entities). The Recipient may continue to use the real property and equipment after the conclusion of the award period of performance so long as the Recipient:

a. Continues to use the property for the authorized project purposes;
b. Complies with the applicable reporting requirements and regulatory property standards;
c. As applicable to for-profit entities, UCC filing statements are maintained; and
d. Submits a written Request for Continued Use for DOE authorization, which is approved by the DOE Contracting Officer.

The Recipient must request authorization from the Contracting Officer to continue to use the property for the authorized project purposes beyond the award period of performance ("Request for Continued Use"). The Recipient's written Request for Continued Use must identify the property and include: a summary of how the property will be used (must align with the authorized project purposes); a proposed use period (e.g., perpetuity, until fully depreciated, or a calendar date where the Recipient expects to submit disposition instructions); acknowledgement that the recipient shall not sell or encumber the property or permit any encumbrance without prior written DOE approval; current fair market value of the property; and an Estimated Useful Life or depreciation schedule for equipment.

When the property is no longer needed for authorized project purposes, the Recipient must request disposition instructions from DOE. For-profit entity disposition requirements are set forth at 2 CFR 910.360. Property disposition requirements for other non-federal entities are set forth in 2 CFR 200.310 through 200.316.

FOREIGN NATIONAL PARTICIPATION – APPROVAL REQUIRED (APRIL 2024)

If the Recipient (including any of its subrecipients and contractors) anticipates involving foreign nationals in the performance of this award, the Recipient must provide DOE with specific information about each foreign national to ensure compliance with the requirements for foreign national participation and access approvals. The volume and type of information required may depend on various factors associated with the award.

Approval for foreign nationals in Principal Investigator/Co-Principal Investigator roles, from countries of risk (i.e., China, Iran, North Korea, and Russia), and from countries identified on the U.S. Department of State's list of State Sponsors of Terrorism (https://www.state.gov/state-sponsors-of-terrorism/) must be obtained from DOE before they can participate in the performance of any work under this award.

A "foreign national" is defined as a person without United States citizenship or nationality (may include a stateless person). DOE may elect to deny a foreign national's participation in the award. Likewise, DOE may elect to deny a foreign national's access to a DOE sites, information, technologies, equipment, programs, or personnel. DOE's determination to deny participation or access is not appealable.

The Recipient must include this term in any subaward and in any applicable contractual agreement(s) associated with this award.

POST AWARD DUE DILIGENCE REVIEWS (APRIL 2024)

During the period of performance of the Award, DOE may conduct ongoing due diligence reviews, through Government resources, to identify potential risks of undue foreign influence. In the event a risk is identified, DOE may require risk mitigation measures, including but not limited to, requiring an individual or entity not participate in the Award. As part of the research, technology, and economic security risk review, DOE may contact the Recipient project team members for additional information to inform the review.

EXPORT CONTROL (JUNE 2024)

The United States government regulates the transfer of information, commodities, technology, and software considered to be strategically important to the U.S. to protect national security, foreign policy, and economic interests without imposing undue regulatory burdens on legitimate international trade. There is a network of Federal agencies and regulations that govern exports that are collectively referred to as "Export Controls." The Recipient is responsible for ensuring compliance with all applicable United States Export Control laws and regulations relating to any work performed under the award.

The Recipient must immediately report to DOE any export control investigations, charges, convictions, and violations upon occurrence, at the recipient or subrecipient level, and for convictions/violations, provide the corrective action(s) to prevent future convictions/violations.

INTERIM CONFLICT OF INTEREST POLICY FOR FINANCIAL ASSISTANCE (MARCH 2023)

The DOE interim Conflict of Interest Policy for Financial Assistance (COI Policy) can be found at https://www.energy.gov/management/department-energy-interim-conflict-interest-policy-requirements-financial-assistance. This policy is applicable to all non-Federal entities applying for, or that receive, DOE funding by means of a financial assistance award (e.g., a grant, cooperative agreement, or technology investment agreement) and, through the implementation of this policy by the entity, to each Investigator who is planning to participate in, or is participating in, the project funded wholly or in part under this Award. The term "Investigator" means the PI and any other person, regardless of title or position, who is responsible for the purpose, design, conduct, or reporting of a project funded by DOE or proposed for funding by DOE. The Recipient must flow down the requirements of the interim COI Policy to any subrecipient non-Federal entities, with the exception of DOE National Laboratories. Further, the Recipient must identify all financial conflicts of interests (FCOI), i.e., managed and unmanaged/ unmanageable, in its initial and ongoing FCOI reports.

Prior to award, the Recipient was required to: 1) ensure all Investigators on this Award completed their significant financial disclosures; 2) review the disclosures; 3) determine whether a FCOI exists; 4) develop and implement a management plan for FCOIs; and 5) provide DOE with an initial FCOI report that includes all FCOIs (i.e., managed and unmanaged/unmanageable). Within 180 days of the date of the Award, the Recipient must be in full compliance with the other requirements set forth in DOE's interim COI Policy.

ORGANIZATIONAL CONFLICT OF INTEREST (APRIL 2024)

Organizational conflicts of interest are those where, because of relationships with a parent company, affiliate, or subsidiary organization, the Recipient is unable or appears to be unable to be impartial in conducting procurement action involving a related organization (2 CFR 200.318(c)(2)).

The Recipient must disclose in writing any potential or actual organizational conflict of interest to the DOE Contracting Officer. The Recipient must provide the disclosure prior to engaging in a procurement or transaction using project funds with a parent, affiliate, or subsidiary organization that is not a state, local government, or Indian Tribe. For a list of the information that must be included the disclosure, see Section VI. of the DOE interim Conflict of Interest Policy for Financial Assistance at https://www.energy.gov/management/department-energy-interim-conflict-interest-policy-requirements-financial-assistance.

If the effects of the potential or actual organizational conflict of interest cannot be avoided, neutralized, or mitigated, the Recipient must procure goods and services from other sources when using project funds.

The Recipient must flow down the requirements of the interim COI Policy to any subrecipient non-Federal entities, with the exception of DOE National Laboratories. The Recipient is responsible for ensuring subrecipient compliance with this term.

If the Recipient has a parent, affiliate, or subsidiary organization that is not a state, local government, or Indian Tribe, the Recipient must maintain written standards of conduct covering organizational conflicts of interest.

PROHIBITION ON CERTAIN TELECOMMUNICATIONS AND VIDEO SURVEILLANCE SERVICES OR EQUIPMENT (APRIL 2024)

As set forth in 2 CFR 200.216, recipients and subrecipients are prohibited from obligating or expending project funds (Federal and non-Federal funds) to:

(1) Procure or obtain;

(2) Extend or renew a contract to procure or obtain;

(3) Exercise an option to procure; or

(4) Enter into a contract (or extend or renew a contract) to procure or obtain equipment, services, or systems that uses covered telecommunications equipment or services as a substantial or essential component of any system, or as critical technology as part of any system. As described in Public Law 115-

232, section 889, covered telecommunications equipment is telecommunications equipment produced by Huawei Technologies Company or ZTE Corporation (or any subsidiary or affiliate of such entities).

(i) For the purpose of public safety, security of government facilities, physical security surveillance of critical infrastructure, and other national security purposes, video surveillance and telecommunications equipment produced by Hytera Communications Corporation, Hangzhou Hikvision Digital Technology Company, or Dahua Technology Company (or any subsidiary or affiliate of such entities).

(ii) Telecommunications or video surveillance services provided by such entities or using such equipment.

(iii) Telecommunications or video surveillance equipment or services produced or provided by an entity that the Secretary of Defense, in consultation with the Director of the National Intelligence or the Director of the Federal Bureau of Investigation, reasonably believes to be an entity owned or controlled by, or otherwise connected to, the government of a covered foreign country.

See Public Law 115-232, section 889 for additional information.

PROHIBITION RELATED TO FOREIGN GOVERNMENT-SPONSORED TALENT RECRUITMENT PROGRAMS (MARCH 2023)

A. Prohibition

Persons participating in a *Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk* are prohibited from participating in this Award. The Recipient must exercise ongoing due diligence to reasonably ensure that no individuals participating on the DOE-funded project are participating in a *Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk*. Consequences for violations of this prohibition will be determined according to applicable law, regulations, and policy. Further, the Recipient must notify DOE within five (5) business days upon learning that an owner of the Recipient or subrecipient or individual on the project team is or is believed to be participating in a *Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk*. DOE may modify and add requirements related to this prohibition to the extent required by law.

B. Definitions

1. **Foreign Government-Sponsored Talent Recruitment Program**. An effort directly or indirectly organized, managed, or funded by a foreign government, or a foreign government instrumentality or entity, to recruit science and technology professionals or students (regardless of citizenship or national origin, or whether having a full-time or part-time position). Some foreign government-sponsored talent recruitment programs operate with the intent to import or otherwise acquire from abroad, sometimes through illicit means, proprietary technology or software, unpublished data and methods, and intellectual property to further the military modernization goals and/or economic goals of a foreign government. Many, but not all, programs aim to incentivize the targeted individual to relocate physically to the foreign state for the above purpose. Some programs allow for or encourage continued employment at United

States research facilities or receipt of federal research funds while concurrently working at and/or receiving compensation from a foreign institution, and some direct participants not to disclose their participation to U.S. entities. Compensation could take many forms including cash, research funding, complimentary foreign travel, honorific titles, career advancement opportunities, promised future compensation, or other types of remuneration or consideration, including in-kind compensation.

2. **Foreign Country of Risk**. DOE has designated the following countries as foreign countries of risk: Iran, North Korea, Russia, and China. This list is subject to change.

PARTICIPANTS AND OTHER COLLABORATING ORGANIZATIONS (APRIL 2024)

Prior to award, the Recipient was required to provide the following information on participants and other collaborating organizations. If there are any changes to Participants and Collaborating Organizations information previously submitted to DOE, the Recipient must submit updated information within thirty (30) calendar days after the end of the quarterly reporting period in which the change occurred:

A. What individuals have worked on the project

Provide the following information for individuals at the prime recipient and subrecipient level: (1) all senior and key personnel; (2) authorized representative of applicant with primary responsibility for business support (e.g., financial management, fiscal oversight, providing resources, award administration, etc.), if other than listed senior/key personnel, e.g., the Administrative Officer listed on the SF-424 Application; and (3) each person who has worked or is expected to work at least one person month per year on the project regardless of the source of compensation (a person month equals approximately 160 hours of effort).

i. Name
ii. Organization
iii. Job Title
iv. Role in the project
v. Start and end date (month and year) working on the project
vi. State, U.S. territory, and/or country of residence
vii. Whether this person collaborated with an individual or entity located in a foreign country in connection with the scope of this Award, and
viii. If yes to vii, whether the person traveled to the foreign country as part of that collaboration, and, if so, where and what the duration of stay was.

B. Organizations

Identify all subrecipients, contractors, U.S. National Laboratories, partners, and collaborating organizations. Recipients must also include all foreign collaborators as outlined in the Foreign Collaboration Considerations term of the award Terms and Conditions. For each, provide name, UEI, zip code or latitude/longitude, role in the project, contribution to the project and start and end date.

HUMAN SUBJECTS RESEARCH (MARCH 2023)

Research involving human subjects, biospecimens, or identifiable private information conducted with Department of Energy (DOE) funding is subject to the requirements of DOE Order 443.1C, *Protection of Human Research Subjects*, 45 CFR Part 46, *Protection of Human Subjects* (*subpart A which is referred to as the "Common Rule"),* and 10 CFR Part 745, *Protection of Human Subjects*.

Federal regulation and the DOE Order require review by an Institutional Review Board (IRB) of all proposed human subjects research projects. The IRB is an interdisciplinary ethics board responsible for ensuring that the proposed research is sound and justifies the use of human subjects or their data; the potential risks to human subjects have been minimized; participation is voluntary; and clear and accurate information about the study, the benefits and risks of participating, and how individuals' data/specimens will be protected/used, is provided to potential participants for their use in determining whether or not to participate.

The Recipient shall provide the Federal Wide Assurance number identified in item 1 below and the certification identified in item 2 below to DOE prior to initiation of any project that will involve interactions with humans in some way (e.g., through surveys); analysis of their identifiable data (e.g., demographic data and energy use over time); asking individuals to test devices, products, or materials developed through research; and/or testing of commercially available devices in buildings/homes in which humans will be present. *Note:* This list of examples is illustrative and not all inclusive.

No DOE funded research activity involving human subjects, biospecimens, or identifiable private information shall be conducted without:

1) A registration and a Federal Wide Assurance of compliance accepted by the Office of Human Research Protection (OHRP) in the Department of Health and Human Services; and
2) Certification that the research has been reviewed and approved by an Institutional Review Board (IRB) provided for in the assurance. IRB review may be accomplished by the awardee's institutional IRB; by the Central DOE IRB; or if collaborating with one of the DOE national laboratories, by the DOE national laboratory IRB.

The Recipient is responsible for ensuring all subrecipients comply and for reporting information on the project annually to the DOE Human Subjects Research Database (HSRD) at https://science.osti.gov/HumanSubjects/Human-Subjects-Database/home. *Note:* If a DOE IRB is used, no end of year reporting will be needed.

Additional information on the DOE Human Subjects Research Program can be found at: https://science.osti.gov/ber/human-subjects.

FRAUD, WASTE AND ABUSE (MARCH 2023)

The mission of the DOE Office of Inspector General (OIG) is to strengthen the integrity, economy and efficiency of DOE's programs and operations including deterring and detecting fraud, waste, abuse and mismanagement. The OIG accomplishes this mission primarily through investigations, audits, and inspections of Department of Energy activities to include grants, cooperative agreements, loans, and contracts. The OIG maintains a Hotline for reporting allegations of fraud, waste, abuse, or mismanagement. To report such allegations, please visit https://www.energy.gov/ig/ig-hotline.

Additionally, the Recipient must be cognizant of the requirements of 2 CFR 200.113 Mandatory disclosures, which states:

> The non-Federal entity or applicant for a Federal award must disclose, in a timely manner, in writing to the Federal awarding agency or pass-through entity all violations of Federal criminal law involving fraud, bribery, or gratuity violations potentially affecting the Federal award. Non-Federal entities that have received a Federal award including the term and condition outlined in appendix XII of 2 CFR Part 200 are required to report certain civil, criminal, or administrative proceedings to SAM (currently FAPIIS). Failure to make required disclosures can result in any of the remedies described in § 200.339. (See also 2 CFR part 180, 31 U.S.C. 3321, and 41 U.S.C. 2313.)

TRANSPARENCY OF FOREIGN CONNECTIONS (APRIL 2024)

The Recipient must notify the DOE Contracting Officer within fifteen (15) business days of learning of the following circumstances in relation to the Recipient and subrecipients:

1. Any current or pending subsidiary, foreign business entity, or offshore entity that is based in or funded by any foreign country of risk or foreign entity based in a country of risk;
2. Any current or pending contractual or financial obligation or other agreement specific to a business arrangement, or joint venture-like arrangement with an entity owned by a country of risk or foreign entity based in a country of risk;
3. Any current or pending change in ownership structure of the Recipient or subrecipients that increases foreign ownership related to a country of risk. Each notification shall be accompanied by a complete and up-to-date capitalization table showing all equity interests held including limited liability company (LLC) and partnership interests, as well as derivative securities. Include both the number of shares issued to each equity holder, as well as the percentage of that series and of all equity on fully diluted basis. For each equity holder, provide the place of incorporation and the principal place of business, as applicable. If the equity holder is a natural person, identify the citizenship(s);
4. Any current or pending venture capital or institutional investment by an entity that has a general partner or individual holding a leadership role in such entity who has a foreign affiliation with any foreign country of risk;
5. Any current or pending technology licensing or intellectual property sales to a foreign country of risk; and
6. Any changes to the Recipient or the subrecipients' board of directors, including additions to the number of directors, the identity of new directors, as well as each new director's citizenship, shareholder affiliation (if applicable); each notification shall include a complete up-to-date list of all directors (and board observers), including their full name, citizenship and shareholder

affiliation, date of appointment, duration of term, as well as a description of observer rights as applicable.

7. Any proposed changes to the equipment used on the project that would result in:
   a. Equipment originally made or manufactured in a foreign country of risk (including relabeled or rebranded equipment).
   b. Coded equipment where the source code is written in a foreign country of risk.
   c. Equipment from a foreign country of risk that will be connected to the internet or other remote communication system.
   d. Any companies from a foreign country of risk that will have physical or remote access to any part of the equipment used on the project after delivery.

Should DOE determine the connection poses a risk to economic or national security, DOE will require measures to mitigate or eliminate the risk.

DOE has designated the following countries as foreign countries of risk: Iran, North Korea, Russia, and China. This list is subject to change.

Recognizing the disclosures may contain business confidential information, subrecipients may submit their disclosures directly to DOE.

FOREIGN COLLABORATION CONSIDERATIONS (MARCH 2023)

A. Consideration of new collaborations with foreign entities, organizations, and governments. The Recipient must provide DOE with advanced written notification of any potential collaboration with foreign entities, organizations or governments in connection with its DOE-funded award scope. The Recipient must await further guidance from DOE prior to contacting the proposed foreign entity, organization or government regarding the potential collaboration or negotiating the terms of any potential agreement.

B. Existing collaborations with foreign entities, organizations and governments. The Recipient must provide DOE with a written list of all existing foreign collaborations, organizations, and governments in which has entered in connection with its DOE-funded award scope.

C. In general, a collaboration will involve some provision of a thing of value to, or from, the Recipient. A thing of value includes but may not be limited to all resources made available to, or from, the recipient in support of and/or related to the Award, regardless of whether or not they have monetary value. Things of value also may include in-kind contributions (such as office/laboratory space, data, equipment, supplies, employees, students). In-kind contributions not intended for direct use on the Award but resulting in provision of a thing of value from or to the Award must also be reported. Collaborations do not include routine workshops, conferences, use of the Recipient's services and facilities by foreign investigators resulting from its standard published process for evaluating requests for access, or the routine use of foreign facilities by awardee staff in accordance with the Recipient's standard policies and procedures.

ACCESS RESTRICTIONS

The Recipient (including its employees, directors, officers, managers, agents, contractors, vendors, or other representatives, and includes the respective successors or assigns of the foregoing) shall not, and shall ensure that its subsidiaries or affiliates under its control shall not, disclose any information that is not publicly available (including technical data, or any other information that is not publicly available or required to be made public under applicable law or regulation) developed under this DOE-funded project with any subsidiary, affiliate, investor, supplier, licensee at any tier, vendor for Recipient end customers, or joint development partner that: (1) has a place of incorporation or a principal place of business in a Foreign Country of Risk (for entities) or (2) is a national of a Foreign Country of Risk (for individuals). The Recipient shall also ensure that its subsidiaries or affiliates under its control adhere to this same restriction.

The Recipient shall provide on an annual basis and upon request of the DOE Contracting Officer (CO), a certificate of compliance with this term to the CO or designee.

REPORTING SUBAWARD AND EXECUTIVE COMPENSATION (SEPTEMBER 2023)

a. Reporting of first-tier subawards.

1. Applicability. Unless the Recipient is exempt as provided in paragraph d. of this award term, the Recipient must report each action that equals or exceeds $30,000 in Federal funds for a subaward to a non-Federal entity or Federal agency (see definitions in paragraph e. of this award term).

2. Where and when to report.

    i. The non-Federal entity or Federal agency must report each obligating action described in paragraph a.1. of this award term to http://www.fsrs.gov.
    ii. For subaward information, report no later than the end of the month following the month in which the obligation was made. (For example, if the obligation was made on November 7, 2010, the obligation must be reported by no later than December 31, 2010.)

3. What to report. The Recipient must report the information about each obligating action that the submission instructions posted at http://www.fsrs.gov specify.

b. Reporting total compensation of recipient executives for non-Federal entities.

1. Applicability and what to report. The Recipient must report total compensation for each of its five most highly compensated executives for the preceding completed fiscal year, if

    i. The total Federal funding authorized to date under this Federal award is $30,000 or more as defined in 2 CFR 170.320;
    ii. In the preceding fiscal year, the Recipient received:

        a) 80 percent or more of the Recipient's annual gross revenues from Federal procurement contracts (and subcontracts) and Federal financial assistance subject to the Transparency Act, as defined at 2 CFR 170.320 (and subawards); and

b) $25,000,000 or more in annual gross revenues from Federal procurement contracts (and subcontracts) and Federal financial assistance subject to the Transparency Act, as defined at 2 CFR 170.320 (and subawards); and

iii. The public does not have access to information about the compensation of the executives through periodic reports filed under section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a), 78o(d)) or section 6104 of the Internal Revenue Code of 1986. (To determine if the public has access to the compensation information, see the U.S. Security and Exchange Commission total compensation filings at https://www.sec.gov/answers/execomp.htm.)

2. Where and when to report. The Recipient must report executive total compensation described in paragraph b.1. of this award term:

i. As part of the Recipients registration profile at https://www.sam.gov.
ii. By the end of the month following the month in which this award is made, and annually thereafter.

c. Reporting of total compensation of subrecipient executives.

1. Applicability and what to report. Unless the Recipient is exempt as provided in paragraph d. of this award term, for each first-tier non-Federal entity subrecipient under this award, the Recipient shall report the names and total compensation of each of the subrecipient's five most highly compensated executives for the subrecipient's preceding completed fiscal year, if:

i. In the subrecipient's preceding fiscal year, the subrecipient received;

a) 80 percent or more of its annual gross revenues from Federal procurement contracts (and subcontracts) and Federal financial assistance subject to the Transparency Act, as defined at 2 CFR 170.320 (and subawards); and
b) $25,000,000 or more in annual gross revenues from Federal procurement contracts (and subcontracts), and Federal financial assistance subject to the Transparency Act (and subawards); and

ii. The public does not have access to information about the compensation of the executives through periodic reports filed under section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a), 78o(d)) or section 6104 of the Internal Revenue Code of 1986. (To determine if the public has access to the compensation information, see the U.S. Security and Exchange Commission total compensation filings at https://www.sec.gov/answers/execomp.htm.)

2. Where and when to report. The Recipient must report subrecipient executive total compensation described in paragraph c.1. of this award term:

i. To the recipient
ii. By the end of the month following the month during which the Recipient makes the subaward. For example, if a subaward is obligated on any date during the month of October of a given year

(i.e., between October 1 and 31), the Recipient must report any required compensation information of the subrecipient by November 30 of that year.

d. Exemptions
If, in the previous tax year, the Recipient had gross income, from all sources, under $300,000, it is exempt from the requirements to report:

i. Subawards, and
ii. The total compensation of the five most highly compensated executives of any subrecipient.

e. Definitions. For purposes of this award term:

1. *Federal Agency* means a Federal agency as defined at 5 U.S.C. 551(1) and further clarified by 5 U.S.C. 552(f).
2. *Non-Federal entity* means all of the following, as defined in 2 CFR part 25:

   i. A Governmental organization, which is a State, local government, or Indian tribe;
   ii. A foreign public entity;
   iii. A domestic or foreign nonprofit organization; and
   iv. A domestic or foreign for-profit organization.

3. *Executive* means officers, managing partners, or any other employees in management positions.

4. *Subaward*:

   i. This term means a legal instrument to provide support for the performance of any portion of the substantive project or program for which the Recipient received this award and that the recipient awards to an eligible subrecipient.
   ii. The term does not include the Recipient’s procurement of property and services needed to carry out the project or program (for further explanation, see 2 CFR 200.331).
   iii. A subaward may be provided through any legal agreement, including an agreement that the Recipient or a subrecipient considers a contract.

5. *Subrecipient* means a non-Federal entity or Federal agency that:

   i. Receives a subaward from the Recipient under this award; and
   ii. Is accountable to the Recipient for the use of the Federal funds provided by the subaward.

6. *Total compensation* means the cash and noncash dollar value earned by the executive during the recipient's or subrecipient's preceding fiscal year. For more information on disclosure and reporting requirements, see 17 CFR 229.402(c)(2).

POTENTIALLY DUPLICATIVE FUNDING NOTICE (MARCH 2023)

If the Recipient or subrecipients have or receive any other award of federal funds for activities that potentially overlap with the activities funded under this Award, the Recipient must promptly notify DOE in writing of the potential overlap and state whether project funds (i.e., recipient cost share and federal funds) from any of those other federal awards have been, are being, or are to be used (in whole or in part) for one or more of the identical cost items under this Award. If there are identical cost items, the Recipient must promptly notify the DOE Contracting Officer in writing of the potential duplication and eliminate any inappropriate duplication of funding.

IMPACTED INDIAN TRIBES (MAY 2024)

If any activities anticipated to take place under this agreement could potentially impact the resources or reserved rights of Indian Tribe(s), as defined in 25 U.S.C. § 5304 (e), then the recipient/awardee agrees to develop and maintain active and open communications with the potentially impacted Indian Tribe(s), during the period of performance of the agreement, and, if necessary, after the end of the agreement. Approval by DOE must be obtained before any activities take place that could impact Tribal resources or reserved rights, including but not limited to lands, cultural sites, sacred sites, water rights, mineral rights, fishing rights, and hunting rights. The recipient/awardee must coordinate with DOE on all Tribal interactions. DOE will determine if formal government-to-government consultation is needed, and DOE will conduct that consultation accordingly.

- Tribal lands is as defined in 25 U.S.C. §§ 3501(2), (3), (4)(A) and (13).
- Indian Tribe is as defined in 25 U.S.C. § 5304 (e).

REPORTING, TRACKING AND SEGREGATION OF INCURRED COSTS (MARCH 2023)

BIL funds can be used in conjunction with other funding, as necessary to complete projects, but tracking and reporting must be separate to meet the reporting requirements of the BIL and related Office of Management and Budget (OMB) Guidance. The Recipient must keep separate records for BIL funds and must ensure those records comply with the requirements of the BIL.

COMMUNITY BENEFITS OUTCOMES AND OBJECTIVES (APRIL 2024)

The Recipient must meet the stated objectives and milestones set forth in its Community Benefits Outcomes and Objectives, which is incorporated into the Award as an attachment. Reporting on the Recipient's progress towards meeting the objectives and milestones set forth in the Community Benefits Outcomes and Objectives must be submitted in accordance with the Federal Assistance Reporting Checklist, attached to this award.

CYBERSECURITY PLAN (APRIL 2024) (NETL – JUNE 2024)

The Secretary of Energy, per BIL Section 40126, designated the DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) as responsible for coordinating cybersecurity project plans for IIJA provisions the Secretary deemed to have a cyber risk. CESER coordinates with DOE National Laboratory Subject Matter Experts (SMEs) to provide project lifecycle support activities that maintain or improve the project cybersecurity over its lifecycle.

The Recipient is responsible for maintaining and improving project cybersecurity throughout the project period, including responding to DOE feedback on the plans and the associated milestones, deliverables, and attending associated cybersecurity plan lifecycle support meeting dates with CESER and DOE SMEs. The Recipient will revise their Cybersecurity Plan as requested by the DOE, incorporating specified changes within sixty (60) days of receiving notice from the DOE. Any revisions to the cybersecurity plans and all related deliverables shall be emailed securely to CR-IIJACybersecurityplans@hq.doe.gov.

Any DOE and/or National Laboratory review comments or feedback provided to Recipients does not constitute an endorsement or approval of any specific elements within the cybersecurity plan or the proposed security approach. Therefore, such feedback should not be referenced or used in marketing or promotional materials.

All cybersecurity plans and deliverables are exempt from disclosure under the Freedom of Information Act (5 U.S.C. § 552) pursuant to Section 40126(e). This exemption is limited to information provided to or collected by the federal government described in Pub. L. 117-58 § 41026, 42 U.S.C. § 18725.

DAVIS-BACON ACT REQUIREMENTS (NETL - JUNE 2024)

This Award is funded under Division D of the Bipartisan Infrastructure Law (BIL). All laborers and mechanics employed by the recipient, subrecipients, contractors or subcontractors in the performance of construction, alteration, or repair work in excess of $2,000 on a project assisted in whole or in part by funds made available under this Award shall be paid wages at rates not less than those prevailing on similar projects in the locality, as determined by the Secretary of Labor in accordance with Subchapter IV of Chapter 31 of Title 40, United States Code commonly referred to as the "Davis-Bacon Act" (DBA) and its implementing regulations in 29 CFR parts 1, 3, and 5 (collectively the "Davis-Bacon Act Requirements").

Award recipients shall provide written acknowledgement and confirmation of compliance with the Davis-Bacon Act Requirements which include but are not limited to:

1. Ensuring that laborers and mechanics on BIL funded/assisted projects are paid at least the prevailing wage for their work classification on applicable projects.
2. Ensuring that laborers and mechanics on BIL funded/assisted projects are paid on a weekly basis.
3. Ensuring that the applicable wage determination(s) for construction work performed by laborers and mechanics employed by the recipient, subrecipients, contractors, or subcontractors are identified and obtained from the database at www.sam.gov, by 1) selecting "Wage Determinations," then, 2) selecting "Public Buildings and Public Works," then, 3) filtering search results by State (selecting the appropriate state from the drop-down menus), and by County or Independent City (selecting the appropriate County/Independent City from the drop-down menu) in which the work will take place, then, 4) selecting the appropriate construction type (e.g., Building, Residential, Heavy, or Highway). The appropriate wage determination number hyperlink should be selected from the result. If the wage determination which opens lists a "Last Revised Date" after the date of the contract award/start of construction, then scroll to the bottom of the document, and under History, click on the wage determination with the date closest to, but still before the date of contract award/start of construction.
4. Ensuring that applicable wage determination(s) are uploaded to LCPtracker (see below section on LCPtracker).

5. Ensuring that the applicable wage determination(s) and the required contract provisions per 29 CFR 5.5 are flowed down to and incorporated into any applicable contracts/subcontracts or subrecipient awards.
6. Preserving a copy of the applicable wage determination(s) identified and obtained from www.sam.gov, for a period of 3 years after the construction, alteration or repair work herein is completed.
7. Maintaining responsibility for compliance by any lower-tier subcontractors or subrecipients subject to the Davis-Bacon Act Requirements.
8. Receiving and reviewing certified weekly payrolls submitted by all subcontractors and subrecipients for accuracy as needed and identifying potential compliance issues.
9. Maintaining original certified weekly payrolls for 3 years after the completion of the project and making those payrolls available to the Department of Energy or the Department of Labor upon request.
10. Conducting site-visit interviews with employees as needed to provide reasonable assurance of compliance with subcontractors and subrecipients.
11. Cooperating with authorized representatives of the Department of Energy or Department of Labor in the inspection of DBA-related records, on-site interviews of laborers and mechanics, and other reasonable requests related to a DBA investigation.
12. Posting in a prominent and accessible place the applicable wage determination(s) and Department of Labor Publication: WH-1321, Notice to Employees Working on Federal or Federally Assisted Construction Projects.
13. Notifying the Contracting Officer of Davis-Bacon Act Requirement issues, including complaints, violations (as defined in 29 CFR 5.7), disputes (pursuant to 29 CFR parts 4, 6, and 8 and as defined in FAR 52.222-14), disputed DBA-related determinations, Department of Labor investigations, or legal/judicial proceedings related to the Davis-Bacon Act Requirements under this contract, subcontract, or subrecipient award.
14. Preparing and submitting the Semi-Annual Labor Enforcement Report, by April 21 and October 21 of each year, in accordance with the reporting instructions in Attachment 2, Federal Assistance Reporting Checklist.
15. Maintain competency in complying with Davis-Bacon Act Requirements. The Contracting Officer will notify the recipient of any DOE-sponsored Davis-Bacon Act compliance trainings. The Department of Labor offers free Prevailing Wage Seminars several times a year that meet this requirement, at https://www.dol.gov/agencies/whd/government-contracts/construction/seminars/events.

To avoid voluminous attachments under this award, all applicable wage determination(s) included in the www.sam.gov database and uploaded to LCPtracker are incorporated by reference herein as if set forth and attached in full. The applicable wage determination(s) are effective herein even if they have not been attached to the contract/subcontract(s) or subrecipient awards thereunder or have not been correctly identified and obtained from www.sam.gov and/or uploaded to LCPtracker.

The Department of Energy has contracted with LCPtracker, a third-party DBA electronic payroll compliance software application. A waiver for the use of LCPtracker may be granted to a particular contractor or subcontractor if they are unable or limited in their ability to use or access the software.

Davis-Bacon Act Electronic Certified Payroll Submission Waiver

A waiver must be granted before the start of work subject to Davis-Bacon Act requirements (e.g., construction, alteration, or repair work). The recipient does not have the right to appeal DOE's decision concerning a waiver request.

For additional guidance on how to comply with the Davis-Bacon provisions and clauses, see https://www.dol.gov/agencies/whd/government-contracts/construction and https://www.dol.gov/agencies/whd/government-contracts/protections-for-workers-in-construction.

AFFIRMATIVE ACTION AND PAY TRANSPARENCY REQUIREMENTS (SEPTEMBER 2023)

All federally assisted construction contracts exceeding $10,000 annually will be subject to the requirements of Executive Order 11246:

(1) Recipients, subrecipients, and contractors are prohibited from discriminating in employment decisions on the basis of race, color, religion, sex, sexual orientation, gender identity or national origin.

(2) Recipients and Contractors are required to take affirmative action to ensure that equal opportunity is provided in all aspects of their employment. This includes flowing down the appropriate language to all subrecipients, contractors and subcontractors.

(3) Recipients, subrecipients, contractors and subcontractors are prohibited from taking adverse employment actions against applicants and employees for asking about, discussing, or sharing information about their pay or, under certain circumstances, the pay of their co-workers.

The Department of Labor's (DOL) Office of Federal Contractor Compliance Programs (OFCCP) uses a neutral process to schedule contractors for compliance evaluations. OFCCP's Technical Assistance Guide should be consulted to gain an understanding of the requirements and possible actions the recipients, subrecipients, contractors and subcontractors must take. See OFCCP's Technical Assistance Guide at: https://www.dol.gov/sites/dolgov/files/ofccp/Construction/files/ConstructionTAG.pdf?msclkid=9e397d68c4b111ec9d8e6fecb6c710ec.

Additionally, for construction projects valued at $35 million or more and lasting more than one year, Recipients, subrecipients, contractors, or subcontractors may be selected by OFCCP to participate in the Mega Construction Project Program. DOE, under relevant legal authorities including Sections 205 and 303(a) of Executive Order 11246, will require participation as a condition of the award. This program offers extensive compliance assistance with EO 11246. For more information regarding this program, see https://www.dol.gov/agencies/ofccp/construction/mega-program.

CONSTRUCTION SIGNAGE (MAY 2024)

The recipient is encouraged to display DOE Investing in America signage during and after construction. Guidance can be found at: (https://www.energy.gov/design). Proposed signage costs that meet these specifications are an allowable cost and may be included in the proposed project budget.

Division 1-61

IIJA Funding

Request:

Provide the specific investments in the Company's current and/or proposed ISR Plans that are eligible or earmarked for IIJA funding. Indicate the program or project, describe the investments, provide estimated costs that would be incurred by RIE, and amounts that would be received through the IIJA grant.

Response:

The investments in the current ISR Plan that are eligible for IIJA funding are:

- **Smart Capacitors and Regulators** – devices to adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies and increase grid flexibility. The five year planned capital spend for this program is $28,500,000 (Bates Page 53, Row 12).

- **Reclosers** – breaker equipped with a mechanism programmed to automatically close after it has been opened due to a fault, effectively sectionalizing the EPS so fewer customers are affected by any single outage. The five year planned capital spend for the Distribution Automated Recloser Program ("DARP") is $55,970,000 (Bates Page 53, Row 15).

- **Electromechanical Relays** – communication-ready relays that can adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups, aimed to reduce outages and improves restoration time. The five-year planned capital spend for this program is $18,240,000 (Bates Page 53, Row 11).

- **Fiber** – a private fiberoptic network to support communications to substations where it will be used to backhaul information from substations. The current five-year plan for this program is $500,000; however, this will be adjusted once the Fiber Study has been completed (Bates Page 53, Row 16). Prior to undertaking the Fiber Study, the Company's original cost estimate for this project was $48 million spread across three years. Please also see the Company's response to Division 1-57.

Please note, smart capacitors and regulators, electromechanical relays and reclosers all have respective programs in the ISR, but these devices may also be installed as part of Area Study projects, blanket projects, or other programs, such as CEMI-4.

Prepared by or under the supervision of: Nicole Gooding

Division 1-61, page 2

IIJA Funding

The Company has not determined which specific investments of the eligible investments it is going to propose to receive reimbursement for through the IIJA award. The Company can receive up to $50 million, which can be used to offset either Operational Technology ("OT") investments, which are the items listed above and recovered through the ISR, or Information Technology ("IT") investments which are not recovered through the ISR.

Prepared by or under the supervision of: Nicole Gooding

Division 1-62
IIJA Funding

Request:

Explain what IIJA funding covers in terms of capital equipment, engineering, design, construction, removal, overheads, etc. Discuss what specifically is not funded.

Response:

The Company was awarded federal funding to support investments in the following:

- Operational Technology
    - Smart Capacitors and Regulators
    - Reclosers
    - Electromechanical Relays
    - Fiber

- Informational Technology
    - Advanced Distribution Management System (ADMS)
    - Advanced Energy Management System (AEMS)
    - Digital Twin

The Company has not formally accepted the award, and review of cost principles is ongoing. The Company's understanding is that IIJA funding would cover personnel (including all labor such as engineering, construction, etc.), fringe benefits, equipment, contractual, and other (overhead) expenses that will be charged to the projects associated within the grant proposal.

Investments that will receive the IIJA funding must have costs attributable to those investments, which are allowable, allocable, and reasonable and in accordance with the requirements prescribed in Code of Federal Regulations 2 CFR 200 (eCFR :: 2 CFR Part 200 Subpart E -- Cost Principles).

Division 1-63
IIJA Funding

Request:

Is the Company proposing that investments eligible for IIJA funding be approved by the Commission in an ISR Plan, and once implemented, the Company would request IIJA funding?

Response:

Yes, the Company is proposing Operational Technology ("OT") investments in the ISR Plan. Please see the Company's response to Division 1-61 outlining the investments in the FY 2026 Electric ISR Plan that are eligible for IIJA funding. The Company will seek Commission approval for the OT investments in an ISR Plan, install the devices, and then seek reimbursement from the Department of Energy ("DOE") through the IIJA award.

One condition of using federal funding is that the Company must provide non-federal funding in an amount at least equal to the amount of federal funding toward the total cost. The Company's ability to use federal funding to offset costs of the investments is, therefore, dependent on identifying sources of non-federal funding, one of which is cost recovery through the ISR Factor. Please see Attachment DIV 1-60 for the current version of the special terms and conditions that apply to the Company's award, including the non-federal funding requirements tied to the award. As noted in the Company's response to Division 1-60, the Company has not yet formally accepted the award and these special terms and conditions remain pending.

The Company also is planning to invest in reclosers outside of the Electric ISR Plan and will seek Commission approval for recovery of those costs through its next base distribution rate case. The Company also may request reimbursement for these recloser investments as part of its IIJA funding request.

Division 1-64
IIJA Funding

Request:

What occurs from a rate recovery perspective if the Company receives IIJA funding well after the investment has been made and included in rates?

Response:

The Company does not expect that this scenario will occur. The Company has not formally accepted the award; therefore, the agreement terms and conditions related to the timing of IIJA funding are pending. If the award is accepted, the Company will be required to submit requests for reimbursement through the Department of Energy's Service Center as it incurs costs for the eligible investments. The Company would then apply any IIJA reimbursements against the costs of the investments before placing the investment into service and including it in the revenue requirement or rates.

Prepared by or under the supervision of: Nicole Gooding

Division 1-65
IIJA Funding

Request:

Please expand on the statement that funding will be applied "subject to annual regulatory review and approval, as appropriate." (Bates page 43)

Response:

Please see the Company's response to Division 1-63.

Prepared by or under the supervision of: Nicole Gooding

Division 1-66
IIJA Funding

Request:

What is the Company's obligation to make investments under the award agreement?

Response:

The Company has not formally accepted the award, and, as such, the terms and conditions are pending. If the Company accepts the award, the Company will have an obligation to make the investments that it included in the proposal it made to obtain the award. If the Company seeks to change the breadth or scope of the investments, it will need to request a project scope change from the Department of Energy, and the Department of Energy will have discretion to either accept or reject that project scope change and, if it accepts the project scope change, the terms on which it will accept it. For further details, please see the current version of the special terms and conditions, which the Company has provided as Attachment DIV 1-60.

Prepared by or under the supervision of: Nicole Gooding

Division 1-67
IIJA Funding

Request:

Is the Company prioritizing projects selected for IIJA funding based on the project BCA? If not, why?

Response:

No, the Company is not prioritizing projects selected for IIJA funding based on the project BCA. To clarify, the types of investments to which the Company can apply federal funding are already determined; however, the Company has not determined for which specific investments it will seek recovery. This can be a combination of both information technology ("IT") and operational technology ("OT") investments. Please see the Company's response to Division 1-61 for the types of OT investments the Company has included in the FY 2026 Electric ISR Plan for which the Company can seek reimbursement.

Further, the Company reviews and prioritizes its projects based on need. The projects that are eligible for IIJA funding are not included in the FY 2026 Electric ISR Plan because of the potential customer benefit but rather because they are needed to maintain safe and reliable service in the short term or the long term.

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Phone 401-316-7429

Rhode Island Energy™
a PPL company

November 25, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2 (Complete Set)

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's complete set of responses to the Division's Second Set of Data requests in the above-referenced matter.

This transmittal contains the Company's response to Division 2-7, which completes the Company's responses to Division Set 2 in this matter.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: John Bell, Division
Greg Booth, Division
Al Contente, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.
Al Contente, Division

Division 2-1
Area Studies and Long Range Plan (LRP)

Request:

From RIE's perspective, please explain the purpose of the LRP.

Response:

The purpose of the Long Range Plan ("LRP") is to provide both the Company and the Division of Public Utilities and Carriers (the "Division") a ten-year outlook of investments, including Advanced Metering Functionality ("AMF"), to provide a holistic view. The Company will provide this document annually in late August, or early September, prior to the upcoming ISR Plan submittal to the Division.

In addition to the investment plan, the Company summarizes past Area Studies and provides information related to studies that are in flight or are upcoming. The Company does this to provide insight to areas with potential system issues where future investments may be proposed. The Company also includes emerging issues that may be introduced in future ISR Plans such as resiliency and wildfire mitigation, integrated gas and electric planning, and FERC 2222 issues. The LRP provides insight into the Company's planning for its annual ISR Plan filing, and it is not intended to be a reanalysis of the system or a restudy.

Division 2-2
Area Studies and Long Range Plan (LRP)

Request:

Explain how RIE incorporates the results from the Area Studies in the LRP.

Response:

In short, the Company includes the area study solutions in the LRP ten year cash flows, with some adjustments. These adjustments include:

- **Increases for inflation** – Some of the original area study estimates did not include inflationary increases. Adjustments have been made to some of the projects to include inflationary increases. The Company is also adjusting projects using a combination of the Handy Whitman Index and Consumer Price Index.

- **Execution schedules** – As project timelines change, the cash flows in the LRP and subsequent ISR plan filings adjust based on project progression. For example, the East Bay Area Study originally has the Warren Substation project completing in Fiscal Year ("FY") 2023. Because of permitting delays and increased lead times on long lead materials, this project is now scheduled to be completed in FY 2027.

- **Risk Reviews** – The engineering team meets frequently with operations personnel to discuss current system needs, which can lead to acceleration and deceleration of work. For example, the Company has decelerated both the Hospital and Gate II substation projects because of scope changes. Conversely, the Company is looking to accelerate the Auburn and Admiral Street substation projects because there has been increased loading in the area.

The LRP contains a section entitled "Future Study Efforts." This section describes areas that the Company's engineering team has identified need to be restudied. Because the Company has not completed the studies, there are no solutions that can be identified in the LRP. The Company, however, includes "Reserves" for these projects in the outer years, as shown in Attachment 1 - Detailed Long Range Plan.

Division 2-3
Area Studies and Long Range Plan (LRP)

Request:

Explain how RIE reflects the changes in the substation and feeder load forecasts between completion of Area Studies and inclusion in the LRP.

Response:

The Long Range Plan (LRP) is not typically adjusted for any load forecast changes that have occurred after an Area Study has been completed. As mentioned in the Company's response to Division 2-1, the LRP is not intended to be an annual reanalysis or restudy of the Area Study projects. However, the Company does complete an Annual Capacity Review, outlined in Section 2 (Bates Page 9), which would identify an area with lower load than forecasted. If this was the case, the Company would revisit the need for the project.

It is important to note, however, that although some of the Area Study projects are driven by loading issues, many of the area study projects have multiple drivers. For example, projects in the System Capacity & Performance category, such as the East Providence Substation, also have asset condition drivers that would still result in the conclusion that the projects are needed even absent the loading needs.

Division 2-4
Area Studies and Long Range Plan (LRP)

Request:

Explain how RIE considers ongoing changes in system configurations or other improvements that would affect the need and timing of Area Study projects.

Response:

The need for Area Study projects typically does not change. Please see the Company's response to Division 2-3 for an explanation why system changes do not necessarily affect project needs.

While the need for a project typically does not change, the Company often sees the timing of projects shifting during execution. These delays are often outside of the Company's control, such as permitting or material lead times. For example, the distribution line work for the Warren Substation project was delayed for multiple years due to permitting issues, pushing the project in-service date further than the need date outlined in the Area Study.

Prepared by or under the supervision of: Ryan Constable

Division 2-5

Area Studies and Long Range Plan (LRP)

Request:

Explain how RIE updates the need for each project in the LRP or whether the Company incorporates the project as reflected in an Area Study.

Response:

The Company includes the need for each project in the Asset Condition Summaries and System Capacity & Performance Summaries sections in the LRP. Although the summaries provide project needs in the LRP, the Company recommends referencing the area studies for a full explanation of project justification.

In the first LRP submission in September of 2023, the Company included summaries for most of the discretionary projects in the ISR. In subsequent submissions, including the most recent September 2024 submission, the Company only included summaries of new projects or those where there have been significant changes. For example, the Company included the Hospital #146 Equipment Replacement project again this year to highlight a scope change. Similarly, if the need for a project were to change, it would be highlighted in the fact sheets in an upcoming LRP.

Division 2-6
Area Studies and Long Range Plan (LRP)

Request:

Explain how RIE holistically evaluates the interrelationship between projects from each Area Study and optimizes the LRP and project implementation in the ISR Plan.

Response:

The Company included Section 3.3 Managing Overlap and Avoiding Redundancy in the LRP to explain how the Company reviews and evaluates the interrelationships between projects from each Area Study and optimizes the LRP and project implementation in the ISR Plan. When the Company determines that multiple areas have the potential for common system solutions, those areas are combined and/or studied closely together to ensure there is no overlap. The Company also highlights in some fact sheets how it is ensuring there is no overlap and will continue to address this in subsequent LRP submissions. For example, in the most recent LRP, the Chase H. Common – 155F8 Reconductoring fact sheet has a note that says, "The 155F8 was a CEMI circuit. The construction work above has been coordinated with the CEMI work to ensure no overlap of scope." To avoid redundancy, the Company addresses this within the study process by gathering program information and aligning the program recommendation with study.

One example where the Company is finding efficiencies is at the West Greenville Substation. The Company currently is managing and progressing multiple projects concurrently, including Area Study work, 3V0, EMS and Electromechanical Relay Replacements.

Prepared by or under the supervision of: Ryan Constable

Division 2-7

Area Studies and Long Range Plan (LRP)

Request:

What is RIE's confidence level in the projected costs and ability to execute projects at the pace proposed in the LRP, and specifically for Major Projects?

Response:

The Company has high confidence that it can execute projects at the pace proposed in the Long Range Plan (LRP), which includes the Major Projects. The current forecasts provided in the LRP and the FY26 ISR Plan include cash flows that incorporate the increased lead times on materials that the industry has seen over the past few years. The Company also has the design and construction resources available to execute on the proposed plan.

Regarding cost, as the Company and Division have discussed, some of the area study estimates have not been updated for inflation. The Company is working through revising the estimates for these projects, using a combination of the Handy Whitman Indices and the Consumer Price Index. Once this has been completed, the Company will have high confidence that the projected costs will fall within the level of accuracy for the corresponding estimate stage (i.e., +/- 25% for detailed engineering estimates and +/- 10% for construction grade estimates).

Prepared by or under the supervision of: Daniel Glenning

Division 2-8
Area Studies and Long Range Plan (LRP)

Request:

Please provide the Study Area Statistics (Bates page 71) in executable format and expand the chart to include information as illustrated below:

Study Area	No. Planned Projects	Projected % Completed Construction by Year		
		FY 25	FY 26	*Expand to reflect 100% completion for all Study Areas*
Providence				
East Bay				
Central RI East				
South County East				
Blackstone Valley North				
North Central RI				
South County West				
Central RI West				
Tiverton				
Blackstone Valley South				
Newport				

Response:

Please see Attachment DIV 2-8 for the information requested in executable format.

Please note, for the purpose of this model, the Company assumes that construction will be complete for a project in the last fiscal year of spend on the project.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Study Area	No. Planned Projects	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034	FY 2035
1	Providence[1]	30	21%	26%	37%	58%	74%	77%	88%	93%	100%		
2	East Bay[1]	11	0%	0%	82%	91%	91%	100%					
3	Central RI East	2	0%	0%	0%	50%	100%						
4	South County East	8	0%	25%	88%	100%							
5	Blackstone Valley North	2	50%	100%									
6	Northwest Rhode Island[2]	6	0%	33%	67%	83%	100%						
7	South County West	9	0%	22%	33%	33%	78%	89%	100%				
8	Central RI West	13	8%	8%	23%	54%	100%						
9	Tiverton	2	50%	50%	100%								
10	Blackstone Valley South	12	8%	8%	8%	33%	67%	67%	100%				
11	Newport[1]	11	18%	45%	64%	82%	91%	100%					

[1] The numbers provided for the Providence, East Bay and Newport studies are based off the completed Area Studies. This does not include any placeholders or projects that may come from the ongoing restudies.

[2] The Northwest Rhode Island Area Study includes a portion of the Blackstone Valley North and North Central Rhode Island. This does not include any placeholders or projects that may come from the ongoing restudy.

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Rhode Island Energy™
a PPL company

December 6, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3 (Complete Set)

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's complete set of responses to the Division's Third Set of Data requests in the above-referenced matter.

This transmittal completes the Company's responses to the remaining requests to Division Set 3.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosure

cc: John Bell, Division
Greg Booth, Division
Al Contente, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.

Division 3-1
3V0

Request:

Provide an updated list of pending and completed substations under the 3V0 program with the following information:

a) Substation
b) Date complete/Date targeted for completion
c) Actual/projected capital and O&M per installation

Response:

a) through c)

See the table below for the requested information.

Substation	Project Estimate		Actual Spend through 11/1/24		Remaining FY25 forecast		FY26 forecast		3V0 Targeted Completion Date	3V0 Actual Completion Date
	Capex	Opex	Capex	Opex	Capex	Opex	Capex	Opex		
Tiverton	$60,000	$10,000	$60,000	$0	$0	$0	$0	$0	3/31/2019	5/30/2019
Kilvert St.	$40,000	$10,000	$13,978	$0	$0	$0	$0	$0	3/31/2019	12/14/2018
Old Baptist	$40,000	$10,000	$40,000	$0	$0	$0	$0	$0	3/31/2019	12/14/2018
Davisville	$60,000	$10,000	$35,086	$0	$0	$0	$0	$0	3/31/2019	10/21/2020
Wolf Hill	$40,000	$10,000	$60,134	$0	$0	$0	$0	$0	3/31/2020	5/16/2020
Pontiac	$60,000	$10,000	$34,875	$0	$0	$0	$0	$0	3/31/2020	2/21/2020
Riverside	$40,000	$10,000	$322,012	$0	$0	$0	$0	$0	3/31/2020	4/9/2021
Quonset Sub	$430,000	$20,000	$525,000	$0	$0	$0	$0	$0	3/31/2020	6/22/2020
Chopmist	$285,000	$15,000	$287,252	$0	$0	$0	$0	$0	3/31/2021	2/24/2021
Putnam Pike	$90,000	$10,000	$72,734	$0	$0	$0	$0	$0	3/31/2021	6/7/2021
Eldred	$550,000	$50,000	$407,237	$0	$0	$0	$0	$0	3/31/2021	3/30/2021
Peacedale	$427,500	$22,500	$394,025	$0	$0	$0	$0	$0	3/31/2022	3/31/2023
Langworthy	$275,000	$25,000	$475,000	$0	$0	$0	$0	$0	3/31/2022	3/31/2024
Clarkson St	$95,000	$5,000	$343,000	$0	$5,000	$0	$0	$0	3/31/2023	Projected 3/31/2025
TOTAL FORECAST for FY25-FY26					$5,000	$0	$0	$0		

Prepared by or under the supervision of: Ryan Constable

Division 3-2
3V0

Request:

The Company does not propose spend for 3V0 installations in the FY 2026 and future ISR Plan proposals. Is the Company continuing 3V0 implementation? If so, provide the spending category, associated projects and proposed budget. Explain how the Company identifies and prioritizes future installations.

Response:

There Company has no current plans to install 3V0 protection at any substation for fiscal year ("FY") 2026 or in future ISR Plan proposals, except at the West Greenville substation, which is an in-flight project that was approved as part of the FY 2025 ISR plan. The Company has combined the West Greenville 3V0 scope with other scope at the substation and combined all costs under the EMS project. Although the majority of the Company's stations have 3V0 protection, it is possible that the Company may add stations to the program at a later date. The Company determines whether to include substations by comparing maximum generation to minimum load. Aggregate distributed generation approaching more than 50% of the station transformer's minimum load indicates a potentially imminent need for 3V0 protection. If the aggregate distributed generation reaches that level, the Company would add the substation to the program and progress a specific project.

Prepared by or under the supervision of: Ryan Constable

Division 3-3
3V0

Request:

Provide an update on the mobile 3V0 program including how many mobile 3V0 units have been purchased by year, how many have been planned for purchase by year, and actual costs for each purchase.

Response:

During fiscal year ("FY") 2021 and FY 2022, the Company purchased four 3V0 mobile units under this program. The total cost of the project was $712,979. The Company has not purchased any additional mobile 3V0 units, and the Company does not have any plan to acquire additional units.

Prepared by or under the supervision of: Ryan Constable

Division 3-4
Electromechanical Relays

Request:

Consistent with the Commission's FY 2025 ISR Plan Decision No. 14, provide a list of each electromechanical relay forecasted to be replaced in FY 2026, and indicate whether each is being replaced because it is obsolete (not working or can't find spare parts) or if it is being retired early (although it is still working). Include estimated cost for each replacement.

Response:

See table below for the information requested. Please note, this includes both capital and removal costs in the totals. This list does not include electromechanical relays that are being replaced under separate area study projects.

Division 3-4, page 2

Electromechanical Relays

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Station	**Feeder**	**Reason for Replacement**	**Total Cost FY25**	**Total Cost FY26**	**Total Cost FY27**	**Total Cost FY28**
1	**Complete FY26**						
2	Manton Ave	69F1	Obsolete	$12,240	$110,160	$0	
3	Old Baptist	46F1	Retired Early	$12,240	$110,160	$0	
4	Old Baptist	46F2	Obsolete	$12,240	$110,160	$0	
5	Old Baptist	46F3	Obsolete	$12,240	$110,160	$0	
6	Old Baptist	46F4	Obsolete	$12,240	$110,160	$0	
7	**Complete FY27**						
8	Davisville	84T1	Retired Early		$12,240	$110,160	
9	Davisville	84T2	Retired Early		$12,240	$110,160	
10	Davisville	84T3	Obsolete		$12,240	$110,160	
11	Davisville	84T4	Obsolete		$12,240	$110,160	
12	Putnam Pike	38F1	Obsolete		$12,485	$112,363	
13	Putnam Pike	38F2	Obsolete		$12,485	$112,363	
14	Putnam Pike	38F3	Obsolete		$12,485	$112,363	
15	Putnam Pike	38F4	Obsolete		$12,485	$112,363	
16	Putnam Pike	38F5	Retired Early		$12,485	$112,363	
17	Putnam Pike	38F6	Retired Early		$12,485	$112,363	
18	**Complete FY 28**						
19	Franklin Sq.	New Control House	All Obsolete		$332,557	$1,995,347	$997,673

Division 3-5

Electromechanical Relays

Request:

Compare the FY 2025 ISR five-year investment plan to the proposed FY 2026 ISR five-year investment plan for relay replacements. Explain the drivers and justification for the significant increase in spend over the plan period.

Response:

The Fiscal Year ("FY") 2025 ISR five-year investment plan excluded costs associated with the Type 4 (complete rebuild) projects. These Type 4 projects were omitted in the FY 2025 plan because the Company did not feel comfortable providing a cost until quotations were provided from vendors and estimating teams.

The FY 2026 ISR five-year investment plan includes the costs of the Type 4 (complete rebuild) projects based on estimated construction time frames, standards, and work methods that will be utilized when completing this work.

Prepared by or under the supervision of: Gerald Ferris

Division 3-6
Electromechanical Relays

Request:

What is the BCA for electromechanical relay replacements if implemented as proposed from the first year of implementation to FY 2032 (Bates page 95)?

Response:

The BCA for electromechanical relay replacements if implemented as proposed from the first year of implementation to FY 2032 is 3.18 yielding net benefits of $16,701,202.

Division 3-7

Electromechanical Relays

Request:

Provide a list of the approximately 205 electromechanical relays that are proposed for upgrades. Indicate substation, voltage class, assigned category (as discussed on Bates pages 86-87), planned year of replacement, and estimated cost.

Response:

See Attachment DIV 3-7 for the information requested. Please note, the totals in the file include both capital and removal costs.

While the Company was completing this data request, it realized that the proposed capital spend for the program included removal costs. This will be updated in the filing with the Public Utilities Commission. The capital costs for the electromechanical relay replacement program are below.

		(a)	(b)	(c)	(d)	(e)
		FY2026 (000s)	FY2027 (000s)	FY2028 (000s)	FY2029 (000s)	FY2030 (000s)
1	Capital	891	3,275	5,337	3,518	3,225
2	Removal	116	438	641	410	355
3	**Total**	**1,007**	**3,713**	**5,978**	**3,928**	**3,580**

Prepared by or under the supervision of: Gerald Ferris

	(a) Study Area	(b) Substation	(c) Voltage (kV)	(d) Feeder	(e) GMP Relay Replacement Project Type	(f) Count	(g) Relay type	(h) Year Completed	(i) Total Cost to Complete
1	Newport	CLARKE STREET	4.16	65J2	Type 1	Y	Type 1	FY25	$ 120,000
2	Providence	CLARKSON STREET 13	12.47	13F1	Type 2	Y	Type 2	FY28	$ 129,892
3	Providence	CLARKSON STREET 13	12.47	13F10	Type 2	Y	Type 2	FY28	$ 129,892
4	Providence	CLARKSON STREET 13	12.47	13F2	Type 2	Y	Type 2	FY28	$ 129,892
5	Providence	CLARKSON STREET 13	12.47	13F3	Type 2	Y	Type 2	FY28	$ 127,345
6	Providence	CLARKSON STREET 13	12.47	13F4	Type 2	Y	Type 2	FY28	$ 127,345
7	Providence	CLARKSON STREET 13	12.47	13F5	Type 2	Y	Type 2	FY28	$ 127,345
8	Providence	CLARKSON STREET 13	12.47	13F6	Type 2	Y	Type 2	FY28	$ 127,345
9	Providence	CLARKSON STREET 13	12.47	13F7	Type 2	Y	Type 2	FY28	$ 127,345
10	Providence	CLARKSON STREET 13	12.47	13F8	Type 2	Y	Type 2	FY28	$ 127,345
11	Providence	CLARKSON STREET 13	12.47	13F9-BU	Type 2	Y	Type 2	FY28	$ 127,345
12	Providence	CLARKSON STREET 13	12.47	13F9	Type 2	Y	Type 2	FY28	$ 127,345
13	South County East	DAVISVILLE	34.5	84T3	Type 2	Y	Type 2	FY27	$ 122,400
14	South County East	DAVISVILLE	34.5	84T4	Type 2	Y	Type 2	FY27	$ 122,400
15	South County East	DAVISVILLE	34.5	84T1	Type 2	Y	Type 2	FY27	$ 122,400
16	South County East	DAVISVILLE	34.5	84T2	Type 2	Y	Type 2	FY27	$ 122,400
17	Providence	EAST GEORGE ST 77	4.16	77J1	Type 4	Y	Type 4	FY32	$ 302,325
18	Providence	EAST GEORGE ST 77	4.16	77J2	Type 4	Y	Type 4	FY32	$ 302,325
19	Providence	EAST GEORGE ST 77	4.16	77J3	Type 4	Y	Type 4	FY32	$ 302,325
20	Providence	EAST GEORGE ST 77	4.16	77J4	Type 4	Y	Type 4	FY32	$ 302,325
21	Providence	FRANKLIN SQUARE 11	11.5	1107	Type 4	Y	Type 4	FY28	$ 302,325
22	Providence	FRANKLIN SQUARE 11	11.5	1112	Type 4	Y	Type 4	FY28	$ 302,325
23	Providence	FRANKLIN SQUARE 11	11.5	1121	Type 4	Y	Type 4	FY28	$ 302,325
24	Providence	FRANKLIN SQUARE 11	11.5	1123	Type 4	Y	Type 4	FY28	$ 302,325
25	Providence	FRANKLIN SQUARE 11	11.5	1125	Type 4	Y	Type 4	FY28	$ 302,325
26	Providence	FRANKLIN SQUARE 11	11.5	1126	Type 4	Y	Type 4	FY28	$ 302,325
27	Providence	FRANKLIN SQUARE 11	11.5	1139	Type 4	Y	Type 4	FY28	$ 302,325
28	Providence	FRANKLIN SQUARE 11	11.5	1141	Type 4	Y	Type 4	FY28	$ 302,325
29	Providence	FRANKLIN SQUARE 11	11.5	1143	Type 4	Y	Type 4	FY28	$ 302,325
30	Providence	FRANKLIN SQUARE 11	11.5	1149	Type 4	Y	Type 4	FY28	$ 302,325
31	Providence	FRANKLIN SQUARE 11	11.5	1153	Type 4	Y	Type 4	FY28	$ 302,325
32	Newport	HARRISON	4.16	32J12	Type 4	Y	Type 4	FY32	$ 302,325
33	Newport	HARRISON	4.16	32J2	Type 4	Y	Type 4	FY32	$ 302,325
34	Newport	HARRISON	4.16	32J4	Type 4	Y	Type 4	FY32	$ 302,325
35	Newport	HARRISON	4.16	32J14	Type 4	Y	Type 4	FY32	$ 302,325
36	South County West	KENYON 68	12.47	68F1	Type 2	Y	Type 2	FY29	$ 129,892
37	South County West	KENYON 68	12.47	68F2	Type 2	Y	Type 2	FY29	$ 129,892
38	South County West	KENYON 68	12.47	68F3	Type 2	Y	Type 2	FY29	$ 129,892
39	South County West	KENYON 68	12.47	68F4	Type 2	Y	Type 2	FY29	$ 129,892
40	South County West	KENYON 68	12.47	68F5	Type 2	Y	Type 2	FY29	$ 129,892
41	Central RI East	LINCOLN AVENUE 72	12.47	72F1	Type 2	Y	Type 2	FY25	$ 127,345
42	Central RI East	LINCOLN AVENUE 72	12.47	72F2	Type 2	Y	Type 2	FY25	$ 127,345
43	Central RI East	LINCOLN AVENUE 72	12.47	72F3	Type 2	Y	Type 2	FY25	$ 127,345
44	Central RI East	LINCOLN AVENUE 72	12.47	72F4	Type 2	Y	Type 2	FY25	$ 127,345
45	Central RI East	LINCOLN AVENUE 72	12.47	72F5	Type 2	Y	Type 2	FY25	$ 127,345
46	Central RI East	LINCOLN AVENUE 72	12.47	72F6	Type 2	Y	Type 2	FY25	$ 127,345
47	Providence	LIPPITT HILL 79	12.47	79F1	Type 3	Y	Type 3	FY28	$ 191,017
48	Providence	LIPPITT HILL 79	12.47	79F2	Type 3	Y	Type 3	FY28	$ 191,017
49	North Central RI	MANTON 69	12.47	69F1	Type 1	Y	Type 1	FY26	$ 122,400
50	South County East	OLD BAPTIST ROAD 46	12.47	46F1	Type 2	Y	Type 2	FY26	$ 122,400
51	South County East	OLD BAPTIST ROAD 46	12.47	46F2	Type 2	Y	Type 2	FY26	$ 122,400
52	South County East	OLD BAPTIST ROAD 46	12.47	46F3	Type 2	Y	Type 2	FY26	$ 122,400
53	South County East	OLD BAPTIST ROAD 46	12.47	46F4	Type 2	Y	Type 2	FY26	$ 122,400
54	Blackstone Valley South	PAWTUCKET #2	4.16	148J1	Type 3	Y	Type 3	FY28	$ 191,017
55	Blackstone Valley South	PAWTUCKET #2	4.16	148J3	Type 3	Y	Type 3	FY28	$ 191,017
56	Blackstone Valley South	PAWTUCKET #2	4.16	148J5	Type 3	Y	Type 3	FY28	$ 191,017
57	Blackstone Valley South	PAWTUCKET #2	4.16	148J7	Type 3	Y	Type 3	FY28	$ 191,017
58	North Central RI	PUTNAM PIKE 38	12.47	38F1	Type 2	Y	Type 2	FY27	$ 124,848
59	North Central RI	PUTNAM PIKE 38	12.47	38F2	Type 2	Y	Type 2	FY27	$ 124,848

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Study Area	Substation	Voltage (kV)	Feeder	GMP Relay Replacement Project Type	Count	Relay type	Year Completed	Total Cost to Complete
60	North Central RI	PUTNAM PIKE 38	12.47	38F3	Type 2	Y	Type 2	FY27	$ 124,848
61	North Central RI	PUTNAM PIKE 38	12.47	38F4	Type 2	Y	Type 2	FY27	$ 124,848
62	North Central RI	PUTNAM PIKE 38	12.47	38F5	Type 2	Y	Type 2	FY27	$ 124,848
63	North Central RI	PUTNAM PIKE 38	12.47	38F6	Type 2	Y	Type 2	FY27	$ 124,848
64	Blackstone Valley North	RIVERSIDE 8	13.8	108W51	Type 4	Y	Type 4	FY31	$ 302,325
65	Blackstone Valley North	RIVERSIDE 8	13.8	108W53	Type 4	Y	Type 4	FY31	$ 302,325
66	Blackstone Valley North	RIVERSIDE 8	13.8	108W55	Type 4	Y	Type 4	FY31	$ 302,325
67	Blackstone Valley North	RIVERSIDE 8	13.8	108W60	Type 4	Y	Type 4	FY31	$ 302,325
68	Blackstone Valley North	RIVERSIDE 8	13.8	108W61	Type 4	Y	Type 4	FY31	$ 302,325
69	Blackstone Valley North	RIVERSIDE 8	13.8	108W62	Type 4	Y	Type 4	FY31	$ 302,325
70	Blackstone Valley North	RIVERSIDE 8	13.8	108W63	Type 4	Y	Type 4	FY31	$ 302,325
71	Blackstone Valley North	RIVERSIDE 8	13.8	108W65	Type 4	Y	Type 4	FY31	$ 302,325
72	Blackstone Valley North	STAPLES 112	13.8	112C45	Type 3	Y	Type 3	FY29	$ 194,838
73	Blackstone Valley North	STAPLES 112	13.8	112W41	Type 3	Y	Type 3	FY29	$ 194,838
74	Blackstone Valley North	STAPLES 112	13.8	112W42	Type 3	Y	Type 3	FY29	$ 194,838
75	Blackstone Valley North	STAPLES 112	13.8	112W43	Type 3	Y	Type 3	FY29	$ 194,838
76	Blackstone Valley North	STAPLES 112	13.8	112W44	Type 3	Y	Type 3	FY29	$ 194,838
77	Blackstone Valley South	VALLEY	13.8	102C43	Type 4	Y	Type 4	FY29	$ 302,325
78	Blackstone Valley South	VALLEY	13.8	102C53	Type 4	Y	Type 4	FY29	$ 302,325
79	Blackstone Valley South	VALLEY	13.8	102W41	Type 4	Y	Type 4	FY29	$ 302,325
80	Blackstone Valley South	VALLEY	13.8	102W42	Type 4	Y	Type 4	FY29	$ 302,325
81	Blackstone Valley South	VALLEY	13.8	102W44	Type 4	Y	Type 4	FY29	$ 302,325
82	Blackstone Valley South	VALLEY	13.8	102W50	Type 4	Y	Type 4	FY29	$ 302,325
83	Blackstone Valley South	VALLEY	13.8	102W51	Type 4	Y	Type 4	FY29	$ 302,325
84	Blackstone Valley South	VALLEY	13.8	102W52	Type 4	Y	Type 4	FY29	$ 302,325
85	Blackstone Valley South	VALLEY	13.8	102W54	Type 4	Y	Type 4	FY29	$ 302,325
86	South County East	WAKEFIELD 17	12.47	17F1	Type 1	Y	Type 1	FY25	$ 122,400
87	South County East	WAKEFIELD 17	12.47	17F2	Type 1	Y	Type 1	FY25	$ 122,400
88	South County East	WAKEFIELD 17	12.47	17F3	Type 1	Y	Type 1	FY25	$ 122,400
89	East Bay	WARREN 5	12.47	5F1	Type 2	Y	Type 2	FY28	$ 124,848
90	East Bay	WARREN 5	12.47	5F2	Type 2	Y	Type 2	FY28	$ 124,848
91	East Bay	WARREN 5	12.47	5F3	Type 2	Y	Type 2	FY28	$ 124,848
92	East Bay	WARREN 5	12.47	5F4	Type 2	Y	Type 2	FY28	$ 124,848
93	Blackstone Valley South	WASHINGTON	13.8	126W40	Type 4	Y	Type 4	FY30	$ 302,325
94	Blackstone Valley South	WASHINGTON	13.8	126W41	Type 4	Y	Type 4	FY30	$ 302,325
95	Blackstone Valley South	WASHINGTON	13.8	126W42	Type 4	Y	Type 4	FY30	$ 302,325
96	Blackstone Valley South	WASHINGTON	13.8	126W50	Type 4	Y	Type 4	FY30	$ 302,325
97	Blackstone Valley South	WASHINGTON	13.8	126W51	Type 4	Y	Type 4	FY30	$ 302,325
98	Blackstone Valley South	WASHINGTON	13.8	126W53	Type 4	Y	Type 4	FY30	$ 302,325
99	Blackstone Valley South	WASHINGTON	13.8	126W54	Type 4	Y	Type 4	FY30	$ 302,325
100	Newport	WEST HOWARD	4.16	154J14	Type 3	Y	Type 3	FY30	$ 198,735
101	Newport	WEST HOWARD	4.16	154J16	Type 3	Y	Type 3	FY30	$ 198,735
102	Newport	WEST HOWARD	4.16	154J18	Type 3	Y	Type 3	FY30	$ 198,735
103	Newport	WEST HOWARD	4.16	154J2	Type 3	Y	Type 3	FY30	$ 198,735
104	Newport	WEST HOWARD	4.16	154J4	Type 3	Y	Type 3	FY30	$ 198,735
105	Newport	WEST HOWARD	4.16	154J6	Type 3	Y	Type 3	FY30	$ 198,735
106	Newport	WEST HOWARD	4.16	154J8	Type 3	Y	Type 3	FY30	$ 198,735
107	North Central RI	WOLF HILL	23kV	2219	Type 1	Y	Type 1	FY28	$ 125,000
108	North Central RI	WOLF HILL	23kV	2221	Type 1	Y	Type 1	FY28	$ 125,000

Program	
Type 1	7
Type 2	40
Type 3	18
Type 4	43
Total	108

Division 3-8

Electromechanical Relays

Request:

How did the Company derive relay replacement cost estimates and when were they developed? Include in the explanation if the estimate is based on completely new panels or a significant rework of existing panels.

Response:

The Company developed the cost estimates for relay replacements using actual costs from similar projects it completed previously. The first step was addressing the different types of substation architecture used in the Rhode Island system and dividing the work into those categories.

Cost estimates for Type 1, Type 2 and Type 3 were developed in FY24. Type 4 was given a high level cost in FY25.

Type 1 projects use an existing standard relay enclosure that is added to the substation yard. The old relays are removed from service and new cables, and wires are run from the substation breakers and other ancillary equipment to the new standard relay enclosure. The existing remote terminal unit ("RTU") is updated to support the new inputs and outputs (I/O), and the entire package is tested and returned to service. For Type 1 estimates, the Company used the cost of the required hardware as the basis and added in typical costs for engineering and construction. Then the Company applied an annual inflation rate to account for the year-to-year increases in labor and material costs.

Type 2 projects are like Type 1 projects with the sole exception being that the new relays have to be fit to a custom-made plate that is installed into the existing circuit breaker. This is done where there are space constraints and extra cabinets in the substation yard that pose a safety risk to workers. The Company created Type 2 estimates similarly to Type 1 estimates, with the assumption that the cost of a custom plate would be equal to the entire enclosure included in the Type 1 estimate. All other major components are the same.

Type 3 projects typically are related to indoor or switchgear substations where the relays are affixed to a cabinet door usually located above the circuit breaker. In these substations, significant rework of the existing cabinet door is required. The rework of the door typically includes a custom-made plate that is affixed to the door as a new skin once the old relays have been removed. For Type 3 estimates, the Company used the material costs from an actual 2022 project replacing a panel line up. The Company adjusted those costs to factor in several variances with ancillary equipment, removed transformer protection packages and then adjusted for inflation and divided equally across the number of distribution feeder breakers.

Prepared by or under the supervision of: Gerald Ferris

Division 3-8, page 2

Electromechanical Relays

Type 4 projects are those that require a complete substation rebuild because there is not adequate space and or ancillary systems present to support a microprocessor relay installation. Each of these projects will require a custom solution that may include portions of any of the above project types. For Type 4 estimates, the Company used actual costs for several recent rebuild projects and a new build project to develop an average cost for a new station. The Company adjusted this average cost for inflation and divided by the number of feeders served to come up with a per feeder breaker cost.

Division 3-9

Electromechanical Relays

Request:

What is the typical project timeline from design to completion for relay replacements? What is the lead time to procure digital relays? Has the Company observed supply chain issues or significant cost increases since the time the program was developed?

Response:

Once approved, the projects move into engineering immediately. It takes about six weeks to move though the process of scoping, bidding, awarding and onboarding an engineering and design firm. The duration of engineering on the fiscal year ("FY") 2025 approved projects has been approximately five-and-a-half months. This time frame is highly dependent on the complexity of the design associated with integrating the existing ancillary systems at the substation. The Company procures major materials having a long lead time, early in the engineering phase. These major materials have delivery times in the 6-month range currently. The Company orders all minor materials at the completion of the design phase, which typically are ready in a few weeks. Upon receipt of a complete installation package, the project moves to construction. The installation time is approximately 4 days per feeder position, followed by a day for testing and commissioning. There are other factors that affect the actual installation schedule because system loading may not permit necessary outages at the moment the Company receives design packages. As such, it is impossible to give an exact duration on construction at this time. The Company anticipates completing all the approved FY2025 relay replacements by March 31, 2025, based on current progress.

In light of the above, a reasonable expected timeframe for Type 1 and Type 2 relay replacements is 12-14 months.

Type 3 and Type 4 relay replacements are more complex and require more time to design and execute. The Company currently anticipates a 16-18 month timeframe to complete Type 3 relay replacements. Type 4 relay replacements will follow a time frame that is more typical of station asset condition rebuilds because the entire station will require analysis before moving forward.

Division 3-10

Smart Capacitors and Regulators (VVO/CVR)

Request:

The Company proposes smart capacitors and regulators on circuits originating from the Johnston Substation (Bates page 37). Confirm that there are ten 12.47 KV circuits originating from Johnston Substation. Identify the circuits proposed for the program and how the Company prioritized the substation and associated work.

Response:

This project will include modifying the substation regulator controls, replacing existing capacitors and controls, and installing new capacitors on the ten Johnston circuits. The project scope includes the replacement/upgrade of 41 existing capacitors banks and the installation of 26 new capacitor banks across the ten feeders: 18F5, 18F6, 18F7, 18F8, 18F9, 18F10, 18F11, 18F12, 18F13, 18F14.

The Company prioritizes stations for the Volt-var Optimization Program through a screening tool that estimates costs and benefits. The Company selects the highest value stations first, subject to consultation with Operations and the Control Center, as well as consideration of other area work. Also see the response to Division 3-11.

Prepared by or under the supervision of: Ryan Constable

Division 3-11

Smart Capacitors and Regulators (VVO/CVR)

Request:

Consistent with the Commission's FY 2025 ISR Plan Decision No. 17, provide a benefit cost analysis specific to each circuit proposed under the VVO program.

Response:

The Company notes that the reference to the benefit cost analysis in this request is contained in the Commission's FY 2025 ISR Plan Decision No. 18.

The Company is completing the documentation consistent with the Commission's FY 2025 ISR Plan Decision No. 18 for a benefit-cost analysis specific to each circuit proposed under the VVO program and will include this documentation in its FY 2026 ISR filing with the Commission.

Preliminary benefit-cost analysis includes the station screening as shown in Figure DIV 3-11-1.

Figure DIV 3-11-1

Substation	Customer Value (NPV $Ms)	Energy Savings ($Ms)	Peak (Capacity) Savings ($Ms)	DRIPE Energy Savings ($Ms)	DRIPE Capacity Savings ($Ms)	Capex Cost ($Ms)	% Estimated Energy Savings
JOHNSTON 18	$2.67	$5.04	$1.36	$0.14	$0.14	$2.90	2.75%

The preliminary energy saving per circuit is shown in Figure 3-11-2.

Division 3-11, page 2
Smart Capacitors and Regulators (VVO/CVR)

Figure 3-11-2

Feeders	Before Optimization (MWh)	After Optimization (MWh)	% Energy Reduction
18F5	41,300	40,600	1.69%
18F6	37,400	36,530	2.33%
18F7	35,325	34,214	3.15%
18F8	23,679	23,043	2.69%
18F9	44,449	43,441	2.27%
18F10	24,460	23,510	3.88%
18F11	44,437	42,920	3.41%
18F12	10,340	10,053	2.78%
18F13	30,758	29,760	3.24%
18F14	21,937	21,363	2.62%
TOTAL	**314,085**	**305,434**	**2.75%**

Division 3-12
Overloaded Transformers

Response:

The annual budget for distribution Overloaded Transformer Replacements is $1.5 million through FY 2030. How is this budget derived and how are recent significant increases in unit prices reflected in the budget? Is the level of work declining each year? Additionally, explain how the AMF meter replacement and data will enhance the accuracy of the program need.

Response:

The Company has kept the Overloaded Transformer Replacement program at $1.5 million annually, and has not taken increases in unit prices into consideration. The Company reviews the proposed ISR budget holistically and determines appropriate levels for each project and program from a need, affordability, and execution perspective.

The program has been in place for a number of years, and the number of pole top single and multiphase transformers replacements is declining each year. In addition, over the last few years, the Company also has moved to eliminating step-down transformers under this program. Although the work is declining, the Company anticipates the need for the program through at least FY 2030.

Without AMF meters and data, each customer's monthly peak load power is calculated using each customer's monthly energy consumption with fixed assumptions to enable the conversion of energy to power data. These fixed assumptions can lead to under- or over-estimation of each customer's monthly peak load power. For each transformer, the customers' monthly peak load power data is summed together to get the undiversified transformer monthly peak load. Because the customers' monthly peak load data is non-coincident, each transformer's monthly peak power is reduced by an assumed transformer load diversity factor. This assumed transformer load diversity factor can result in under- or over-estimating the transformer monthly peak load power and loading.

With AMF meters and data, the customer load power will be measured directly rather than estimated with customer monthly energy consumption, eliminating the inaccuracy that results from the assumptions used to convert the customer monthly energy consumption to the customer monthly peak load. Due to the increased frequency of data collection, each transformer's customer coincident load data can be summed and then the coincident transformer load power can be evaluated directly to determine the transformer peak load power and loading. This eliminates the inaccuracy of applying an assumed transformer load diversity factor to the undiversified sum of the non-coincident customer monthly peak load data.

Prepared by or under the supervision of: Ryan Constable

Division 3-13
EMS/RTU

Request:

Provide the locations and planned work for EMS/RTU (SCADA) additions for FY 2026 through FY 2028. Explain how the Company determined the need and prioritization of the additions.

Response:

The Company has planned EMS/RTU (SCADA) additions at East George, West Greenville and Wampanoag substations for FY 2026 through FY 2028 under the System Capacity and Performance EMS/RTU Program ISR Grouping. The Company also has planned EMS/RTU (SCADA) additions at other substations through projects under other Spending Rationales and ISR groupings.

The Company often prioritizes EMS/RTU additions planned under the EMS/RTU Program or other Spending Rationales and ISR groupings at substations where it is performing other planned work. For example, at West Greenville substation, there is the need for air break switch replacement, transfer scheme control replacement, relay replacement, and 3V0 installation. There is planned breaker replacement work at Wampanoag substation. Because West Greenville substation and Wampanoag substation also would benefit from reliability improvements, increased operational effectiveness, and telemetry provided by EMS/RTU additions, the Company planned EMS/RTU additions under the EMS/RTU Program to leverage existing construction schedules and coordination. Outside of the EMS/RTU Program, the Company plans EMS/RTU additions as part of other projects in separate ISR groupings. For example, because the Company is rebuilding Apponaug and Centredale substation to address asset conditions issues, the Company added EMS/RTU additions to the Apponaug and Centredale Substation Rebuild project scopes.

The Company also prioritizes EMS/RTU additions under the EMS/RTU Program at substations that are planned to remain in service and can benefit from reliability improvements, increased operational effectiveness, and telemetry provided by EMS/RTU additions. For example, because East George substation is one of the only 4.16kV substations that will remain in service in Providence, the Company has planned EMS/RTU additions there under the EMS/RTU Program.

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Division 3-14
EMS/RTU

Request:

The LRP does not include EMS/RTU spend after FY 2028. Will the Company have completed SCADA additions at all targeted substations by FY 2028?

Response:

With the EMS/RTU additions planned under the EMS/RTU program and under other spending rationales and ISR groupings, the Company is quickly approaching the completion of EMS/RTU additions at nearly all active substations that are to remain in service. All planned work that includes EMS/RTU additions is estimated to be completed by FY 2030. Manton substation is the only active substation to remain in service without any current plans for EMS/RTU additions.

Prepared by or under the supervision of: Ryan Constable

Division 3-15
Mobile Substation

Request:

The Company proposes expending $3.8M in FY26 and $7.7M in FY27 for 3 mobile substations and 1 mobile regulator to be delivered in FY28. Does the proposed expenditure capture all anticipated costs to acquire and store the equipment? Is the Company planning to make additional mobile substation purchases?

Response:

Yes, the FY 2026 Electric ISR Plan, which proposes expending $3.8M in FY 2026 and $7.7M in FY 2027 for 3 mobile substations and 1 mobile regulator to be delivered in FY 2028, includes all the costs to acquire and store that equipment, including preparing an area to store the mobile substations.

Currently, the Company does not have a plan to make additional mobile substation purchases.

Division 3-16

Spare Power Transformers

Request:

In executable format, please provide an updated list of proposed spare transformer purchases (consistent with response to FY 2025 ISR Plan, Record Request No. 1). Indicate actual spend by year and proposed delivery date for transformers that have been ordered. Identify the eight transformers that are the result of parting ways with National Grid.

Response:

For the information requested, please see the Excel version of Attachment DIV 3-16.

The Company removed the cost for one transformer in row (17) that is no longer needed.
The Company also revised the construction estimates in row (24) to reflect updated foundation and fence cost estimates.

The total proposed spend by Fiscal Year is shown in row (25). The Company has not yet ordered the spare transformers approved during the FY 2025 ISR and, therefore, cannot provide actual spend to date. The estimated final delivery date is shown in column (k) for each of the transformers.

There are eight (8) spare transformers identified below that are needed because the Company no longer has access to common spare transformers owned by National Grid's Massachusetts affiliate; however, the costs for those common transformers were not allocated to the Company when it was part of the National Grid organization.

These eight transformers were owned by National Grid's Massachusetts affiliate at the time PPL Rhode Island Holdings, LLC, acquired the Company and would have been available to the Company if the Company had remained under National Grid ownership; however, the Company would have incurred costs for these transformers if/when it used them.

These eight transformers are described below and identified in the attached spreadsheet highlighted in yellow:

- Two (2) 115kV/13.2kV 55 MVA LTC transformers.
- Three (3) 115kV/13.2kV 40 MVA LTC transformers.
- One (1) 115kV/34.5kV 55 MVA transformer.
- One (1) 69kV/13.8kV 40 MVA LTC transformer.
- One (1) 23kV/13.2kV 25 MVA LTC transformer.

Prepared by or under the supervision of: Gerald Ferris

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			Spare Transformer Purchases								
	Voltage and Rating	**Winding Configuration**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total Cost ($) per Transformer**	**Est. Delivery Date**
(1)	115-13.2kV 33/44/55 LTC	Delta-Wye	$200,000	$1,200,000	$600,000					**$2,000,000**	FY27
(2)	115-13.2kV 33/44/55 LTC	Delta-Wye				$200,000	$1,200,000	$600,000		**$2,000,000**	FY30
(3)	115-13.2 24/32/40 LTC	Delta-Wye		$200,000	$1,200,000	$600,000				**$2,000,000**	FY28
(4)	115-13.2 24/32/40 LTC	Delta-Wye			$200,000	$1,200,000	$600,000			**$2,000,000**	FY29
(5)	115-13.2 24/32/40 LTC	Delta-Wye					$200,000	$1,200,000	$600,000	**$2,000,000**	FY31
(6)	115-34.5kV 48/64/80	Delta-Wye		$270,000	$1,620,000	$810,000				**$2,700,000**	FY28
(7)	115-34.5kV 33/44/55	Wye-Wye					$200,000	$1,200,000	$600,000	**$2,000,000**	FY31
(8)	115-34.5kV 33/44/55	Delta-Wye					$200,000	$1,200,000	$600,000	**$2,000,000**	FY31
(9)	115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta					$200,000	$1,200,000	$600,000	**$2,000,000**	FY31
(10)	115-34.5-13.8 24/32/40 MVA	Wye-Wye			$180,000	$1,080,000	$540,000			**$1,800,000**	FY29
(11)	115-23kV 30/40/50	Delta-ZigZag			$180,000	$1,080,000	$540,000			**$1,800,000**	FY29
(12)	115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta		$200,000	$1,200,000	$600,000				**$2,000,000**	FY28
(13)	69-13.8kV 24/32/40 LTC	Delta-Wye	$160,000	$960,000	$480,000					**$1,600,000**	FY27
(14)	69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta				$160,000	$960,000	$480,000		**$1,600,000**	FY30
(15)	33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye			$180,000	$1,080,000	$540,000			**$1,800,000**	FY29
(16)	34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye			$60,000	$360,000	$180,000			**$600,000**	FY29
(17)	34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag								**$600,000**	-
(18)	34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	$120,000	$720,000	$360,000					**$1,200,000**	FY27
(19)	23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye		$140,000	$840,000	$420,000				**$1,400,000**	FY28
(20)	23-11.5kV 10/12.5MVA	ZigZag-Delta				$60,000	$360,000	$180,000		**$600,000**	FY30
(21)	22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye				$80,000	$480,000	$240,000		**$800,000**	FY30
		Count	**3**	**4**	**5**	**4**	**4**				
(22)	8 transformers highlighted in DIV 3-16	**Total Material Cost ($) per FY**	**$480,000**	**$3,690,000**	**$7,100,000**	**$7,730,000**	**$6,200,000**	**$6,300,000**	**$2,400,000**	**$34,500,000**	
(23)		**Total Engineering Cost ($) per FY**	**$60,000**	**$170,000**	**$75,000**	**$45,000**	**$25,000**	**$0**	**$0**	**$375,000**	
(24)		**Total Construction Cost ($) per FY**	**$0**	**$0**	**$1,719,145**	**$459,425**	**$0**	**$0**	**$0**	**$2,178,570**	
(25)		**Total Overall Cost ($) per FY**	**$540,000**	**$3,860,000**	**$8,894,145**	**$8,234,425**	**$6,225,000**	**$6,300,000**	**$2,400,000**	**$37,053,570**	

Division 3-17
Spare Power Transformers

Request:

Discuss any changes to the Company's spare transformer program as originally proposed and resulting impacts on the types or amounts of proposed purchases.

Response:

The Company has reduced the total number of transformers in the program from 21 to 20. In consultation with Substation Engineering group, the Company determined it could engineer around the need to purchase the 34.5 Kilovolt (kV) to 12.47 kV, 9.345 MVA transformer with a winding configuration of Delta Zigzag.

Additionally, as part of the annual spare transformer review that considers upcoming projects, condition asset reports, and updated Poisson calculations, the Company has adjusted the timing of two transformer purchases. The Company has accelerated the purchase of a 115 kV to 34.5 kV with a 13.8 kV tertiary winding, 40 MVA transformer to FY 2027 from FY 2028. The Company has also delayed the purchase of the 22.9 kV to 4.16 kV, 9.375 MVA transformer until FY 2028 (instead of FY 2027).

Division 3-18
Spare Power Transformers

Request:

What is the current lead time for spare transformers? Does the lead time vary depending on the transformer specification (e.g. a lower voltage or smaller size transformer may have shorter lead time)? If so, please re-calculate the spare transformer requirements the models using reduced lead times for lower voltage transformers and provide results compared to the Company's previous model.

Response:

The current lead time for spare transformers is 36 months and does not vary depending on the transformer specification. The Company has requested specifications and quotations from multiple vendors and expects to receive these with lead times in January 2025. If the Company finds that lead times vary by transformer specification, the Poisson calculation will be updated accordingly.

Because this lead time has not changed for spare transformers, there is no need to recalculate the spare transformer requirement.

Division 3-19

Vegetation Management

Request:

Regarding additional vegetation clearing to create ROW access points for wildfire prevention, how are the locations and planned work being coordinated with potential risk areas and the Company's overall strategy which will not be complete until early 2025? (Bates page 73)

Response:

The Company's forestry department uses the data from both internal and external sources to optimize the work that is planned on each circuit for the upcoming fiscal year. This data analysis now includes a review to determine the need for additional vegetation clearing to create ROW access points for wildfire prevention. As a future circuit is planned for risk reduction work, the wildfire data can help prescribe additional vegetation work that will benefit wildfire prevention and improve wildfire suppression.

While the full wildfire strategy will not be complete until early 2025, the Company determined that additional vegetation clearing to create ROW access points is a way to quickly implement wildfire mitigation strategies efficiently, effectively, and with consistency going forward.

Division 3-20
Vegetation Management

Request:

How will access points be maintained and who is responsible for future work and costs?

Response:

The Company is engaging property owners and other stakeholders about clearing access points and explaining the benefits of this additional vegetation work for their property. The enhancements the Company is planning are small, such as removing trees or brushy vegetation to help gain equipment access. This initiative will not include larger scope enhancements, such as building stone access roads or conducting earth moving.

The Company could be responsible for future work; however, future costs for these access points should be minimal, especially because the enhanced access can change the type of vegetation maintenance performed in the future. For example, if a single-phase tap was pruned previously with a climbing crew and now can be accessed by a bucket crew, this will reduce costs.

Prepared by or under the supervision of: Christopher Rooney

Division 3-21

Vegetation Management

Request:

Explain the level of coordination with other agencies such as Corp of Engineers, Fish and Wildlife; RI Department of Environmental Management; Division of Forest Environment and others.

Response:

The Company coordinates its vegetation management program with state and federal agencies in two different ways.

First, the Company engages agencies to provide input on the Company's vegetation management strategy and program design, especially as different situations arise. The Company does this to ensure environmental issues are being addressed in the execution of the program. For example, recently the long-eared brown bat is now labeled as an endangered species, when before it was threatened. The Company is meeting and coordinating with the Rhode Island Department of Environmental Management's Fish and Wildlife department, as well as the US Department of Agriculture's Fish and Wildlife Service on how to avoid the bats and reduce potential harm to the species. Another example of coordinating with agencies is related to the heightened focus and discussions on wildfire mitigation. The Company recently met with the Rhode Island Division of Forest Environment's Wildland Fire Control department to exchange ideas and discussed the potential for the Company to use their wildfire risk tool to prescribe vegetation work more precisely. As a final example, in March 2024, Rhode Island Energy coordinated with the Coastal Resources Management Council technical staff to update the language in the three-year permit authorization for routine maintenance activities to include the cutting of vegetation.

In addition to high-level strategy discussions, the Company also has site specific consultation and coordination with agencies. For example, the Company submits permits to do specific tree work in wetlands where the Department of Environmental Management and the Army Corp of Engineers have jurisdiction. The Company also works with agencies when conducting vegetation management on their actual properties. Recently the Company worked with the Army National Guard to enhance the reliability of Camp Fogarty in East Greenwich's main feed.

Prepared by or under the supervision of: Christopher Rooney

Division 3-22
URD/UG Cable Replacement

Request:

How has the Company's budget been adjusted for the increased cost in underground primary cable and does this increase mean a substantial reduction in line footage replacement?

Response:

The Company has not adjusted its recent budgets for the increased cost in underground primary cable. The Company reviews the proposed ISR budget holistically and determines appropriate levels for each project and program from a need, affordability and execution perspective.

The FY 2025 budget for the UG Program is $5.5 million, and the Company is planning to replace approximately 27,000 feet of cable. The FY 2026 proposed budget is $4.5 million, and, although the exact projects have not been determined, the footage replaced will be less than in FY 2025. The Company's engineering, project management, and operations teams discuss and prioritize the work in the program based on the frequency of cable faults, amount of impacted customers and other factors.

Prepared by or under the supervision of: Nicole Gooding

Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-316-7429

Rhode Island Energy™
a PPL company

December 2, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 4 (Complete Set)</u>

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed is the Company's response to Division 4-1 issued in the Division's Fourth Set of Data Requests ("Division Set 4") in the above-referenced matter.

The Company transmitted its response to Division 4-2 on November 27, 2024. This transmittal completes the Company's responses to Division Set 4.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: John Bell, Division
Greg Booth, Division
Al Contente, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.
Al Contente, Division

Division 4-1

Request:

Referring to Section 4, Attachment 1, Page 37, Lines 24 and 29, please provide documentation supporting the Property Tax Expense for End of FY 2023 and End of FY 2024.

Response:

Please see Attachment DIV 4-1 for the requested information.

FY 2023 Property Tax Expense can be found on Attachment DIV 4-1, Page 1, Line 10, Column (p) and FY 2024 Property Tax Expense can be found on Attachment DIV 4-1, Page 2, Line 10, Column (p).

Prepared by or under the supervision of: Jeffrey Oliveira

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			National Grid								PPL					
		Apr-22	May-22	Jun-22			Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Total
(1)	C4081400				Glad	(Multiple Items)										
(2)																
(3)	**Sum of Amount in local currency**	**Column Labels**			**Sum of Monetary Amount**											
(4)		**FY 2023**					**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2023**	**CY 2023**	**CY 2023**	**Grand Total**
(5)	**Row Labels**	**1**	**2**	**3**	**SRC**	**Journal Line Ref**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	
(6)	**TRAN**	**1,406,475.34**	**1,409,110.85**	**1,425,950.79**	**TRAN**		**1,336,195.98**	**726,034.18**	**1,316,703.60**	**1,307,889.39**	**1,314,337.88**	**1,368,303.88**	**1,323,073.11**	**1,332,848.48**	**1,333,054.47**	**15,599,977.95**
(7)		1,407,290.79	1,410,046.58	1,426,841.58	**7505**								1,335,393.00	1,335,393.00	1,335,393.00	8,250,357.95
(8)	5220SC4315M01				**7512**									(2,628,089.79)	0.00	(2,628,089.79)
(9)	5360SC4315M01	(815.45)	(935.73)	(890.79)	**7512**	C4081400	1,336,195.98	726,034.18	1,316,703.60	1,307,889.39	1,314,337.88	1,368,303.88	(12,319.89)	2,625,545.27	(2,338.53)	9,977,709.79
(10)	**ELEC**	**2,796,285.87**	**2,812,849.95**	**2,815,808.23**	**ELEC**		**2,946,078.84**	**2,980,491.37**	**2,885,521.54**	**2,873,501.47**	**2,865,780.93**	**2,903,957.32**	**2,877,961.59**	**2,886,873.49**	**2,887,058.58**	**34,532,169.18**
(11)		2,797,011.70	2,813,689.82	2,816,607.72	**7503**								2,889,181.00	2,889,181.00	2,889,181.00	17,094,852.24
(12)	5220SC4315M01				**7511**									(5,732,169.20)	0.00	(5,732,169.20)
(13)	5360SC4315M01	(725.83)	(839.87)	(799.49)	**7511**	C4081400	2,946,078.84	2,980,491.37	2,885,521.54	2,873,501.47	2,865,780.93	2,903,957.32	(11,219.41)	5,729,861.69	(2,122.42)	23,169,486.14
(14)	**GAS**	**2,709,101.62**	**2,716,514.05**	**2,959,909.47**	**GAS**		**4,824,694.77**	**3,166,915.89**	**3,067,305.51**	**3,081,956.00**	**3,067,316.72**	**3,283,377.71**	**3,136,780.49**	**3,141,611.21**	**3,141,711.54**	**38,297,194.98**
(15)		2,709,495.06	2,716,969.30	2,960,342.84	**7504**								3,142,862.00	3,142,862.00	3,142,862.00	17,815,393.20
(16)	5220SC4315M01				**7513**									(6,170,933.42)	0.00	(6,170,933.42)
(17)	5360SC4315M01	(393.44)	(455.25)	(433.37)	**7513**	C4081400	4,824,694.77	3,166,915.89	3,067,305.51	3,081,956.00	3,067,316.72	3,283,377.71	(6,081.51)	6,169,682.63	(1,150.46)	26,652,735.20
(18)	**Grand Total**	**6,911,862.83**	**6,938,474.85**	**7,201,668.49**	**Grand Total**		**9,106,969.59**	**6,873,441.44**	**7,269,530.65**	**7,263,346.86**	**7,247,435.53**	**7,555,638.91**	**7,337,815.19**	**7,361,333.18**	**7,361,824.59**	**88,429,342.11**

from the Company's General Ledger

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
				Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Total
(1)	Report Filter:															
(2)	(Year = 2023, 2024) And ({Accounting Period} = 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12) And ({Business Unit} = 75100, 75200, 75300, 75400) And (Account (ID) Like "40811")															
(3)																
(4)	**Sum of Monetary Amount**															
(5)				**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2024**	**CY 2024**	**CY 2024**	**Grand Total**
(6)	**SRC**	**Journal Line Ref**	**JE#**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	
(7)	**TRAN**			**1,333,612.47**	**1,333,612.47**	**1,333,612.47**	**1,333,606.78**	**1,337,690.29**	**2,246,555.12**	**1,436,633.00**	**1,436,633.00**	**1,453,530.33**	**1,761,313.00**	**1,761,313.00**	**1,761,313.00**	**18,529,424.93**
(8)	**7505**		JES307	1,335,393.00	1,335,393.00	1,335,393.00	1,335,393.00	1,335,393.00	2,246,555.12	1,436,633.00	1,436,633.00	1,453,530.33	1,761,313.00	1,761,313.00	1,761,313.00	18,534,255.45
(9)	**7512**	C4081400	NEC100	(1,780.53)	(1,780.53)	(1,780.53)	(1,786.22)	2,297.29								(4,830.52)
(10)	**ELEC**			**2,886,746.65**	**2,886,746.60**	**2,886,746.65**	**2,886,762.03**	**2,891,628.20**	**4,860,520.52**	**3,108,219.00**	**3,108,219.00**	**3,144,776.61**	**3,810,677.00**	**3,810,677.00**	**3,810,677.00**	**40,092,396.26**
(11)	**7503**		JES307	2,889,181.00	2,889,181.00	2,889,181.00	2,889,181.00	2,889,181.00	4,860,520.52	3,108,219.00	3,108,219.00	3,144,776.61	3,810,677.00	3,810,677.00	3,810,677.00	40,099,671.13
(12)	**7511**	C4081400	NEC100	(2,434.35)	(2,434.40)	(2,434.35)	(2,418.97)	2,447.20								(7,274.87)
(13)	**GAS**			**3,141,560.09**	**3,141,560.07**	**3,141,560.09**	**3,141,568.32**	**3,144,153.66**	**5,224,979.15**	**3,374,208.00**	**3,374,208.00**	**2,976,275.13**	**3,867,276.00**	**3,867,276.00**	**3,867,276.00**	**42,261,900.51**
(14)	**7504**		JES307	3,142,862.00	3,142,862.00	3,142,862.00	3,142,862.00	3,142,862.00	5,224,979.15	3,374,208.00	3,374,208.00	2,976,275.13	3,867,276.00	3,867,276.00	3,867,276.00	42,265,808.28
(15)	**7513**	C4081400	NEC100	(1,301.91)	(1,301.93)	(1,301.91)	(1,293.68)	1,291.66								(3,907.77)
(16)	**Grand Total**			**7,361,919.21**	**7,361,919.14**	**7,361,919.21**	**7,361,937.13**	**7,373,472.15**	**12,332,054.79**	**7,919,060.00**	**7,919,060.00**	**7,574,582.07**	**9,439,266.00**	**9,439,266.00**	**9,439,266.00**	**100,883,721.70**

from the Company's General Ledger

Division 4-2

Request:

Referring to Section 4, Attachment 1, Page 37, Lines 35 and 40, please explain why the Effective Property Tax Rate decreases from the End of FY 2024 to End of FY 2025 and then increases from the End of FY 2025 to End of FY 2026.

Response:

The Effective Property Tax Rate for each "Plan" year filing is based on the Company's last actual property tax rate as of the Plan filing date. This rate is trued-up in the Company's reconciliation filing when the Company reports the actual net plant amounts and actual property tax expense. The Effective Property Tax rate for FY 2025 is an estimate based on the Company's FY 2023 Effective Tax rate, and The Effective Property Tax rate for FY 2026 is an estimate based on the Company's FY 2024 Effective Tax rate. Both of these rates are estimates and will be trued-up in the Company's reconciliation filings.

Prepared by or under the supervision of: Jeffrey Oliveira

Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com;

280 Melrose Street
Providence, RI 02907
Phone 401-316-7429

Rhode Island Energy™
a PPL company

December 13, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed FY 2026 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Division Data Requests – Set 5 (Complete Set)</u>

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's complete set of responses to the Division's Fifth Set of Data Requests ("Division Set 5") in the above-referenced matter. This transmittal contains the Company's responses to the remaining data requests in Division Set 5.

Please note that Attachments DIV 5-2-1 and DIV 5-2-3 contain critical electric infrastructure information (CEII). The confidential versions will be sent via a secured link and are subject to the universal Non-Disclosure Agreement between the Company and the Division.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure
cc: John Bell, Division
Greg Booth, Division
Al Contente, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.

Division 5-1

Request:

Provide the Company's IEEE quartile results for SAIDI, SAIFI and CAIDI from 2013-2023. Separately provide results for the Northeast region and nationally.

Response:

IEEE Power & Energy Society ("PES") Distribution Reliability Benchmarking National Results are summarized as follows:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	National IEEE SAIFI Quartile											
1	Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	Quartile	1st	1st	2nd	2nd	1st	2nd	2nd	2nd	2nd	1st	1st

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	National IEEE SAIDI Quartile											
1	Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	National IEEE CAIDI Quartile											
1	Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st

The Northeast Investor-Owned Utility IEEE SAIFI Benchmarking Results are summarized as follows:

	(a)	(b)	(c)
	Regional IEEE SAIFI Quartile		
1	Year	2021	2022
2	Quartile	3rd	4th

Northeast Benchmarking Results prior to 2021 were not available currently. The Company has requested 2023 results and will update this request once received.

Prepared by or under the supervision of: Ryan Constable

Division 5-2[1]

Request:

Regarding Weaver Hill Road Substation, the FY25 Q2 report indicates that potential locations on the site are limited, engineering is delayed, and substation and distribution line projects are forecasted to be less than budgeted. The Company also states that ongoing communication is occurring.

a) The Company previously discussed discovering archeological artifacts on the site but believed that the substation could be built on another portion of the site. In the FY25 Q1 report, the Company stated that an additional survey will be completed by the end of the summer to identify potential substation locations. Please provide a more detailed explanation of the site limitations and options being pursued by the Company. Provide all site evaluations, analysis and reports performed to date including the referenced additional survey.

b) Discuss the ongoing communications including the parties or agencies involved.

c) What are the Company's plans if the original site cannot be utilized? Is additional property acquisition required? What is the timeline to secure and permit an alternative location? How does the location impact the remaining project?

d) Provide a list of major equipment purchases for Weaver Hill Substation, including: date initiated, payments made (dates), payments due (dates), and expected delivery dates. Where will the equipment be delivered if the site is not prepared?

e) Is the Company continuing to extend the 3309 and 3310 sub transmission lines, installed for DG customers, to the proposed Weaver Hill substation site that is unpermitted? What is the scope, cost, status and timeline of that portion of the project and where is the work included in the 5-year investment plan?

f) Discuss remaining distribution work (new feeder) planned for the Weaver Hill project, including scope, cost, status and timeline. Indicate where the work is included in the 5-year investment plan.

g) The Company expended $593,000 in FY 2024 and is forecasted to spend $1.1 million in FY 2025 on the Weaver Hill Substation which has delayed engineering. Provide a breakdown of the costs incurred and forecasted through the end of FY 2025. Discuss why the Company is incurring significant costs while the project is delayed.

[1] The Company's response begins on page 2.

Division 5-2, page 2

Response:

a) As required by the State of Rhode Island Historical Preservation and Heritage Commission ("RIHPHC"), the Company performed an archeological survey for the property prior to ground disturbance. Public Archeological Laboratories ("PAL") performed the archeological survey at the Weaver Hill site in the fall of 2023 and identified archeological artifacts in the proposed substation location. Please see Attachment DIV 5-2-1 for the initial report.

   The Company has taken the following steps:

   - An additional archeological survey at the new proposed Weaver Hill Substation site was completed by PAL on October 9, 2024[h] and October 10, 2024. Please see Attachment DIV 5-2-2 for the survey locations proposed on the property.

   - PAL's survey report determined: "No cultural materials were recovered from any of the test pits excavated within the proposed alternative substation footprint.

   - PAL submitted the field work summary report to the RIHPHC on October 24, 2024 for review. Please see Attachment DIV 5-2-3 for the report that was submitted. RIHPHC responded on November 20, 2024 stating that, "…no additional archaeological survey is warranted and that the project will have no effect on any significant cultural resources." Please see Attachment DIV 5-2-4 for the letter from RIHPHC.

b) The Company has been communicating with RIHPHC on the archeological portion of the project as well as the Tribal Historic Preservation officers and the Coventry Zoning Board to inform them of the ongoing work at the site. The Coventry Zoning Board has final approval for the use of this land. The approval process with the Zoning Board takes approximately 6-12 months for review and a final decision.

c) The Company has identified a location on Pine Hill Road in Coventry as a backup site, if needed. The Company would need to complete additional analysis to determine the property rights and permits required, as well as timelines, if this site is needed. This new location would have an impact on cost, schedule and the electric distribution configuration.

d) The Company has not ordered major equipment for this project. The Company defines major equipment as items individually forecasted to be $50,000 or more in spend. The only piece of major equipment is a 34.5/13.2kV 7.5/9.375 MVA, DETC, delta-Wye transformer. The transformer will be ordered by March 2025. The remaining materials will be ordered around August 2025, which is the anticipated date of the Zoning Board decision.

e) Yes, the Company is still planning on doing this work. The 3309 and 3310 scope consists of extending underground 34.5 kV cable approximately 17,000 feet from its existing overhead location to the three DG projects. The DG developers will construct the required manhole and duct system.[2] The Company's total capital estimate for this portion of the project is $5.3 million.

f) The distribution line scope consists of the installation of 2.5 new miles of 477 AL spacer cable from the substation location to Victory Highway. The existing 54F1 and 63F6 circuits will be offloaded onto the new Weaver Hill feeder, with load and distributed generation balanced between the three circuits. This project also will install sectionalizing devices and advanced capacitor banks to maintain reliability and system performance after area reconfigurations. The Company estimates this portion of the project to require $3.9 million of capital spend and will begin construction in FY 2027.

g) Per the Q2 Report, the Company decreased its forecast for the Weaver Hill project to $759,000 for the distribution line, sub-transmission line and substation portion of the project. The Company has since reduced its forecast to $524,000 due to the permitting delays.

A breakdown of these costs is below:

	Actuals and Forecast
Contractors and Consultants	$340,000
Payroll	$77,000
Overheads	$107,000
Total	**$524,000**

[2] As a result of the amount of distributed generation on the 3309 line and the amount of additional generation that would be transferred to Weaver Hill modular feeder, the 3309 could not be used to serve the Weaver Hill substation. Instead the 3311 line will be extended to the Weaver Hill substation.

Attachment DIV 5-2-1

Attachment DIV 5-2-1 contains critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Daniel Glenning

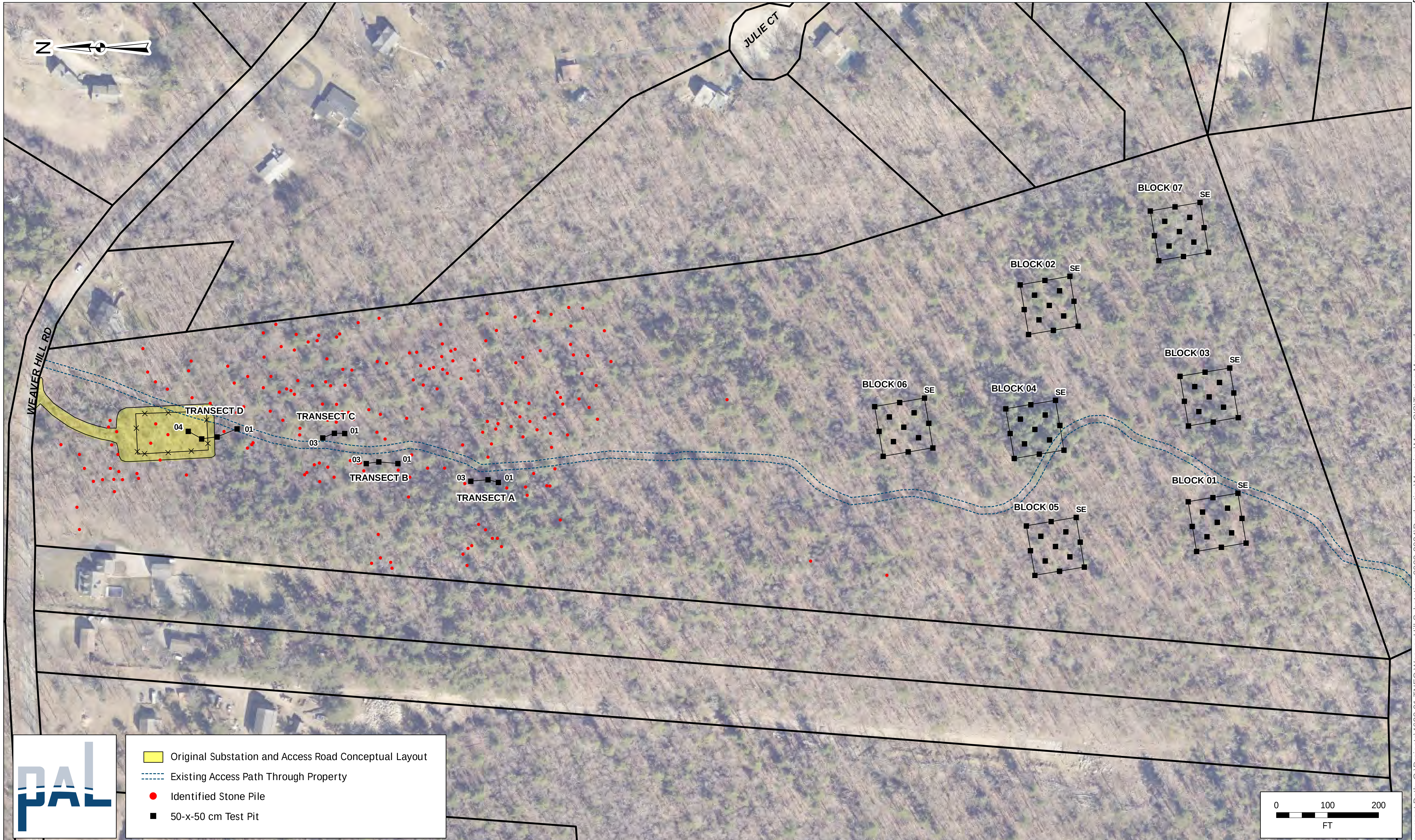


Figure X. Subsurface testing, Weaver Hill Substation.

Attachment DIV 5-2-3

Attachment DIV 5-2-3 contains critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Daniel Glenning

STATE OF RHODE ISLAND

HISTORICAL PRESERVATION & HERITAGE COMMISSION

Old State House 150 Benefit Street Providence, RI 02903

Telephone 401-222-2678 Fax 401-222-2968
TTY 401-222-3700 www.preservation.ri.gov

November 20, 2024

Gregory R. Dubell, RPA
Senior Project Manager
PAL In
26 Main Street, Pawtucket RI 02860

RE: Supplemental Phase I Site Identification
Narragansett Electric--Weaver Hill Substation
West Greenwich, RI

Dear Mr. Dubell:

The Rhode Island Historical Preservation and Heritage Commission (RIHPHC) staff has reviewed the results of the above-referenced survey.

In as much as no cultural resources were located, we concur that no additional archaeological survey is warranted and that the project will have no effect on any significant cultural resources (those listed in, or eligible for listing in, the National Register of Historic Places).

These comments are provided in accordance with Section 106 of the National Historic Preservation Act and the RI Antiquities Act. If you have any questions, please contact RIHPHC Archaeologist Charlotte Taylor at charlotte.taylor@preservation.ri.gov.

Sincerely,

Charlotte Taylor (for)

Jeffrey Emidy
Executive Director
State Historic Preservation Officer

241121.01

Division 5-3

Request:

The Weaver Hill project was recommended by the Company in the Central Rhode Island West Area Study to address the Hopkins Hill 63F6 feeder that was forecasted to be overloaded in 2035 and the Coventry 54F1 feeder that indicated high loading by 2035. The Company's response to Division 2-5 in Docket 23-38-EL indicates that Coventry 54F1 feeder is not projected to exceed 100% by 2035 and Hopkins Hill 63F6 was projected to exceed 100% loading for one hour each year starting in 2024.

a) What were the 54F1 and 63F6 peak loads and percent loading in summer 2024? Provide the date, time and duration of the peak loading.

b) Were there service interruptions on either feeder during the peak? If so, explain if interruptions were loading related or other (vegetation management, etc.)

Response:

a) The actual peak loading for the 54F1 was 377 Amps in 2024 (72% of summer normal rating). This peak occurred on August 3, 2024 between 5:00 PM and 6:00 PM. This peak loading level occurred for roughly 30 minutes.

   The actual peak loading for the 63F6 was 414 Amps in 2024 (78% of summer normal rating). This peak occurred on August 3, 2024 between 3:00 PM and 4:00 PM. This peak loading level occurred for roughly 30 minutes.

   The Company's annual forecast is not yet complete, and the weather adjustment for 2024 actual values is unknown at this time. The appropriate comparison would be weather adjusted values to the Company's forecast.

b) No, there were no load related or other types of service interruptions on either feeder during the peak; however, when performing distribution system planning, the Company manages the electric distribution system to ensure continued safe and reliable operations. Specifically, for the 63F6 feeder, the Company switched load away from the 63F6 temporarily in a previous year to prevent the expected overloads and resulting outages from occurring.

Prepared by or under the supervision of: Ryan Constable

Division 5-4

Request:

What is the inflationary increase applied when deriving non-discretionary budgets? What is the basis for the inflationary factor?

Response:

The inflationary increase applied when deriving non-discretionary budgets was 3%. The basis for the use of the 3% rate was the Bureau of Labor Statistics Consumer Price Index – June 2024 report dated July 11, 2024. Additionally, the Company referred to the University of Michigan Surveys of Consumers YCharts, which provided a U.S. Expected Change in Inflation Rate for the next five years of 2.9%. Please note that applying an inflation rate to prior year spending is only one part of the development of budgets. The Company reviews actual work performed to identify one-time items and unusual and/or non-reoccurring work.

Prepared by or under the supervision of: Nicole Gooding

Division 5-5

Request:

The Company's response to Division 1-9 states that "Field teams are installing transformers available, making safe substitutions as required." Please expand on this statement by explaining examples of substitutions as required. Is the Company installing higher capacity transformers than required to meet load because the transformers are in inventory?

Response:

Yes, the Company was installing higher capacity transformers than required to meet load when the appropriate transformers were not in inventory. This primarily occurred on customer or damage/failure projects. Some examples of the substitutions included using 50kVA transformers in place of a 25kVA transformer and using a 500/750kVA, 3-phase pad mount transformer in place of a 150/300kVA pad mount transformer.

The Company is no longer performing these substitutions as inventory levels have increased for most transformer types.

Division 5-6

Request:

Regarding the Company's response to Division 1-36, the historical exposure for East Bay Area Study feeders totaled 166 MWh and unserved load totals did not exceed 16 MW (results of summing all feeders). The Company's 2025 projections indicate exposure of 284 MWh and unserved load of 41.2 MW.

a) Please explain how the Company derives future projections and why the levels are significantly higher than actual loads. Discuss the specific factors contributing to the 2025 projections that indicate MWh exposure that is 70% greater than 2024 and unserved load that is 190% greater than 2024 (based on totals). Include feeder capacities compared to 2024 actual and 2025 projected loads to support the discussion.

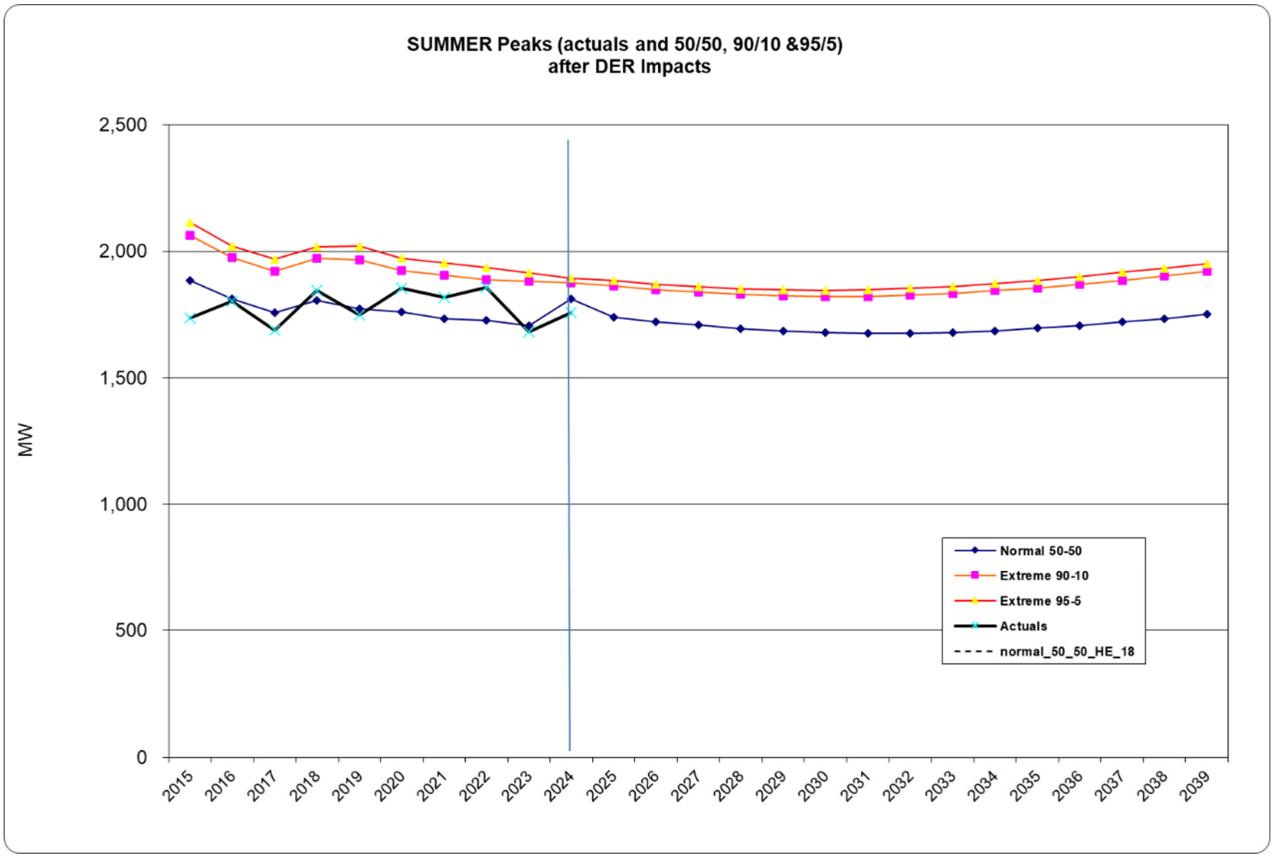
b) The 2015 East Bay Study calculations (Table 4.1.2) indicated that 16 of 19 area feeders were projected to exceed the Company's 16 MWh load-at-risk threshold. Calculations based on actual loads indicate two feeders exceeded the criteria in 2015 and one feeder in 2024, but 10 feeders are projected to exceed the criteria in 2025. If the load has not materialized as originally projected, explain why the Company's forecast has not been adjusted.

c) How often are forecasts updated?

Response:

a) The projected loads are obtained from the Company's forecasts. The Company uses an extreme weather scenario for load forecasts as has been done for the past twenty years and as is common throughout the industry. For example, the ISO-NE uses what is termed a 90/10 extreme weather scenario in planning. For planning analysis, the correct comparison to actuals is whether the actuals are less than the forecasted levels. If actual values are less than forecasted values, then the planning process is sufficient. If actual values exceed the forecasted values, then the planning process would need to be reevaluated. To be cost effective, the extreme weather scenario should be marginally greater than the actual values. This is demonstrated by the following chart where the orange extreme 95-5 line can be seen marginally higher than several of the actual historic loads.

Division 5-6, page 2



<u>Division 5-6, page 3</u>

The Division's calculations for 2025 MWh exposure 70% greater than 2024 and unserved load that is 190% greater than 2024 by summing the columns is not an appropriate representation of the change. For 2024, the combined load growth and weather adjustment factor is approximately 9.3% for the East Bay Area. The 9.3% weather adjustment is the change between actual values and the weather scenario resulting in values appropriate for system planning. The MWh exposure calculation for each feeder considers the neighboring feeder's tie capacity. The values shown in table DIV 1-36 for 2025 are higher than the 2024 actuals because applying the weather adjustment not only increases the subject feeder loading but also reduces the tie's capacity of each tie feeder.

The following example demonstrates the values, where Feeders 2 and 3 tie to Feeder 1.

	Feeder 1 Load	**Feeder 2 Load**	**Feeder 2 Tie Capacity**	**Feeder 3 Load**	**Feeder 3 Tie Capacity**	**Load-at-Risk**
Actual Values	10	10	2	10	3	5
Weather Adjusted Values (10%)	11	11	1	11	2	8

In this simple example, three feeders with 10 megawatts of actual load have a 10% weather adjustment. The load-at-risk between the actual values and the weather adjusted values increase from 5 to 8 or 160%. This 160% is not a meaningful number to distribution system planning. The meaningful number is the 10% weather adjustment.

b) As explained in a previous response the Company uses an extreme weather scenario for appropriate system planning. As can be seen in the figure above, the Company's forecast is adjusted for actual loads. This is also apparent from the reduction of 16 feeders with load-at-risk above guidelines to 10 feeders with load-at-risk above guidelines.

c) Forecasts are updated on a yearly basis.

Division 5-7

Request:

Regarding the Company's response to Division 1-40, once the Phillipsdale Substation Project is completed, will projected overloads and MWh exposure, if any, at both Phillipsdale and Wampanoag be resolved? The answer should assume that East Providence and Warren Expansion projects have not been implemented.

Response:

The East Bay Study recommendation plan was designed to be implemented as a complete solution to address projected overloads, load-at-risk, and asset condition issues. It was not intended to be executed in isolated parts. Without the construction of the East Providence Substation, the projected overloads and the load-at-risk on the Wampanoag feeders will remain unresolved. However, the construction of the Phillipsdale Substation alone would resolve the projected load-at-risk for the Phillipsdale feeders only, by providing additional feeder ties for switching during contingencies.

It is important to note that without the East Providence Substation, the Waterman Avenue Substation and portions of the 23kV system, including the circuit originating in Massachusetts at the Mink Street Substation, would need to remain operational. Additionally, while the Waterman Avenue Substation is geographically located to tie into the Wampanoag and Phillipsdale Feeders, its continued operation would result in virtually no feeder ties between these two systems because the Waterman Avenue feeders are out-of-phase with the rest of the system, which limits their availability for switching under normal operating conditions.

Division 5-8

Request:

Please review and revise as necessary the Company's response to Division 1-43.b., which indicates that some substation work will be complete before the major equipment is delivered (e.g. Phillipsdale D-Sub completion 9-1-26 but transformer and metalclad switchgear expected arrival 9-30-27 per response to Division 1-38).

Response:

After review, the Company determined that the date provided in Division 1-43b was the completion date from the Area Study and was outdated. Due to material lead times of major equipment and the need to complete the East Providence substation prior to final energization of the Phillipsdale substation, the construction completion date shifted from September 2026 to June 2028. This is in alignment with the material delivery dates provided in the Company's response to Division 1-38.

Prepared by or under the supervision of: Daniel Glenning

Division 5-9

Request:

For each active substation project, meaning any substation project which has at least received concurrence from the Division and Commission ISR Plan dollar approval for engineering, list:

a) the month/year the engineering was completed or will be completed,

b) each piece of equipment which has been or will be purchased or ordered, and

c) the month/year the order was or will be placed.

Response:

a) through c)

Please see Attachment DIV 5-9 for the requested information. Please note, the Company included both Separately Tracked Major projects and substation projects under the soft budget cap.

The Company defines major equipment as items individually forecasted to be $50,000 or more in spend.

Date Orders to be Placed (Column d) are estimated based on preliminary design and lead times as the supply chain market is in December 2024; however, these are estimated and subject to change as designs progress, portfolio priorities shift, and equipment lead times change.

Prepared by or under the supervision of: Daniel Glenning

	(a) Project Name	(b) Engineering Complete Date (or to be completed)	(c) Type of Equipment Ordered	(d) Date Order Placed (or to be placed)
1	Gate II Equipment Replacement	September 30, 2027	Transformer	March 31, 2027
2	Ph 1B-Prov Study Admiral St-Rochamb D-SUB	March 31, 2022	No Major Equipment Identified	N/A
3	Ph 4-Prov Study Knightsville 4KV D-SUB	December 31, 2024	Transformer	January 25, 2023
4	Tiverton Sub (D-Sub)	March 31, 2026	No Major Equipment Identified	March 31, 2027
5	Div St#61 T1 T2 Replacement CRIW (was C085405)	June 30, 2026	Transformer	March 31, 2025
6	Anthony #64 Equipment Replacement CRIW (wasC088006)	June 30, 2026	Transformer	March 31, 2025
7	Natick #29 Equipment Replacement CRIW (was C088007)	March 31, 2026	No Major Equipment Identified	N/A
8	Warwick Mall #28 Equipment Replacem CRIW (was C088008)	June 30, 2026	Transformer	March 31, 2025
9	Coventry #54 Sub Relocation CRIW	June 30, 2026	Transformer	March 31, 2025
10	Hope #15 Equipment Replacement CRIW (was C088047)	March 31, 2026	Transformer	March 31, 2025
11	Dexter #36 Equipment Replacement	March 31, 2026	No Major Equipment Identified	N/A
12	Centredale #50 Sub (D-Sub) was C087783	June 30, 2026	Transformer	March 31, 2025
13	Weaver Hill Rd DSub	December 31, 2025	Transformer	March 31, 2025
14	Bristol D Line & D Sub	June 30, 2025	No Major Equipment Identified	N/A
15	ProvStudy New Admiral St 12kV D-Sub	September 30, 2025	Substation Transformer	March 14, 2022
			Metalclad Switchgear	May 13, 2024
			Capacitor Banks	December 17, 2023
16	Apponaug Substation D Sub	June 30, 2026	Transformer	March 31, 2025
17	Phillipsdale D Sub	September 30, 2026	Transformer	March 31, 2025
			Metalclad Switchgear	September 30, 2025
			Capacitor Bank	September 30, 2025
18	Hospital #146 Equipment Replacement	June 30, 2026	Transformer	June 30, 2025
			Metalclad Switchgear	March 31, 2026
19	Kingston #131 Equipment Replacement	June 30, 2026	Transformer	April 30, 2025
			Metalclad Switchgear	September 30, 2025
			Capacitor Bank	March 31, 2026
20	East Providence Substation D Sub	June 30, 2025	Transformer	September 12, 2023
			Metalclad Switchgear	June 24, 2024
			Capacitor Bank	December 16, 2023
21	Nasonville #127 Sub D Sub	September 30, 2024	Transformer	August 23, 2023
			Capacitor Bank	October 2, 2024
22	Chase Hill Second Half of Station	March 31, 2027	Transformer	March 31, 2027
23	New Lafayette 115/12KV D Sub	March 31, 2025	Transformer	November 5, 2021
			Relay Panel Package	June 21, 2024
			Capacitor Bank	December 28, 2023
24	Warren Sub Expansion D Sub	March 31, 2025	Capacitor Bank	December 28, 2023