nationalgrid

Andrew S. Marcaccio
Senior Counsel

February 14, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5209 - Proposed FY 2023 Electric Infrastructure, Safety, and Reliability Plan
Responses to Data Requests - Division Set 5

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed please find the electronic version of the Company's response to the Division's Fifth Set of Data Requests, containing one request, in the above-reference matter.[1]

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7263.

Sincerely,

Andrew S. Marcaccio

Enclosure

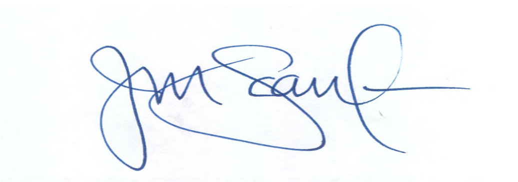
cc: Docket 5209 Service List
Jon Hagopian, Esq.
John Bell, Division
Greg Booth, Division
Linda Kushner, Division

[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

Certificate of Service

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

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



____ February 14, 2022

Joanne M. Scanlon Date

Docket No. 5209 - National Grid's Electric ISR Plan FY 2023
Service List as of 01/10/2022

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Division 5-1

Request:

For each Area Study, provide a list of proposed projects required to solve contingency load-at-risk. For each project, provide the following:

a) Description of contingency issue and load unserved.
b) Number of customers associated with the unserved load, by class.
c) Recommended solution with scope and estimated cost
d) Alternatives identified with scope and estimated cost.
e) Timing of need, indicating projects currently scheduled in the ISR Plan.
f) Discussion of any additional issues resolved by the recommended solution or if the solution is designed exclusively to solve the contingency load-at-risk.

Response:

1. Providence Area Study:

The infrastructure development in the Providence Long Term Area Study is driven primarily by asset condition. The comprehensive plan will address the asset condition issues through the expansion of the 12.47 kV distribution system and conversion of a majority of the 11.5 kV and 4 kV distribution feeders.

After completion of the infrastructure development to address the asset concerns, several feeders have contingency load-at-risk greater than 16 MWHr criteria in 2030, the end of the study period. Non-wires alternatives were evaluated as alternatives at these locations; however, the costs were not found to be economic when compared to traditional wires solutions. Non-wires alternatives will be reevaluated when the area is restudied. However, there are no wires projects in the ISR proposed as solutions since the contingency load-at-risk is not expected until 2030.

2. East Bay Area Study:

a) Numerous feeders in the East Bay study exceed the 16MWhr threshold described in the Distribution Planning criteria. See table from the East Bay Area study report below for details.

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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.

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b) The approximate customers associated with the unserved load for each feeder are shown in the table below.

Station	Feeder	Total Industrial Customers at Risk	Total Residential Customers at Risk
Barrington 4	4F1	111	1078
Barrington 4	4F2	69	835
Bristol 51	51F1	43	418
Bristol 51	51F2	149	1342
Bristol 51	51F3	124	480
Wampanoag 48	48F1	226	1534
Wampanoag 48	48F2	128	155
Wampanoag 48	48F3	103	905
Wampanoag 48	48F4	236	1697
Wampanoag 48	48F5	53	779
Wampanoag 48	48F6	214	982
Warren 5	5F1	55	825
Warren 5	5F2	186	1318
Warren 5	5F3	144	1098
Warren 5	5F4	30	314
Phillipsdale 20	20F1	105	506

c) The recommended plan for this study area addresses all the contingency issues as well as all asset condition issues that were identified in the study in a comprehensive manner. The recommended solution is to:
- Expand Warren 115/12.47kV substation by adding two new distribution feeders
- Construct a new 115/12.47kV substation on First Street in East Providence.
- Replace the out-of-phase 23/12.47kV substation at Phillipsdale with a new 115/12.47kV station
- Install a new feeder, 51F4, at Bristol substation.
- Upgrade the thermal capability of the existing Warren 5F2 and 5F4 feeders.
- Retire Barrington, Waterman, Kent Corners, and Phillipsdale 23/12.47kV substations
- Retire 11 miles of 23 kV subtransmission circuits

Prepared by or under the supervision of: Caitlin Broderick and Ryan Constable

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The estimated cost for this solution is as follows:

Project	CapEx ($M)	OpEx ($M)	Removal ($M)	Total ($M)
Barrington Sub Retirement (D-Sub)	$ -	$ 0.0	$ 0.4	$ 0.5
Bristol D-Line	$ 0.2	$ 0.0	$ 0.0	$ 0.3
Bristol D-Sub	$ 0.6	$ 0.1	$ 0.0	$ 0.7
East Providence Substation (D-Line)	$ 9.1	$ 0.3	$ 1.4	$ 10.8
East Providence Substation (D-Sub)	$ 6.5	$ 0.5	$ 0.1	$ 7.0
Kent Corners Retirement (D-Sub)	$ -	$ 0.0	$ 0.4	$ 0.5
Phillipsdale D-line	$ 2.0	$ 0.1	$ 0.2	$ 2.3
Phillipsdale D-Sub	$ 14.4	$ 0.2	$ 0.6	$ 15.2
Warren Substation Expansion (D-Line)	$ 5.5	$ 0.2	$ 0.8	$ 6.5
Warren Substation Expansion (D-Sub)	$ 4.0	$ 0.1	$ 0.1	$ 4.2
Waterman Ave Retirement (D-Sub)	$ 0.0	$ 0.0	$ 0.4	$ 0.5
Total	$ 42.3	$ 1.7	$ 4.3	$ 48.3

d) Two alternatives were considered to the recommended plan.
Alternative 1 - This plan includes adding new distribution capacity supplied from an upgraded 23kV sub-transmission system, has limited investment in expansion of the 115kV transmission system, and addresses many of the asset conditions with direct replacement. The following are the major modifications proposed:
- Install two new 23/12.47kV Feeders at Phillipsdale substation and address the existing asset condition issues.
- Install two new 23/12.47kV Feeders at Rumford substation
- Install two new 23/12.47kV Feeders at Kent Corners substation
- Build a new 115/23kV substation at Mink Street (Massachusetts Substation)
- Address asset concerns at Barrington substation
- Address asset concerns at Warren substation
- Upgrade and reinforce 7.5 miles of doubled circuited 23kV sub-transmission system
- Retire Waterman substation

The estimated cost of this alternative is shown in the table below. These estimates were developed at the time of the study and are no longer at the same grade as the cost of the recommended plan which has progressed through project development.

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Investment Description ($M)	Capex	Opex	Removal	Total
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Phillipsdale Substation (T-Sub)	$9.000	$0.600	$0.080	$9.680
Phillipsdale Substation (D-Sub)	$3.550	$0.400	$0.350	$4.300
Phillipsdale Substation (D-Line)	$2.250	$0.050	$0.160	$2.460
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.200	$0.800	$2.600	$13.600
Rumford Substation (D-Sub)	$3.600	$0.360	$0.000	$3.960
Rumford Substation (D-Line)	$1.450	$0.050	$0.400	$1.900
Warren Substation (D-Sub)	$2.835	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.000
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 2 (T-Spend)	$13.000	$0.620	$0.300	$13.920
Plan 2 (D-Spend)	$29.285	$2.570	$4.225	$36.080
Total Spend	$42.285	$3.190	$4.525	$50.000

Alternative 2 - This plan is a hybrid between the recommended plan and the alternative above. This plan includes a 115/12.47 kV substation at Phillipsdale. The following are the major modifications proposed:

- Construct a new 115/12.47kV station at Phillipsdale.
- Install two new 23/12.47kV Feeders at Kent Corners substation
- Build a new 115/23kV substation at Mink Street (Massachusetts Substation)
- Address asset concerns at Barrington substation
- Address asset concerns at Warren substation
- Upgrade and reinforce 7.5 miles of doubled circuited 23kV sub-transmission system
- Retire Waterman substation

The estimated cost of this alternative is shown in the table below. These estimates were developed at the time of the study and are no longer at the same grade as the cost of the recommended plan which has progressed through project development.

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Investment Description ($M)	Capex	Opex	Removal	Total
Phillipsdale Substation (T-Line)	$0.400	$0.000	$0.000	$0.400
Phillipsdale Substation (T-Sub)	$0.300	$0.000	$0.000	$0.300
Phillipsdale Substation (D-Line)	$4.430	$0.120	$0.545	$5.095
Phillipsdale Substation (D-Sub)	$6.020	$0.600	$0.380	$7.000
Kent Corners Substation (D-Sub)	$3.600	$0.400	$0.350	$4.350
Kent Corners Substation (D-Line)	$10.300	$0.800	$2.600	$13.700
Mink St Substation (T-Line)	$0.500	$0.000	$0.000	$0.500
Mink St Substation (T-Sub)	$3.500	$0.020	$0.220	$3.740
Mink St Substation (D-Line)	$0.600	$0.000	$0.000	$0.600
Warren Substation (D-Sub)	$2.840	$0.300	$0.025	$3.160
Barrington Substation (D-Sub)	$1.800	$0.180	$0.020	$2.005
Waterman Sub (D-Sub)	$0.000	$0.030	$0.320	$0.350
Plan 1 (T-Spend)	$4.700	$0.020	$0.220	$4.940
Plan 1 (D-Spend)	$29.590	$2.430	$4.240	$36.260
Total Spend	$34.290	$2.450	$4.460	$41.200

e) All contingency load-at-risk issues in the East Bay study were first identified when the East Bay area study was completed in 2015. These projects are currently in the FY23 ISR plan and projected to be in service by FY27 with the exception of Phillipsdale which is projected to be in service in FY28.

f) In addition to addressing contingency load-at-risk issues, the East Providence (First Street) substation, Warren substation, and Phillipsdale substation projects address significant substation and sub-transmission line asset condition issues in the area. The proposed Bristol 51F4 circuit is the only project driven solely by contingency load-at-risk issues as described within the study document.

The Company has no beneficial electrification opportunity criteria at this time, but these projects will increase hosting capacity in the area as well as improve the area's ability to serve additional load anticipated from beneficial electrification.

3. **Central Rhode Island East Area Study:**
There are no contingency load-at-risk projects recommended in this study area.

4. **South County East Area Study:**

a) Numerous feeders in the South County East area study exceed the 16MWh threshold and one transformer exceeds the 240MWh threshold described in the Distribution Planning criteria. See tables below for details.

Substation	Feeder	MWHr	Unserved Load (MW)
Bonnet	42F1	28.4	4.99
Lafayette	30F2	19.5	2.59
Wakefield	17F1	34.6	7.7
Wakefield	17F2	24.1	3
Tower Hill	88F5	20.5	3.88

Substation	Transformer	MWHr	Unserved Load (MW)
Tower Hill	1TR	495	19

b) The approximate customers associated with the unserved load for each feeder and transformer are shown in the table below.

Substation	Feeder	Total Industrial Customers at Risk	Total Residential Customers at Risk
Bonnet	42F1	85	1218
Lafayette	30F2	43	446
Wakefield	17F1	185	1914
Wakefield	17F2	81	717
Tower Hill	88F5	76	907

Transformer	Total Industrial Customers at Risk	Total Residential Customers at Risk
Tower Hill 1TR	576	4146

c) **Bonnet 42F1 -** The recommended solution is to increase the tie capacity of the Wakefield 17F3 feeder by establishing a new feeder tie with the Peacedale 59F4 and transferring load from the 17F3 to the 59F4. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$0.570	$0.000	$0.130	$0.700

Wakefield 17F1 and 17F2 - The first part of the recommended solution for the 17F1 is common to the 42F1 solution. In addition, a project will be needed to create a feeder tie between the Kenyon 68F5 and the Peacedale 59F3 circuits. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$1.740	$0.030	$0.380	$2.150

Lafayette 30F2, Tower Hill 88F5 and Tower Hill Transformer 1TR – The comprehensive area study recommendation to re-build the existing Lafayette Substation to a 115/12.47kV substation and adding two new distribution circuits will solve all of these issues. The two existing, and two new distribution feeders will be routed to relieve heavily loaded distribution feeders and address the MWHr violations. Cost estimates for this plan from the South County East area study report are in the table below.

TABLE 5.3 - Estimated Investments and Expenses for Plan 1

Investment Description ($M)	Capex	Opex	Removal	Total
Lafayette Substation (T-Line)	$1.250	$0.030	$0.070	$1.350
Lafayette Substation (T-Sub)	$1.370	$0.000	$0.000	$1.370
Lafayette Substation (D-Sub)	$8.780	$0.000	$0.000	$8.780
Lafayette Substation (D-Line)	$2.800	$0.100	$0.320	$3.220
3312 ROW Removals (T-Line)	$0.000	$0.000	$2.173	$2.173
84T3 ROW Removals (D-Line)	$0.000	$0.000	$2.633	$2.633
Plan 1 (T-Spend)	$2.620	$0.030	$2.243	$4.893
Plan 1 (D-Spend)	$11.580	$0.100	$2.953	$14.633
Total PLAN 1 Spend	$14.200	$0.130	$5.196	$19.526

d) The 42F1, 17F2 and 17F2 contingency load-at-risk issues were evaluated for Non-Wires Alternatives (NWA). As described in the Company's response to DIV 1-6, the NWAs did not progress as no viable bids were received.

Lafayette 30F2, Tower Hill 88F5 and Tower Hill Transformer 1TR – Alternatives to the New Lafayette Rebuild Plan are below:

Alternative 2 - The major component of this plan is to build a new 115/12.47 kV substation in Quonset on a green field site The proposed substation would consist of a single 115/12.47 kV 24/32/40 MVA LTC transformer and three feeders. This plan would also refurbish 8.6 miles and 8.7 miles of the 84T3 and 3312 34.5kV supply lines, respectively. The estimated cost of this alternative is shown in the table below.

Investment Description ($M)	Capex	Opex	Removal	Total
Mainsail Substation (T-Line)	$2.030	$0.040	$0.130	$2.200
Mainsail Substation (T-Sub)	$1.950			$1.950
Mainsail Substation (D-Sub)	$10.100			$10.100
Mainsail Substation (D-Line)	$4.410	$0.020	$0.120	$4.550
3312 Line Refurbishment (T-Line)	$7.350	$0.200	$0.550	$8.100
84T3 Line Refurbishment (D-Line)	$9.300		$0.400	$9.700
Plan 2 (T-Spend)	$11.330	$0.240	$0.680	$12.250
Plan 2 (D-Spend)	$23.810	$0.020	$0.520	$24.350
Total PLAN 2 Spend	**$35.140**	**$0.260**	**$1.200**	**$36.600**

Alternative 3 - The major component of this plan is to expand Old Baptist substation by installing a third bay, two additional feeders, and station capacitor banks. This plan would also refurbish 8.6 miles and 8.7 miles of the 84T3 and 3312 34.5kV supply lines, respectively. The estimated cost of this alternative is shown in the table below.

Investment Description ($M)	Capex	Opex	Removal	Total
Old Baptist Substation (D-Sub)	$4.400	$0.000	$0.100	$4.500
Old Baptist Substation (D-Line)	$3.330	$0.030	$0.040	$3.400
3312 Line Refurbishment (T-Line)	$7.350	$0.200	$0.550	$8.100
84T3 Line Refurbishment (D-Line)	$9.300	$0.000	$0.400	$9.700
Plan 3 (T-Spend)	$7.350	$0.200	$0.550	$8.100
Plan 3 (D-Spend)	$17.030	$0.030	$0.540	$17.600
Total PLAN 3 Spend	**$24.380**	**$0.230**	**$1.090**	**$25.700**

e) All contingency load-at-risk issues in the South County East area study were first identified when the study was completed in 2018. The new Lafayette substation project is currently in the FY23 ISR plan and projected to be in service by FY26. The 42F1, 17F1 and 17F2 project schedules have not been established yet and will be established as a result of the Company's ongoing prioritization effort of recently completed Area Studies that are expected to be available when the FY 2024 ISR Plan is presented to the Division.

f) In addition to addressing contingency load-at-risk issues, the new Lafayette substation project addresses all significant asset condition issues in the study area including eliminating the need to replace over 17 miles of 34.5kV supply lines.

The Company has no beneficial electrification opportunity criteria at this time, but the Lafayette substation project will increase hosting capacity in the area as well as improve the area's ability to serve additional load anticipated from beneficial electrification.

5A & 5B.

Northwest Rhode Island (Blackstone Valley North and North Central RI) Area Study:

a) The Nasonville transformer exceeds the 240MWh threshold described in the Distribution Planning criteria. See table below for details.

Substation	Transformer	MWHr	Unserved Load (MW)
Nasonville	T271	350	13

b) The approximate customers associated with the unserved load for the Nasonville transformer contingency load-at-risk is shown in the table below.

Substation	Transformer	Total Industrial Customers at Risk	Total Residential Customers at Risk
Nasonville	T271	230	2220

c) The recommended solution scope is:

- Install a new, approximately 6 mile 115kV overhead supply line from Woonsocket Substation to Nasonville Substation.

- At Nasonville substation, install a new transformer and 4 position 13kV metalclad bus

The solution cost estimate is:

Options	Component	Capital ($M)	O&M ($M)	Removal ($M)	Sub Total ($M)	Total ($M)
Option 1	Woonsocket Sub (T)	$5.937	$0.000	$0.000	$5.937	$57.377
	T – Line	$32.381	$0.723	$2.226	$35.330	
	Nasonville Sub (T)	$2.640	$0.000	$0.000	$2.640	
	Nasonville Sub (D)	$13.200	$0.000	$0.208	$13.200	
	Nasonville D – Line	$0.268	$0.000	$0.002	$0.270	

d) Three alternatives were developed:

1. Nasonville –Alternative Option 2

This option is similar to the recommended plan but considers a different 13kV station configuration. Install a new, approximately 6-mile 115kV overhead supply line from Woonsocket Substation to Nasonville Substation and rebuild Nasonville Substation

Options	Component	Capital ($M)	O&M ($M)	Removal ($M)	Sub Total ($M)	Total ($M)
Option 2	Woonsocket Sub (T)	$5.937	$0.000	$0.000	$5.937	$66.672
	T – Line	$32.381	$0.723	$2.226	$35.330	
	Nasonville Sub (T)	$5.000	$0.000	$0.000	$5.000	
	Nasonville Sub (D)	$19.927	$0.000	$0.208	$20.135	
	Nasonville D – Line	$0.268	$0.000	$0.002	$0.270	

2. Nasonville –Alternative Option 3

Install a new, approximately 5-mile 115kV overhead supply line from West Farnum Substation to Nasonville Substation and install a new transformer and 4 position 13kV metalclad bus. This option requires replacement of the West Farnum transformers.

Options	Component	Capital ($M)	O&M ($M)	Removal ($M)	Sub Total ($M)	Total ($M)
Option 3	West Farnum Sub (T)	$23.500	$0.000	$0.500	$24.000	$62.724
	T-Line	$20.438	$0.533	$1.643	$22.614	
	Nasonville Sub (T)	$2.640	$0.000	$0.000	$2.640	
	Nasonville Sub (D)	$13.200	$0.000	$0.000	$13.200	
	Nasonville D -Line	$0.268	$0.000	$0.002	$0.270	

3. Nasonville –Alternative Option 4

Install a new, approximately 6.5-mile 34.5kV overhead supply line from new proposed Iron Mine Hill Substation to Nasonville Substation and install a new transformer and 4 position 13kV metalclad bus.

Options	Component	Capital ($M)	O&M ($M)	Removal ($M)	Sub Total ($M)	Total ($M)
Option 4	Iron Mine Hill Sub (T)	$10.662	$0.000	$0.000	$10.662	$56.467
	Iron Mine Hill Sub (D)	$7.721	$0.000	$0.000	$7.721	
	35kV Line	$22.238	$0.733	$1.643	$24.614	
	Nasonville Sub (D)	$13.200	$0.000	$0.000	$13.200	
	Nasonville D – Line	$0.268	$0.000	$0.002	$0.270	

e) The contingency load-at-risk was first identified when the area study was completed in 2020. The project is currently scheduled to begin in FY24 per Attachment 3 in the FY23 ISR and projected to be in service in FY31. As noted in the response to 4e, above, the Company is currently evaluating the scheduling of all recommendations from the recently completed area studies. The project schedule may change as a result of this prioritization effort.

f) The main purpose of the recommended plan is to address the contingency load-at-risk issue.

Although not a driver, this project will improve reliability by adding a second 115kV supply to Nasonville substation and a second transformer. Similarly, the Company has no beneficial electrification opportunity criteria at this time, but this project will increase hosting capacity at Nasonville substation as well as improve the area's ability to serve additional load anticipated from beneficial electrification.

6. <u>South County West Area Study:</u>

a) Three feeders in the South County West area study exceed the 16MWh threshold and one transformer exceeds the 240MWh threshold described in the Distribution Planning criteria. See tables below for details.

Substation	Feeder	MWHr (2020)	Unserved Load (MW) 2020
Kenyon	68F2	21.5	3.9
Langworthy Corner	86F1	27.1	5.7
Westerly 16F3	16F3	16.5	2.6

Substation	Transformer	MWHr (2020)	Unserved Load (MW) 2020
Chase Hill	2TR	254	10

b) The approximate customers associated with the unserved load for each feeder and transformer are shown in the table below.

Substation	Feeder	Total Industrial Customers at Risk	Total Residential Customers at Risk
Kenyon	68F2	69	1315
Langworthy Corner	86F1	91	1203
Westerly 16F3	16F3	100	544

Transformer	Total Industrial Customers at Risk	Total Residential Customers at Risk
Chase Hill 2TR	219	2525

c) **Kenyon 68F2 -** The recommended solution is to construct a line extension on the 68F5 feeder to create a new feeder tie and offload the 68F2 to the 68F5. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$1.329	$0.044	$0.168	$1.541

Langworthy Corner 86F1 & Westerly 16F3 – The recommended solution is to upgrade existing feeder ties and add one new feeder tie with Westerly Substation Feeders. This will increase the Summer Emergency Rating of the 16F1 and create a new feeder tie with the 16F4. The increase in Summer Emergency Capacity on the 16F1 alleviates the contingency concern on the 16F3. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$2.866	$0.000	$0.318	$3.185

Chase Hill 2TR - The recommended solution to address the Chase Hill transformer contingency load-at-risk issue is to add a second Chase Hill 115/12.47kV transformer and associated equipment. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$2.866	$0.000	$0.318	$3.185

d) **Kenyon 68F2 –** The alternative plan includes utilizing the existing spare breaker position at Kenyon Substation and extending a new feeder, the 68F6, roughly 25,000 feet to the 68F2 and 68F3 circuits. This offloads the area and creates a new feeder tie location for both circuits. Cost estimates for this alternative are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$4.840	$0.000	$0.310	$5.150

As stated in the Company's response to RIPUC Docket 5209 DIV 1-6, the Kenyon 68F2 has also been identified as a Non-Wires Alternative (NWA) opportunity and will be evaluated in the NWA process.

Langworthy Corner 86F1 & Westerly 16F3 – The alternative plan includes building a new modular substation with one new feeder position, on a piece of Company property at Dunn's Corner Road. This would offload the 85T1 and 86F1 circuits, and provide a new feeder pie point for the 86F1. Cost estimates for this alternative are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$8.234	$0.000	$0.915	$9.149

Chase Hill 2TR - The alternative solution for the Chase Hill transformer contingency load-at-risk issue is to upgrade existing feeder ties and add one new feeder tie with the Westerly Substation. This requires approximately 3-4 miles of reconductoring. Cost estimates for this alternative are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$4.210	$0.000	$0.410	$4.622

e) The contingency load-at-risk issues in the South County West area study were first identified when the study was completed in 2021. As noted in the response to 4e, above, the Company is currently evaluating the scheduling of all recommendations from the recently completed area studies. The project schedules will be established as a result of this prioritization effort.

f) The Kenyon, Langworthy Corner, Westerly, and Chase Hill projects are all driven solely by contingency load-at-risk issues. Although not a driver, the installation of a second 115/12.47kV transformer at Chase Hill will improve reliability by adding a second transformer to the substation. Similarly, the Company has no beneficial electrification opportunity criteria at this time, but this project will increase hosting capacity at Chase Hill substation as well as improve the area's ability to serve additional load anticipated from beneficial electrification.

7. <u>Central Rhode Island West Area Study:</u>

There are no contingency load-at-risk projects recommended in this study area.

8. **Tiverton Area Study:**

a) All four Tiverton substation feeders exceed the 16MWh threshold described in the Distribution Planning criteria. See tables below for details.

Substation	Feeder	MWh	Feeder Load at Risk in MVA
Tiverton	33F1	26.3	5.8
Tiverton	33F2	25.2	5.6
Tiverton	33F3	27.9	6.2
Tiverton	33F4	25.6	5.9

b) The approximate customers associated with the unserved load for each feeder and transformer are shown in the table below.

Substation	Feeder	Number of Residential Customers Associated w/ Unserved Load	Number of Commercial Customers Associated w/ Unserved Load
Tiverton	33F1	1,390	169
Tiverton	33F2	1,546	132
Tiverton	33F3	1,633	148
Tiverton	33F4	1,962	146

c) The recommended plan to address the contingency load-at-risk issues on all four of the Tiverton substation feeders includes installing a new Tiverton 33F6 circuit.

There are two Distributed Generation (DG) projects currently in design that require the construction of a new 33F6 circuit for interconnection. If the DG project does not proceed, this 33F6 circuit will still be needed to address the area contingency loading concerns, and the same route would be followed as the least-cost solution. However, the new 33F6 will need to be extended past the proposed DG site to address the contingency load-at-risk issue.

Since the DG project is on a different schedule, which is earlier than the Company's recommended plan, the DG developer will be responsible for the costs in the table below to serve their project. Cost sharing will apply to this potion of work once the 33F6 circuit is being used to serve load as per the Standards for Interconnecting Distributed

Generation (RIPUC 2244) Section 5.4 (b). This estimate does not include the civil work that is being performed in coordination with the DG project.

	Distribution Total ($M)	Substation (D) Total ($M)	Total ($M)
CapEx	3.097	1.022	4.119
OpEx	0.000	0.002	0.002
Removal	0.000	0.000	0.000
Total	3.097	1.024	4.121

The estimates for the work required to extend he 33F6 further south to pick up load from the other Tiverton circuits is included in the table below.

Spend	Distribution Total ($M)
CapEx	1.907
OpEx	0.063
Removal	0.211
Total	2.181

d) There were no reasonable alternatives identified to address the MWh violations. The 33F3 and 33F4 extend approximately 10 miles further south than the other feeders and are both heavily loaded so another feeder needs to be brought further south to offload that supply. The closest other substation is Bates Street 115, which is located in Massachusetts and is out of phase with the Tiverton substation.

e) The contingency load-at-risk issues in the Tiverton area study were identified when the study was completed in 2021. As noted in the response to 4e, above, the Company is currently evaluating the scheduling of all recommendations from the recently completed area studies. The project schedule will be established as a result of this prioritization effort.

f) The Tiverton projects are all driven solely by contingency load-at-risk issues. The Company has no beneficial electrification opportunity criteria at this time, but this project will increase hosting capacity in the area as well as improve the area's ability to serve additional load anticipated from beneficial electrification.

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9. Blackstone Valley South Area Study:

a) Two feeders in the Blackstone Valley South area study exceed the 16MWhr threshold described in the Distribution Planning criteria. See table below for details.

Substation	Feeder	MWh	Unserved Load (MW)
Staples	112W44	22.2	4.7
Valley	102W54	16.2	3.2

b) The approximate customers associated with the unserved load for each feeder are shown in the table below.

Substation	Feeder	Total Industrial Customers at Risk	Total Residential Customers at Risk
Staples	112W44	39	1104
Valley	102W54	46	1182

c) **Staples 112W44 –** Construct an approximately 3.500 circuit foot line extension between the 112W43 and the 112W44 feeders. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$0.399	$0.003	$0.005	$0.407

Valley 102W54 – This contingency-load-at-risk issue will be evaluated for a Non-Wires Alternative (NWA). The wires alternative is listed in part (d).

d) **Staples 112W44 –** There was no alternative developed in detail as the recommended plan is a straight forward line extension and is the least cost fit for purpose option. This project was not considered for detailed NWA development due to the low cost of the wires solution.

Valley 102W54 – The wires alternative is to re-route the Valley 102W50 feeder north of Valley substation to create another tie with the 102W54 feeder. Cost estimates for this plan are in the table below.

Capex ($M)	Opex ($M)	Removal ($M)	Total ($M)
$2.175	$0.071	$0.135	$2.381

e) Both contingency load-at-risk issues in the Blackstone Valley South area study were first identified when the study was completed in 2021. As noted in the response to 4e, above, the Company is currently evaluating the scheduling of all recommendations from the recently completed area studies. The project schedules will be established as a result of this prioritization effort.

f) The recommended solution is designed exclusively to address the Blackstone Valley South contingency load-at-risk issues.

10. Newport Area Study:

There are no contingency load-at-risk projects recommended in this study area.