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

Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan

Responses to Division Data Requests – Set 1

Book 2 of 3

December 22, 2022

Docket No. 22-53-EL

Submitted to**:**
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

November 23, 2022

VIA ELECTRONIC MAIL

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

RE: **<u>RIE's Proposed FY2024 Electric Infrastructure, Safety, and Reliability Plan Responses to Division Set 1 (Batch 1)</u>**

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the please find the Company's responses to the Division's First Set of Data Requests in the above-reference matter. This filing includes responses to DIV 1-1; DIV 1-2; DIV 1-3; DIV 1-5; DIV 1-7; DIV 1-8; DIV 1-9; DIV 1-11; DIV 1-12; DIV 1-13; DIV 1-15; DIV 1-16; DIV 1-17; DIV 1-18; DIV 1-19; DIV 1-26; DIV 1-30; DIV 1-31; DIV 1-32; DIV 1-34; DIV 1-38; DIV 1-39; and DIV 1-40.

Executable Excel files are also attached for the following attachments: Attachment DIV 1-1-1; Attachment DIV 1-1-2; Attachment DIV 1-1-3; Attachment DIV 1-1-4; Attachment DIV 1-9; Attachment DIV 1-13; Attachment DIV 1-15; Attachment DIV 1-30; and Attachment DIV 1-32.

The remaining responses will be filed on or before Tuesday, November 29, 2022.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Schultz, Esq., Division
Christy Hetherington, Esq., Division
Paul Roberti, Esq., Division
John Bell, Division
Al Contente, Division
Linda Kushner, Division
Greg Booth, Division

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Rhode Island Energy™
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November 23, 2022

VIA ELECRONIC MAIL & HAND DELIVERY

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

RE: RIE's Proposed FY2024 Electric Infrastructure, Safety, and Reliability Plan
Responses to Division Set 1 (Batch 2)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the please find the Company's responses to the Division's First Set of Data Requests in the above-reference matter. This filing includes responses to DIV 1-4; DIV 1-6; DIV 1-10; DIV 1-14; DIV 1-20; DIV 1-21; DIV 1-22; DIV 1-23; DIV 1-24; DIV 1-25; DIV 1-27; DIV 1-28; DIV 1-29; DIV 1-33; DIV 1-35; DIV 1-36; DIV 1-37 and DIV 1-41.

The Company is also providing .CEV files in response to DIV 1-22. The Company is transmitting these files via separate link because they are too large to transmit by e-mail. Please be advised that in response to DIV 1-20, the Company is seeking confidential treatment of Attachments DIV 1-20-1 through 1-20-6. These attachments will also be transmitted via separate link.

This transmittal completes the Company's responses to the Division's First Set of Data Requests in the above-referenced matter. Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Gregory Schultz, Esq., Division
Christy Hetherington, Esq., Division
Paul Roberti, Esq., Division
Al Contente, Division
John Bell, Division (w/confidential attachments & .CEV files)
Greg Booth, Division (w/confidential attachments & .CEV files)
Linda Kushner, Division (w/confidential attachments & .CEV files)

Division 1-1

Request:

Provide the following data in executable format:

a. Chart 8, page 25
   Capital Spending by Category FY 2012-CY24

b. Attachment 4 - Chart 5
   RI Reliability Performance CY 2012 – CY 2021
   Regulatory Criteria (Excluding Major Event Days)

c. Attachment 4-Chart 6
   RI Reliability Performance CY 2012 – CY 2021
   Regulatory Criteria (Including Major Event Days)

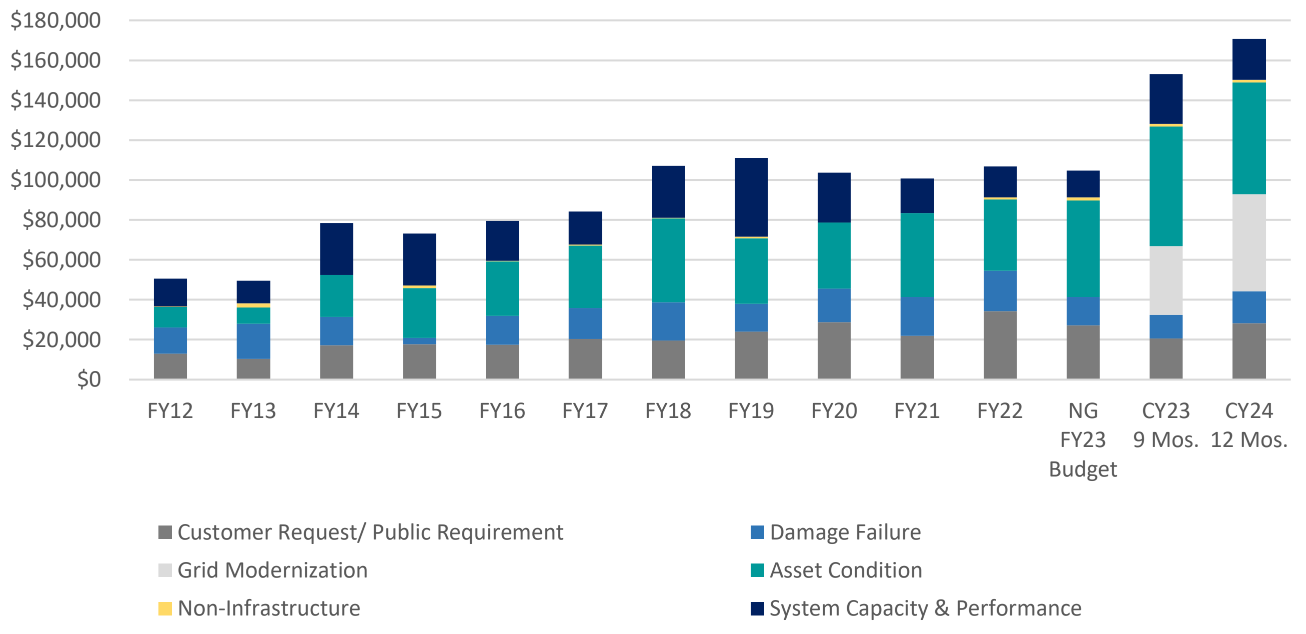
d. Attachment 4-Chart 8
   Rhode Island Customers Interrupted by Cause
   Major Event Days Excluded
   By Calendar Year (2012-2021)

Response:

Please see Attachment DIV 1-1-1 (Chart 8), Attachment DIV 1-1-2 (Attachment 4 - Chart 5), Attachment DIV 1-1-3 (Attachment 4-Chart 6) and Attachment DIV 1-1-4 (Attachment 4-Chart 8) in Excel format.

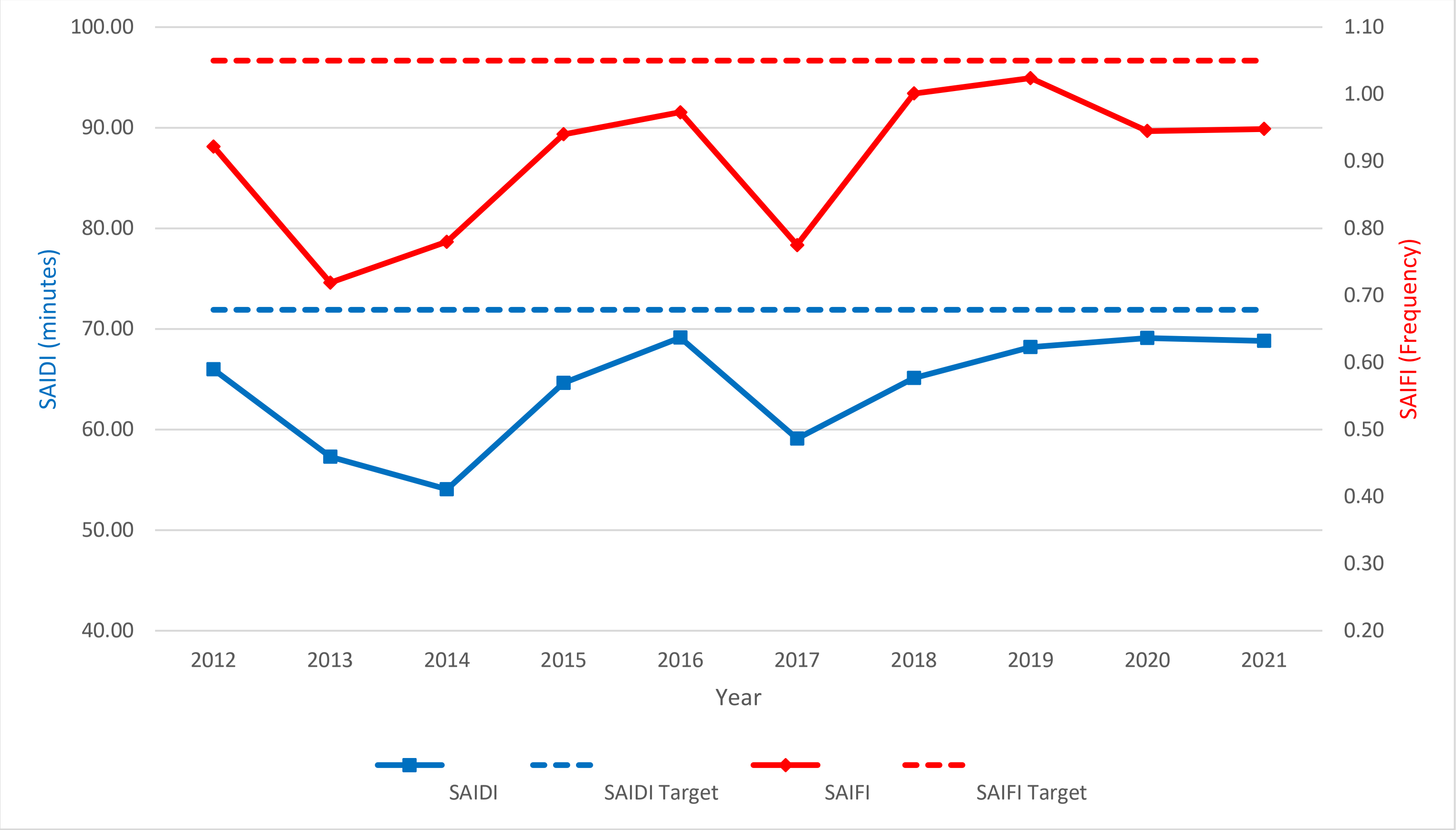
Spending Rationale	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	NG FY23 Budget	CY23 9 Mos.	CY24 12 Mos.
Customer Request/ Public Requirement	$13,075	$10,410	$17,138	$17,760	$17,412	$20,233	$19,627	$23,989	$28,667	$21,990	$34,335	$27,183	$20,683	$28,357
Damage Failure	12,993	17,515	14,374	3,044	14,531	15,614	19,184	13,999	17,028	19,491	$20,200	$14,251	$11,651	15,878
Grid Modernization	0	0	0	0	0	0	0	0	0	0	$0	$0	$34,522	48,586
Asset Condition	10,320	8,071	20,905	25,141	27,179	31,274	41,978	32,897	32,878	41,816	$35,792	$48,289	$59,962	56,152
Non-Infrastructure	149	2,269	(346)	1,216	457	622	363	673	145	(57)	$1,100	$1,520	$1,375	1,289
System Capacity & Performance	13,995	11,249	25,972	25,890	19,920	16,371	25,906	39,515	24,958	17,387	$15,303	$13,508	$24,765	20,455
Total Capital Spending	**$50,532**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$103,676**	**$100,627**	**$106,730**	**$104,750**	**$152,958**	**$170,717**

Chart 8
Capital Spending by Category FY 2012 – CY 2024
($000)



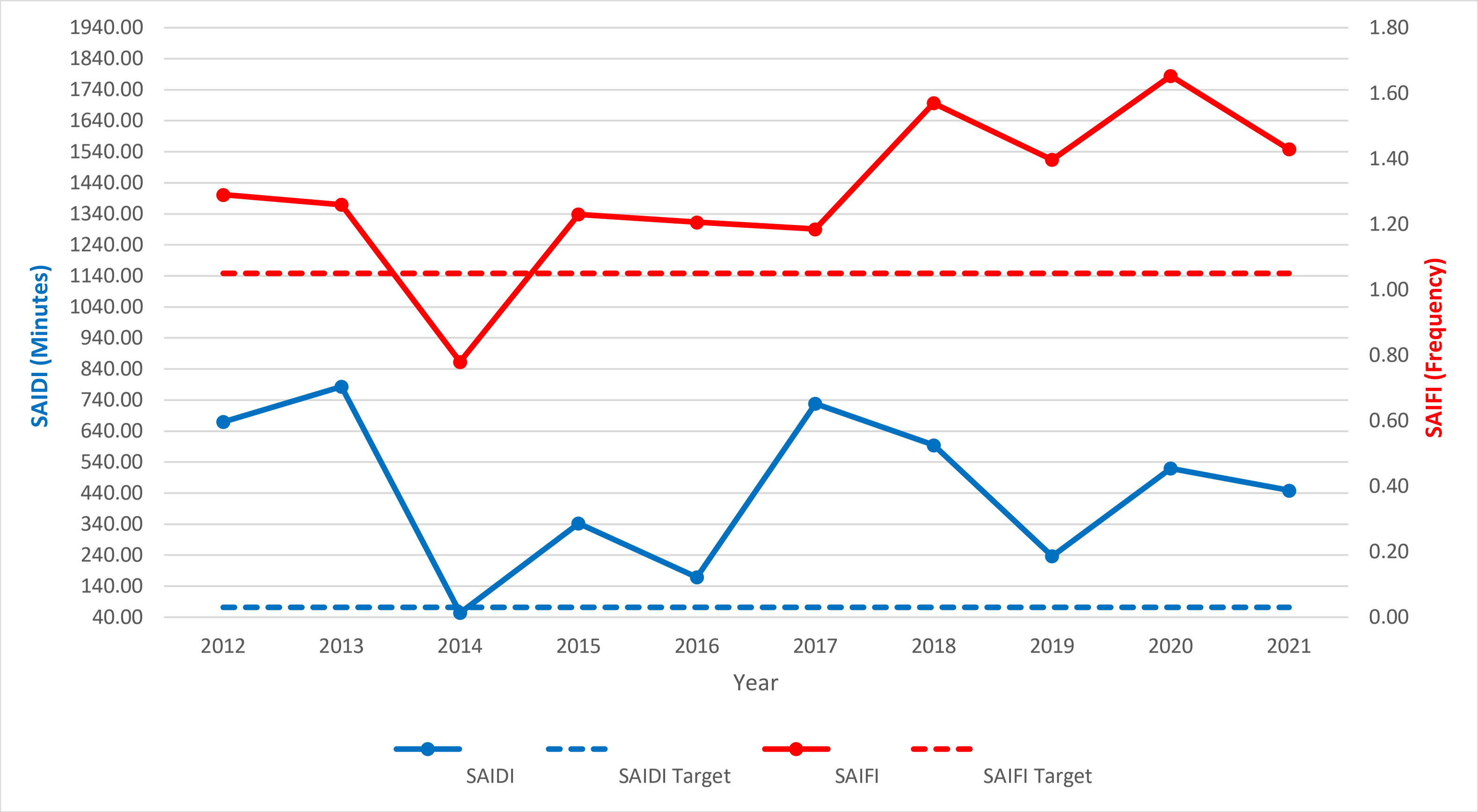
Attachment DIV 1-1-2

Major Storm Excluded				
Year	SAIFI	SAIDI	SAIFI Target	SAIDI Target
2012	0.92	65.99	1.05	71.90
2013	0.72	57.28	1.05	71.90
2014	0.78	54.06	1.05	71.90
2015	0.94	64.63	1.05	71.90
2016	0.97	69.13	1.05	71.90
2017	0.78	59.10	1.05	71.90
2018	1.00	65.11	1.05	71.90
2019	1.02	68.20	1.05	71.90
2020	0.95	69.10	1.05	71.90
2021	0.95	68.80	1.05	71.90



Attachment DIV 1-1-3

Major Storm Included				
Year	SAIFI	SAIDI	SAIFI Target	SAIDI Target
2012	1.29	669.79	1.05	71.9
2013	1.26	783.19	1.05	71.9
2014	0.78	54.06	1.05	71.9
2015	1.23	341.91	1.05	71.9
2016	1.21	168.90	1.05	71.9
2017	1.19	728.34	1.05	71.9
2018	1.57	594.78	1.05	71.9
2019	1.40	236.49	1.05	71.9
2020	1.653	519.85	1.05	71.9
2021	1.429	448.55	1.05	71.9



Major Event Days Excluded

Cause	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	CY21
Adverse Environment	4,778	4,318	3,220	8,677	10,928	8,115	11,964	8,507	17,973	9,212
Animal	9,912	10,324	21,247	29,831	33,541	18,340	21,664	14,277	25,405	28,874
Deteriorated Equipment	47,301	39,131	79,260	77,575	47,966	55,316	65,386	72,114	55,603	72,996
Human Element/ Co.	7,043	13,481	13,259	16,619	5,489	12,995	11,462	11,392	15,066	7,801
Human Element/Other	47,404	54,719	29,908	33,049	43,514	42,510	48,520	52,266	29,164	40,853
Intentional	40,927	55,927	43,132	62,373	68,273	58,544	90,092	80,218	66,301	65,392
Lightning	9,362	23,310	5,745	14,374	10,832	14,505	5,766	12,648	20,127	15,801
Substation	63,397	18,882	30,888	65,932	28,525	6,616	19,802	7,830	32,413	31,896
Sub-Transmission	51,972	48,902	33,556	29,211	33,994	23,710	39,235	35,645	38,474	36,182
Transmission	19,099	5,958	18,284	11,594	72,808	13,786	17,106	40,969	8,856	9,232
Tree	100,459	55,056	70,277	73,248	87,036	95,025	120,812	137,437	140,002	121,540
Unknown	32,176	19,008	19,657	31,703	32,088	30,918	41,014	35,586	21,341	34,354
Grand Total	**433,830**	**349,016**	**368,433**	**454,186**	**474,994**	**380,380**	**492,823**	**508,889**	**470,725**	**474,133**

Division 1-2

Request:

Is RIE requesting Division concurrence on a 9-month or 21-month plan?

Response:

For its Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan, Rhode Island Energy is requesting the Rhode Island Division of Public Utilities and Carriers' ("Division") concurrence on a 21-month capital investment and other spending plan for the period April 1, 2023, through December 31, 2024. As a result of the acquisition of the Company by PPL Rhode Island Holdings, LLC from National Grid USA, which closed on May 25, 2022, the Company's fiscal year changed from the twelve-month period ending March 31 to the twelve-month period ending December 31. As a one-time transition from its prior fiscal year under National Grid USA ownership to its current fiscal year under PPL Rhode Island Holdings, LLC ownership, the Company is seeking the Division's concurrence on a spending plan that covers the remaining nine-month period of calendar year 2023, which are not included in the Company's approved FY 2023 Electric ISR Plan, and the twelve-month period of calendar year 2024.

Prepared by or under the supervision of: Nicole Begnal

Division 1-3

Request:

When will RIE file its subsequent ISR Plan, and what will be the proposed term of the plan?

Response:

Rhode Island Energy will submit the proposed Fiscal Year 2025 Electric ISR Plan to the Division of Public Utilities and Carriers between April 1, 2024, and May 1, 2024. The Company would file with the Public Utilities Commission on or around July 1, 2024, with anticipated approval on or around October 1, 2024. The term of the plan would be the twelve-month period from January 1, 2025, through December 31, 2025.

The Company is open to considering alternatives regarding the timing for its subsequent Electric ISR Plan filing.

Prepared by or under the supervision of: Nicole Begnal

Division 1-4

Request:

How are grid modernization investments, which are 25% of total FY 2024 ISR Plan spend, determined and incorporated in the Work Plan Process (Chart 2, page 8)?

Response:

To determine the grid modernization investments, the Company, in accordance with requirements of the Amended Settlement Agreement approved by the Public Utilities Commission ("PUC") in Docket No. 4770, is engaging with stakeholders through the Power Sector Transformation Advisory Group, to develop a comprehensive Grid Modernization Plan ("GMP"). The Company is conducting a statewide assessment in conjunction with the development of its GMP, which the Company will be filing with the PUC in the near term. The Company will supplement this and related responses as additional information that may impact the proposed Electric ISR spend becomes available through the development of the GMP. That assessment aligns with the inputs, process, and outputs described in the Work Plan Process (Chart 2, page 8). In determining the grid modernization investments to include in the Fiscal Year 2024 Electric ISR Plan spend, the Company used similar methods for forecasting, capacity reviews, and study details, but in many cases expanded analysis techniques to assess the different dynamic nature of future technology of both load and solutions. Like Area Studies, the GMP will identify system issues, complete an alternative assessment, and outline details of required technologies and investments. The GMP also will present a capital plan, but in a different manner from traditional planning efforts. The similarities and differences are further detailed as follows.

Similarities:

- Forecasts - The GMP starts with the same load forecast used by all other planning efforts.
- Capacity Reviews - The GMP uses the same annual capacity reviews that are used to inform other planning efforts.
- Study Process - All 11 Rhode Island areas were studied for the GMP.
- Alternatives - Because the purpose of the GMP is to evaluate whether grid modernization technologies should be pursued, two alternatives were considered: (1) solutions with grid modernization technologies and (2) solutions without grid modernization technologies.

Prepared by or under the supervision of: Ryan Constable

Division 1-4, page 2

Differences:

- Forecasts - The GMP forecast projects beyond the typical 15 years to 2050 to sufficiently analyze system issues that may arise in meeting Rhode Island's Act on Climate requirements.
- Study Process - The GMP analysis method is substantially more complex than typical planning efforts as contemplated by the Capital Work Plan Process (Chart 2, page 8).
- Capital Work Plan – Although the GMP evaluates infrastructure investments under the "with and without grid modernization" options, these infrastructure investments were not compiled into a work plan. This is in recognition of the size and location variations that can occur with actual customer adoption of heating and transportation electrification and distributed generation on the path to achieving the Act on Climate mandates. Rhode Island Energy will be aligning such infrastructure investments with actual customer adoption in future interconnection studies and future area studies. The infrastructure evaluated with the GMP is used to determine an avoided cost benefit of the foundational grid modernization investments.
- The capital plan developed, as aligned with the intent of the GMP, includes the foundational grid modernization investments and field devices to maximize benefits.

To summarize, the grid modernization investments are based on standard planning needs assessment and are aligned with the Work Plan Process (Chart 2, page 8). Rhode Island Energy plans to file the GMP with the PUC in December 2022 demonstrating the urgency of proceeding now with grid modernization investments that are needed to address existing and future system issues and present the least cost and most benefits versus continuing on a non-grid modernization path.

Prepared by or under the supervision of: Ryan Constable

Division 1-5

Request:

The Division has been recommending a 10 year I&M cycle. What evaluation and analysis has the Company given to the longer cycle and did RIE review the National Grid assessments?

Response:

The Company does not have specific analysis showing that 10 years or longer is a more appropriate cycle time. The Company does, however, believe that the revised distribution I&M inspection program is much more targeted and efficient than it was in the past. The Company has decreased its budgeted spend by choosing to field repair only what is categorized as high priority. This allows the Company to continue to monitor the condition of the assets while keeping the repairs targeted.

Prepared by or under the supervision of: Ryan Constable

Division 1-6

Request:

Does RIE agree with past Division recommendations regarding previous ISR Plan reviews, and if not, explain the reasoning?

Response:

The Company has reviewed the past five years of Division recommendations regarding previous Electric ISR Plan reviews. Please see table below for the Company's comments regarding previous reviews and proposed revisions to the Division's recommendations going forward.

Division 1-6, page 2

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2023	1	The Company shall continue to coordinate with the Division to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications. The Company shall put forth program adjustments in the FY 2024 ISR Plan that include advancing Damage/Failure to a "fix on failure" strategy.	The Company adopted the new process of categorizing only work related to failed assets in the Non-discretionary portfolio during FY 2021. All other work is categorized in the Asset Condition category of the Discretionary portfolio. The detailed analysis, review, monitoring and reporting to ensure proper classification continues into FY 2023. Significant improvement in the categorization and documentation of work related to failed asset has been achieved. The Company suggests eliminating this recommendation at the end of CY 2023. The Company will continue to provide the detail for Damage/Failure in Attachment F as well as the Excel file on a quarterly basis as noted in Recommendation 7.	The Company shall continue to coordinate with the Division to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications. The Company shall put forth program adjustments through the end of calendar year 2023 ~~in the FY 2024 ISR Plan~~ that include advancing Damage/Failure to a "fix on failure" strategy.

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

Division 1-6, page 3

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2023	2	The Company shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the System Reliability Procurement ("SRP") plans, Area Studies, ISR Plan, non-wires alternatives ("NWA") options and internal Design Criteria.	The Company agrees with this recommendation and considers it normal course of business.	
2023	3	The Company shall continue enhancing current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline. -Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning ("DSP"), Heat Maps, and emerging initiatives.	The Company agrees with the recommendation with minor clarifications. For the first point, the traditional elements are included in our area studies as applicable. For example, criticality rankings are utilized in our programs not in studies. The Company works to ensure there is no redundancy in area studies and recommendations. The fourth point regarding the evaluation of potential incremental investments will be included in the Grid Modernization Plan, which will be filed in December 2022.	The Company shall continue enhancing current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/~~criticality rankings,~~ alternatives considered, solution, cost and timeline. -Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning ("DSP"), Heat Maps, and emerging initiatives.

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

Division 1-6, page 4

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		-A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning. -An evaluation of potential incremental investments that support the Company's long -term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs. -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits. done within the studies -A correlation of the 11 Area Studies to each other for the development of a holistic system Long-Range Plan which further informs the ISR Plan.	The second to last point related to NWA evaluation has been completed within the individual area studies. For the last point, areas are defined by distinct geographical and electrical boundaries that have minimal overlap. Should the Company determine that multiple areas have common system solutions those areas are combined and studied closely together, for example Blackstone Valley North and North Central RI. An analysis of the overall system in a holistic manner is conducted when the issues impact the entire system. For example, the Company is performing a state-wide review to analyze forecasted system impacts of load and generation in the Grid Modernization analysis. The analysis is informed by the Area Study solutions and in certain scenarios identified Area Study solutions may be revised so that the most optimal plan will be executed.	-A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning. -An evaluation of potential incremental investments that support the Company's long -term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs. done in GMP -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits. done within the studies -A correlation of the 11 Area Studies to each other for the development of a holistic system Long-Range Plan which further informs the ISR Plan.

Division 1-6, page 5

FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2023	4	The Company shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall analyze the overall system in a holistic manner using the now completed 11 Area Studies to establish enhancements in the Area Study solutions. The Company shall use the completed Area Studies to re-prioritize and sequence all solutions and major projects in the Long-Range Plan. The Company shall submit and present the outcome of each revised Area Study to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities, holistic system long range plan development and revision of each Area Study status at least 120 days prior to filing its FY 2024 ISR Plan Proposal, but in any event no later than August 31, 2022.	The Company agrees in principle with the recommendation of to developing a System Capacity Load Study and a 10-year Long Range Plan. The Company takes several factors into consideration when sequencing projects including, need identified in the study, availability of resources, materials, outage constraints and funding.	The Company shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall analyze the overall system in a holistic manner using the now completed 11 Area Studies to establish enhancements in the Area Study solutions. ~~The Company shall use the completed Area Studies to re-prioritize and sequence all solutions and major projects in the Long-Range Plan.~~ The Company shall submit and present the outcome of each revised Area Study to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities, holistic system long range plan development and revision of each Area Study status at least 120 days prior to filing its FY 2024 ISR Plan Proposal, but in any event no later than August 31, 2022.

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

Division 1-6, page 6

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2023	5	The Company shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.	The Company will continue to manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects and report on large projects in Attachment G of the quarterly reports. If, however, a need arises, the Company believes that it should be able to advance a project and be held to a prudency review during the annual reconciliation process.	The Company shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects~~, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall~~ and provide quarterly budget and project management reports.
2023	6	The Company will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.	The Company agrees with this recommendation.	
2023	7	The Company shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.	The Company agrees with this recommendation and will continue to report on Level I projects repaired and Damage/Failure the quarterly reports.	

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

Division 1-6, page 7

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2023	8	The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2024 ISR Plan Proposal filing, and in any event no later than August 31, 2022.	The Company agrees with the recommendation of providing transparency for the future years spend. With the completion of both Area Studies and the Long Range Plan, however, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.	The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided ~~in advance of~~ within the FY 2025 ISR Plan Proposal filing.~~, and in any event no later than August 31, 2022.~~
2023	9	The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan in advance of the FY 2024 ISR Plan Proposal filing, and in any event no later than August 31, 2022.	The Company will continue to provide an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan. With the completion of both Area Studies and the Long Range Plan, however, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.	The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan ~~in advance of~~ within the FY 2025 ISR Plan Proposal filing.~~, and in any event no later than August 31, 2022.~~
2023	10	The Company shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan,	The Company will continue to submit its detailed substation capacity expansion plans and load projections and evaluation of proposed projects against the Company's Long Range Plan. With the completion of	The Company shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, ~~in advance of~~ within the FY 2025 ISR Plan

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		in advance of the FY 2024 ISR Plan Proposal filing, and in any event no later than August 31, 2022.	both Area Studies and the Long Range Plan, however, the Company would like to submit this information in subsequent ISR Plans, instead of in Pre-Filing documentation.	Proposal filing.~~, and in any event no later than August 31, 2022.~~
2023	11	The Company shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review prior to submitting the Company's FY 2024 ISR Plan Proposal, and in any event no later than August 31, 2022.	Rhode Island Energy is in the process of making changes to National Grid's Cycle Clearing Program and the Enhanced Hazard Tree Management Program. The Company is discussing how to best complete a cost-benefit analysis for the new programs and can provide this within the FY 2025 ISR Plan Proposal filing.	The Company shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review ~~in advance of~~ within the FY 2025 ISR Plan Proposal filing.~~, and in any event no later than August 31, 2022.~~
2023	12	In the event the PPL acquisition of Narragansett transpires, Narragansett Electric shall provide within 60 days of closing a comprehensive report addressing, at a minimum: an organizational chart identifying the new ISR Plan team members and responsibilities as compared to the current organization, any changes in the project sanctioning process; any proposed changes to the ISR Plan process; and a schedule for the quarterly presentations of the quarterly reports. The Company	The Company agrees with this recommendation and provided an organizational chart and dates for upcoming ISR Plans and quarterly reports in the Pre-Filing documentation sent to the Division on September 9, 2022. The Company recently completed its sanctioning process and is providing this information to the Division.	

Division 1-6, page 9

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		shall provide report updates at each quarterly presentation.		
2022	1	National Grid shall coordinate with the Division to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications. The Company shall put forth program adjustments in the FY 2023 ISR Plan that include advancing Damage/Failure to a "fix on failure" strategy.	Please see response for FY 2023 Recommendation 1.	
2022	2	National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, NWA options and internal Design Criteria.	Please see response for FY 2023 Recommendation 2.	

Prepared by or under the supervision of: Nicole Begnal and Kathy Castro

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2022	3	National Grid shall continue enhancing current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline. -Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning ("DSP"), Heat Maps, and emerging initiatives. · A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning. -An evaluation of potential incremental investments that support the Company's long - term grid modernization strategy. This includes description of technology or infrastructure investment, cost-	Please see response for FY 2023 Recommendation 3.	

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs. -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.		
2022	4	National Grid shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities and Area Study status at least 120 days prior to filing its FY 2023 ISR Plan Proposal, but in any event no later than August 31, 2021.	Please see response for FY 2023 Recommendation 4.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2022	5	National Grid shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.	Please see response for FY 2023 Recommendation 5.	
2022	6	National Grid will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.	Please see response for FY 2023 Recommendation 6.	
2022	7	National Grid shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.	Please see response for FY 2023 Recommendation 7.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2022	8	National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2023 ISR Plan Proposal filing, and in any event no later than August 31, 2021.	Please see response for FY 2023 Recommendation 8.	
2022	9	National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan in advance of the FY 2023 ISR Plan Proposal filing, and in any event no later than August 31, 2021.	Please see response for FY 2023 Recommendation 9.	
2022	10	National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's LongRange Plan, in advance of the FY 2023 ISR Plan Proposal filing, and in any event no later than August 31, 2021.	Please see response for FY 2023 Recommendation 10.	
2022	11	National Grid shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management	Please see response for FY 2023 Recommendation 11.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
		program for the Division's review prior to submitting the Company's FY 2023 ISR Plan Proposal, and in any event no later than August 31, 2021.		
2021	1	National Grid shall coordinate with the Division to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement blanket programs to validate proper classifications. The Company shall put forth program adjustments in the FY 2022 ISR Plan that include advancing Damage/Failure to a "fix on failure" strategy.	Please see response for FY 2023 Recommendation 1.	
2021	2	National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, NWA options and internal Design Criteria.	Please see response for FY 2023 Recommendation 2.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2021	3	National Grid shall propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline. - Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, DSP, Heat Maps, and emerging initiatives. -A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning. -An evaluation of potential incremental investments	Please see response for FY 2023 Recommendation 3.	

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		that support the Company's long - term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. The GMP should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs. -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.		
2021	4	National Grid shall continue to develop a System Capacity Load Study and a 10-year LongRange Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities and Area Study status at least 120 days prior to filing its		

FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
		FY 2022 ISR Plan Proposal, but in any event no later than August 31, 2020.		
2021	5	National Grid shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.	Please see response for FY 2023 Recommendation 5.	
2021	6	National Grid will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.	Please see response for FY 2023 Recommendation 6.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2021	7	National Grid shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.	Please see response for FY 2023 Recommendation 7.	
2021	8	National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2022 ISR Plan Proposal filing, and in any event no later than August 31, 2020	Please see response for FY 2023 Recommendation 8.	
2021	9	National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long-Range Plan in advance of the FY 2022 ISR Plan Proposal filing, and in any event no later than August 31, 2020.	Please see response for FY 2023 Recommendation 9.	
2021	10	National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long-Range Plan,	Please see response for FY 2023 Recommendation 10.	

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		in advance of the FY 2022 ISR Plan Proposal filing, and in any event no later than August 31, 2020.		
2021	11	National Grid shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review prior to submitting the Company's FY 2022 ISR Plan Proposal, and in any event no later than August 31, 2020.	Please see response for FY 2023 Recommendation 11.	
2020	1	National Grid and the Division shall consider a method to combine and manage a discretionary budget for repairs completed in the Damage/Failure and I&M categories separately from a budget required to replace failed equipment in the non-discretionary category. The Company's proposed FY 2021 ISR Plan should include budget categories, rationale, and proposed spend that reflect a consensus methodology.	Please see response for FY 2023 Recommendation 1.	
2020	2	National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization	Please see response for FY 2023 Recommendation 2.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
		strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, NWA options and internal Design Criteria.		
2020	3	National Grid shall propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline. -Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, DSP, Heat Maps, and emerging initiatives. -A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.	Please see response for FY 2023 Recommendation 3.	

FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		-An evaluation of potential incremental investments that support the Company's long term grid modernization strategy. This includes description of technology or infrastructure investment, cost benefit to traditional safety and reliability objectives, and additional operational benefits achieved if implemented. -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.		
2020	4	National Grid shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities and Area Study status at least 120 days prior to filing its FY 2021 ISR Plan Proposal, but in any event no later than August 31, 2019.	Please see response for FY 2023 Recommendation 4.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2020	5	National Grid shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.	Please see response for FY 2023 Recommendation 5.	
2020	6	National Grid will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.	Please see response for FY 2023 Recommendation 6.	
2020	7	National Grid shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.	Please see response for FY 2023 Recommendation 7.	

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FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
2020	8	National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2021 ISR Plan Proposal filing, but in any event no later than August 31, 2019.	Please see response for FY 2023 Recommendation 8.	
2020	9	National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2020 ISR Plan Proposal filing, but in any event no later than August 31, 2019.	Please see response for FY 2023 Recommendation 9.	
2020	10	National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, in advance of the FY 2021 ISR Plan Proposal filing, but in any event no later than August 31, 2019.	Please see response for FY 2023 Recommendation 10.	
2020	11	National Grid shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management	Please see response for FY 2023 Recommendation 11.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		program for the Division's review prior to submitting the Company's FY 2021 ISR Plan Proposal, but in any event no later than August 31, 2019.		
2020	12	National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost benefit analysis to the Division prior to submitting the Company's FY 2021 ISR Plan Proposal to the extent any Metal-Clad Switchgear replacements or major upgrades are proposed, but in any event no later than August 31, 2019.	The Company agreed with this recommendation and has completed its Metal-Clad Switchgear replacements.	
2019	1	National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, NWA options and internal Design Criteria.	Please see response for FY 2023 Recommendation 2.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2019	2	National Grid shall propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at minimum: -The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline. -Discussion on the impact to related Company initiatives, PUC programs, the various pilot projects, or other requirements driven by SRP, DSP, Heat Maps, and emerging initiatives. - A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning. -An evaluation of potential incremental investments that support the Company's long term grid modernization strategy. This includes description of technology or infrastructure investment, cost benefit	Please see response for FY 2023 Recommendation 3.	

FY	**#**	**Recommendation**	**Comments**	**Rhode Island Energy Proposed Changes**
		to traditional safety and reliability objectives, and additional operational benefits achieved if implemented. -A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.		
2019	3	National Grid shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. These studies shall include a separate Non-Wire Alternative analysis of the projects consistent with the requirements of other program commitments. The Company shall submit a report with updates on modeling activities and Area Study status at least 120 days prior to filing its FY 2020 ISR Plan Proposal, but in any event no later than August 31, 2018.	Please see response for FY 2023 Recommendation 4.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2019	4	National Grid shall manage major Asset Replacement and System Capacity & Performance project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.	Please see response for FY 2023 Recommendation 5.	
2019	5	National Grid will continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes major substation projects.	Please see response for FY 2023 Recommendation 6.	
2019	6	National Grid shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.	Please see response for FY 2023 Recommendation 7.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
2019	7	National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2020 ISR Plan Proposal filing, but in any event no later than August 31, 2018.	Please see response for FY 2023 Recommendation 8.	
2019	8	National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2020 ISR Plan Proposal filing, but in any event no later than August 31, 2018.	Please see response for FY 2023 Recommendation 9.	
2019	9	National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, in advance of the FY 2020 ISR Plan Proposal filing, but in any event no later than August 31, 2018.	Please see response for FY 2023 Recommendation 10.	
2019	10	National Grid shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management	Please see response for FY 2023 Recommendation 11.	

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FY	#	Recommendation	Comments	Rhode Island Energy Proposed Changes
		program for the Division's review prior to submitting the Company's FY 2020 ISR Plan Proposal, but in any event no later than August 31, 2018		
2019	11	National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost benefit analysis to the Division prior to submitting the Company's FY 2020 ISR Plan Proposal to the extent any Metal-Clad Switchgear replacements or major upgrades are proposed, but in any event no later than August 31, 2018.	Please see response for FY 2020 Recommendation 12.	

Division 1-7

Request:

Explain in detail how the 2023/2024 21-month ISR Plan fits the Long Range Plan ("LRP") and specifically the Company's previous LRP meeting explanation of substation elimination and deferrals by Mr. Constable.

Response:

The Company's Long-Range Plan ("LRP") is presented in two five-year steps ranging from calendar year 2023 to calendar year 2032. Step 1 of the plan, which spans between calendar years 2023 to 2027, is inclusive of discretionary and non-discretionary spend within all spending rationale categories: System Capacity and Performance, Asset Condition, Non-Infrastructure, Damage Failure, Customer Request and Public Requirement, and Grid Modernization. Step 2 of the plan spans between calendar years 2028 to 2032. At this time, the Company has only included spend originating from the completed Area Studies and the fundamental investments included in the Grid Modernization Plan. These investments fall within the System Capacity and Performance, Asset Condition, and Grid Modernization spending rationale categories. Other non-discretionary and discretionary categories were not included in Step 2 of the LRP because of the unreliable nature of forecasting spend on projects that are unknown and further out in time.

The proposed Fiscal Year 2024 ISR Plan includes spend from the first 21 months of Step 1 of the LRP. This includes nine months of calendar year 2023 and twelve months of calendar year 2024 (i.e., April 1, 2023 through December 31, 2024). Also, although the Company is not requesting concurrence with calendar years 2025 to 2027, the capital forecasts are provided in the five-year budget overview.

The recent completion of Area Studies has introduced new System Capacity and Performance and Asset Condition projects to the 21-month ISR Plan. The Providence, East Bay, and Central RI East multi-year projects have been in previous ISR Plans and are included in the current ISR Plan. The following is a list of projects from the LRP that the Company added to the ISR Plan:

- Apponaug Long Term Plan (Station Rebuild)
- Centredale Conversion
- Phillipsdale Rebuild (continuation of East Bay area work)
- Bristol Substation New Feeder (continuation of East Bay area work)
- Tiverton Substation Asset Condition and New Feeder Projects
- Central RI West Asset Condition and System Capacity & Performance Projects
- Nasonville Substation Expansion
- Staples Reliability Improvements

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- Weaver Hill New Substation
- Newport Area Loading, Contingency, and Asset Condition Projects
- Northwest RI Loading, Voltage, and Asset Condition Projects
- South County West Loading, Voltage, and Contingency Projects
- Blackstone Valley South Asset Condition Projects (Conversions)
- West Greenville Asset Condition Projects
- Auburn Substation Rebuild (continuation of Providence area work)

Mr. Constable explained in a meeting in early 2022 that the Company based project execution schedules on several factors, including need identified within the study, required sequencing of work, resource needs, and availability of funds. At the time of the meeting, prior to the acquisition of the Company by PPL Rhode Island Holdings, LLC, there were several factors, including resource and cash constraints that required the deferral of projects. Rhode Island Energy has a renewed focus and commitment to address the system issues represented by the projects listed above and, after consideration of the contributing factors described above, it has not identified the need to delay work.

Also at that meeting, Mr. Constable explained that the scope of certain projects might be eliminated or adjusted through the grid modernization analysis. For example, the Merton Station Rebuild included as part of the Newport Asset Condition projects may be converted to 13.8 kV instead of rebuilt at 4 kV. Any adjustments will be described within the Grid Modernization Plan that the Company expects to file with the Public Utilities Commission in late December 2022. Projects originating from Area Studies will reference the Grid Modernization Plan to ensure the Company is advancing the most comprehensive solution.

Division 1-8

Request:

Provide the Company's IEEE quartile results for SAIDI, SAIFI and CAIDI from 2012-2021. Provide for regional utilities (describing the region) and nationally if available.

Response:

IEEE yearly benchmarking quartiles (based on all participating utilities across United States) for SAIFI, SAIDI and CAIDI are summarized in the following table. In the recent years, Rhode Island Energy SAIFI has consistently ranked in the 2nd quartile and while 2021 shows 1st quartile the Company is at the absolute bottom. The Company considers its current average performance as 2nd quartile. Reliability investments, such as the main line recloser program, grid modernization and the CEMI 4 are being proposed in response to this consistent decline in SAIFI performance with the goal of ranking in the top of companies in the 1st quartile.

	CY2012	CY2013	CY2014	CY2015	CY2016	CY2017	CY2018	CY2019	CY2020	CY2021
SAIFI Quartile	1st	1st	1st	2nd	2nd	1st	2nd	2nd	2nd	1st
SAIDI Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st
CAIDI Quartile	1st	1st	1st	1st	1st	1st	1st	1st	1st	1st

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Division 1-9

Request:

Regarding Attachment 4-Chart 3, provide in executable format RIE's CEMI Performance vs EEI Survey for years 2012-2021.

Response:

RIE's CEMI performance vs EEI survey is attached in executable format as an Excel file referenced as Attachment DIV 1-9.

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CEMI	**CY2012**	**CY2013**	**CY2014**	**CY2015**	**CY2016**	**CY2017**	**CY2018**	**CY2019**	**CY2020**	**CY2021**
CEMI3+	17.9%	14.3%	6.7%	14.3%	11.6%	16.0%	22.0%	19.8%	24.7%	20.6%
CEMI4+	7.5%	5.9%	1.3%	4.8%	5.2%	6.2%	11.3%	11.1%	12.9%	10.3%
CEMI5+	3.3%	1.7%	0.3%	1.1%	2.2%	2.5%	5.5%	5.6%	6.7%	5.0%
CEMI6+	**1.4%**	**0.6%**	**0.0%**	**0.2%**	**1.3%**	**1.0%**	**3.5%**	**3.7%**	**3.1%**	**2.5%**

CEMI	**CY2012**	**CY2013**	**CY2014**	**CY2015**	**CY2016**	**CY2017**	**CY2018**	**CY2019**	**CY2020**	**CY2021**
CEMI3+ Quartile	3rd	3rd	1st	3rd	2nd	2nd	3rd	3rd	4th	3rd
CEMI4+ Quartile	3rd	2nd	1st	2nd	2nd	2nd	3rd	3rd	3rd	3rd
CEMI5+ Quartile	3rd	1st	1st	2nd	2nd	2nd	3rd	3rd	3rd	3rd
CEMI6+ Quartile	3rd	1st	1st	1st	3rd	2nd	3rd	3rd	3rd	3rd

EEI 2012 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	<=9.00	10.00-12.60	12.93-18.00	>=19.00
CEMI4+	<=3.90	4.00-5.94	6.00-9.00	>=10.00
CEMI5+	<=1.52	1.60-2.70	2.80-4.38	>=5.00
CEMI6+	<=0.60	0.61-1.10	1.20-2.00	>=2.36

EEI 2013 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	<10.20	10.20-13.67	14.22-19.10	>=20.43
CEMI4+	<3.91	3.91-6.41	6.84-9.70	>=9.72
CEMI5+	<1.80	1.80-2.92	3.07-5.00	>=5.40
CEMI6+	<0.76	0.76-1.35	1.49-3.19	>=3.20

EEI 2014 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	< 11.00	11.00-13.66	13.73-21.05	>=21.10
CEMI4+	<4.68	4.68-6.20	6.70-11.00	>=11.40
CEMI5+	<2.03	2.03-3.10	3.11-5.70	>=5.90
CEMI6+	<1.00	1.00-1.50	1.56-3.00	>=3.52

EEI 2015 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	<9.90	9.90-14.10	14.20-24.50	>=24.70
CEMI4+	<4.29	4.29-5.90	6.10-12.91	>=13.20
CEMI5+	<1.9	1.90-2.70	2.80-7.00	>=7.30
CEMI6+	<0.78	0.78-1.20	1.22-4.00	>=4.29

EEI 2016 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	<11.10	11.10-14.23	14.232 - 20.00	>20
CEMI4+	<5.06	5.06-7.01	7.07-10.00	>10
CEMI5+	<2.07	2.07-3.02	3.05-4.89	>4.89
CEMI6+	<1.00	1.00-1.21	1.29-2.36	>2.36

EEI 2017 Survey With Major storm				
	1st	2nd	3rd	4th
CEMI3+	<9.00	9.00-16.00	16.10-24.78	>24.78
CEMI4+	<3.78	3.78-8.00	8.05-13.01	>13.01
CEMI5+	<1.61	1.61- 4.00	4.15-7.95	>7.95

CEMI6+	**<0.72**	**0.72- 1.80**	**1.81-4.93**	**>4.93**

EEI 2018 Survey With Major storm				
	1st	**2nd**	**3rd**	**4th**
CEMI3+	**<11.14**	**11.14-16.33**	**16.40-25.30**	**>25.30**
CEMI4+	**<4.98**	**4.98-8.00**	**8.46-14.18**	**>14.18**
CEMI5+	**<2.01**	**2.01-4.08**	**4.10-8.12**	**>8.12**
CEMI6+	**<0.86**	**0.86-2.09**	**2.20-5.00**	**>5.00**

EEI 2019 Survey With Major storm				
	1st	**2nd**	**3rd**	**4th**
CEMI3+	**<13.06**	**13.06-18.95**	**19.04-27.47**	**>27.47**
CEMI4+	**<6.20**	**6.20-8.83**	**8.85- 14.08**	**>14.08**
CEMI5+	**<2.91**	**2.91-4.36**	**4.51-8.10**	**>8.10**
CEMI6+	**<1.39**	**1.39-2.33**	**2.36-4.64**	**>4.64**

EEI 2020 Survey With Major storm				
	1st	**2nd**	**3rd**	**4th**
CEMI3+	**< 10.91**	**10.91- 15.98**	**16.06 - 22.77**	**> 22.77**
CEMI4+	**< 4.67**	**4.67- 7.76**	**7.92 - 13.05**	**>13.05**
CEMI5+	**< 1.91**	**1.91 - 4.10**	**4.10 - 7.38**	**> 7.38**
CEMI6+	**< 0.89**	**0.89- 2.065**	**2.15 - 4.20**	**> 4.20**

EEI 2021 Survey With Major storm				
	1st	**2nd**	**3rd**	**4th**
CEMI3+	**<11.74**	**11.74- 18.04**	**18.04 - 24.89**	**>24.89**
CEMI4+	**< 5.51**	**5.51- 9.12**	**9.12 - 13.27**	**>13.27**
CEMI5+	**< 2.39**	**2.39 - 4.83**	**4.83 - 7.6**	**>7.6**
CEMI6+	**< 1.09**	**1.09-2.38**	**2.38 - 4.33**	**>4.33**

Division 1-10

Request:

The Company has discussed that there is an effort to improve reliability given actual reliability metric results and trending in Rhode Island. Explain and support this effort in light of the Company's ability to meet or exceed regulatory reliability targets (Attachment 4-Chart 4). Provide a comparison of forecasted and proposed spend in the FY 2024 ISR Plan spend, by category, against the Company's previously forecasted spend for the same time periods as filed in Docket 5209 (specifically, compare file *ISR FY2024-Attachment 3 (Final to the Division 10-21-22)* to file *FY2023 RI Elec 5 Yr. Budget-Att 3 (PUC 12-20-21)*). Highlight each category and corresponding amount of spend proposed in the FY 2024 ISR Plan that is intended to support RIE's efforts to improve reliability that were not included in the previous ISR Plan. Include GMP investments considered necessary to support this effort, if applicable, and identify those investments and associated costs.

Response:

Rhode Island Energy acknowledges that reliability performance meets targets as shown in Attachment 4-Chart 4; however, there is an upward trend in both SAIDI and SAIFI performance as highlighted by Attachment 4-Charts 1 and 2. Based on IEEE SAIFI benchmarking results, the Company consistently ranked in the second quartile, and, although 2021 shows first quartile performance, the Company is at the bottom. The Company considers its current average performance as second quartile. Based on latest J.D. Power results, overall Customer Satisfaction, which has a direct correlation to reliability, has plunged to fourth quartile. All measures indicate the declining reliability performance of the system and the need for course correction.

Attachment DIV 1-10 shows a comparison between *ISR FY2024-Attachment 3 (Final to the Division 10-21-22)* to file *FY2023 RI Elec 5 Yr. Budget-Att 3 (PUC 12-20-21).* For simplicity, Fiscal Year ("FY") 2024 values of the FY 2023 plan are compared to Calendar Year ("CY") 2024 values of the FY 2024 plan. The following items, included in the System Capacity and Performance section of the plan, are highlighted to support Rhode Island Energy's efforts to improve reliability that were not included in the previous ISR Plan:

- Mainline Recloser Enhancements
- Staples substation Reliability Improvements
- Tiverton Substation

Grid modernization investments are integral to each other and need to be advanced in a coordinated manner to maximize benefits for all customers. The following investments, which

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Division 1-10, page 2

are included in the Grid Modernization section of the plan, are intended to support multiple efforts inclusive of reliability:

- ADMS/DERMS Advanced
- Advanced Reclosers in the Grid Modernization section
- Electromechanical Relay Replacement Program
- Fiber Network
- IT Infrastructure
- Mobile Dispatch

In addition to the investments listed above, the Company is planning to progress a CEMI-4 program to address areas of poor performance. System and Circuit Average Interruption Frequency Indices measure the experience of the average customer; however, using them exclusively can drive planning and investment decisions to parts of the system that have the highest customer densities. This leads to uneven reliability performance across the distribution circuits and unhappy customers. Currently, approximately 12% (60,000) of Rhode Island Energy customers experience four or more interruptions in a rolling twelve-month period, putting Rhode Island Energy in the third quartile of performance. The CEMI Program will identify and fix reliability issues for customers experiencing significantly poorer service than ystem or circuit averages with a goal of first quartile performance within five to ten years. The following is the five-year capital budget that will be proposed in the Company’s final FY 2024 ISR Plan filing:

CEMI 4 Program Cash Flows ($000s)	Cost Type	CY 2023 (9 Months)	CY 2024	CY 2025	CY 2026	CY 2027
	CAPEX	$820	$1,640	$1,640	$1,640	$1,640
	OPEX	$30	$60	$60	$60	$60
	Removal	$35	$65	$65	$65	$65

		FY23 Filing	FY24 Filing
Spending Rationale and Category	**ISR Grouping**	FY24 Values	CY23 Values
System Capacity & Performance - Major Projects	Aquidneck Island	0	1038
	Aquidneck Island - Other Sub Improvements	932	
	Chase Hill - Second Half of Station		0
	Chase Hill Common Items		0
	East Providence Substation	2050	1233
	Jepson Substation	0	
	Mainline Recloser Enhancements		9504
	Nasonville Substation	912	912
	New Lafayette Substation	2275	750
	Staples substation Reliability Improvements		270
	Tiverton Substation		64
	Warren Substation	2310	1969
	Weaver Hill Rd substation	150	1162
System Capacity & Performance - Major Projects Total		8628	16902
System Capacity & Performance - Other	3V0	400	825
	Blanket	2064	1992
	COVID	0	
	EMS/RTU	433	603
	OH Line Transformer Replacements	1500	
	Other		1610
	Other Area Study Projects - Central Rhode Island West		1372
	Other Area Study Projects - East Bay		0
	Other Area Study Projects - Newport		0
	Other Area Study Projects - Northwest Rhode Island		1226
	Other Area Study Projects - South County West		236
	Other Load Relief & Reliability	100	
	Reserve	3298	0
	Storm Hardening	0	
	VVO	0	0
System Capacity & Performance - Other Total		7795	7863
Asset Condition - Major Projects	Apponaug Substation	300	763

	Centredale Substation	1117	1116
	Division St Transformers	1000	
	Dyer St substation	0	0
	Phillipsdale Substation	2390	2390
	ProvStudy Phase 1A	0	0
	ProvStudy Phase 1B	15429	20787
	ProvStudy Phase 2	1674	1674
	ProvStudy Phase 3	0	0
	ProvStudy Phase 4	3157	9605
	South Street Completion	0	
	Tiverton Substation		85
Asset Condition - Major Projects Total		25067	36420
Asset Condition - Other	Batteries	400	230
	Blackstone Valley South 4kV Substation Ret.		0
	Blanket	5228	3915
	Other	0	782
	Other Area Study Projects - Blackstone Valley South		858
	Other Area Study Projects - CRIW - D-Line		390
	Other Area Study Projects - CRIW Equipment Repl		2801
	Other Area Study Projects - East Bay		0
	Other Area Study Projects - Newport		0
	Other Area Study Projects - Northwest Rhode Island		270
	Other Area Study Projects - Providence		0
	Other Area Study Projects - South County West		0
	Recloser Replacement Program	0	
	Reserve	4000	0
	RI.I&M	3000	2256
	RI.UG Cable Replacement	5500	5228
	RI.URD	8000	6280
	Substation Breakers & Reclosers	0	
	UG Improvements	620	465
Asset Condition - Other Total		26748	23476
Asset Condition - SouthEast Substation	New Southeast Sub	0	66
Asset Condition - SouthEast Substation Total		0	66

Non-Infrastructure	Blanket		300
	Corporate/Admin/General	0	
	Other	254	283
	Telecommunications	1085	792
Non-Infrastructure Total		1339	1375
Damage/Failure	Damage/Failure	10794	9171
	Nasonville Substation Rebuild		1092
	Reserves - DF	1205	
	Storms	1950	1388
Damage/Failure Total		13949	11651
Customer Request/Public Requirement	3rd Party Attachments	275	210
	DER - Non-Discretionary	0	
	Distributed Generation	1000	750
	Land and Land Rights	487	375
	Meter Programs	140	
	Meters	2715	1971
	New Business - Commercial	9088	6820
	New Business - Residential	7124	5409
	Outdoor Lighting	568	431
	Public Requirements	1205	937
	Regulatory Requirement		0
	Transformers	4872	3780
Customer Request/Public Requirement Total		27474	20683
Grid Modernization Plan	ADMS/DERMS Advanced		105
	Advanced Reclosers		17405
	DER Monitor/Manage		651
	Electromechanical Relay Repl Pgm		2040
	Fiber Network		8105
	IT Infrastructure		1514
	Mobile Dispatch		74
	Smart Capacitors & Regulators		4629
Grid Modernization Plan Total			34523
Grand Total		111000	152960

Division 1-11

Request:

Please expand Attachment 4-Chart 8 (page 25) to include the number of minutes that customers were interrupted for each interruption cause for CY2017-CY21.

Response:

Referring To Attachment 4 – Chart 8,[1] the following table summarizes customer minutes of interruptions by cause from CY2017 to CY2021:

Cause	CY17	CY18	CY19	CY20	CY21
Adverse Environment	341,769	879,895	307,937	704,283	456,912
Animal	1,093,111	1,125,352	830,296	1,487,469	1,777,528
Deteriorated Eqmt	4,654,948	5,266,850	5,023,359	5,239,394	6,001,946
Human Element/Company	741,172	804,697	429,240	1,688,155	812,365
Human Element/Other	3,718,950	4,026,043	3,251,025	2,189,150	3,036,064
Intentional	2,501,563	2,805,085	3,975,123	3,010,202	2,975,715
Lightning	1,537,330	550,580	1,450,612	1,224,556	1,607,363
Sub-Transmission	1,672,628	2,075,016	753,213	2,571,916	1,251,987
Substation	617,255	463,435	293,839	1,597,252	1,055,057
Transmission	600,634	209,408	1,323,993	297,496	750,175
Tree	9,403,813	11,476,841	13,478,697	12,533,121	11,860,769
Unknown	3,095,630	2,889,374	2,773,492	1,884,039	2,804,336
Grand Total	29,978,803	32,572,576	33,890,826	34,427,033	34,390,217

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[1] Please note Attachment 4 – Chart 8 is found on Bates 71.

Division 1-12

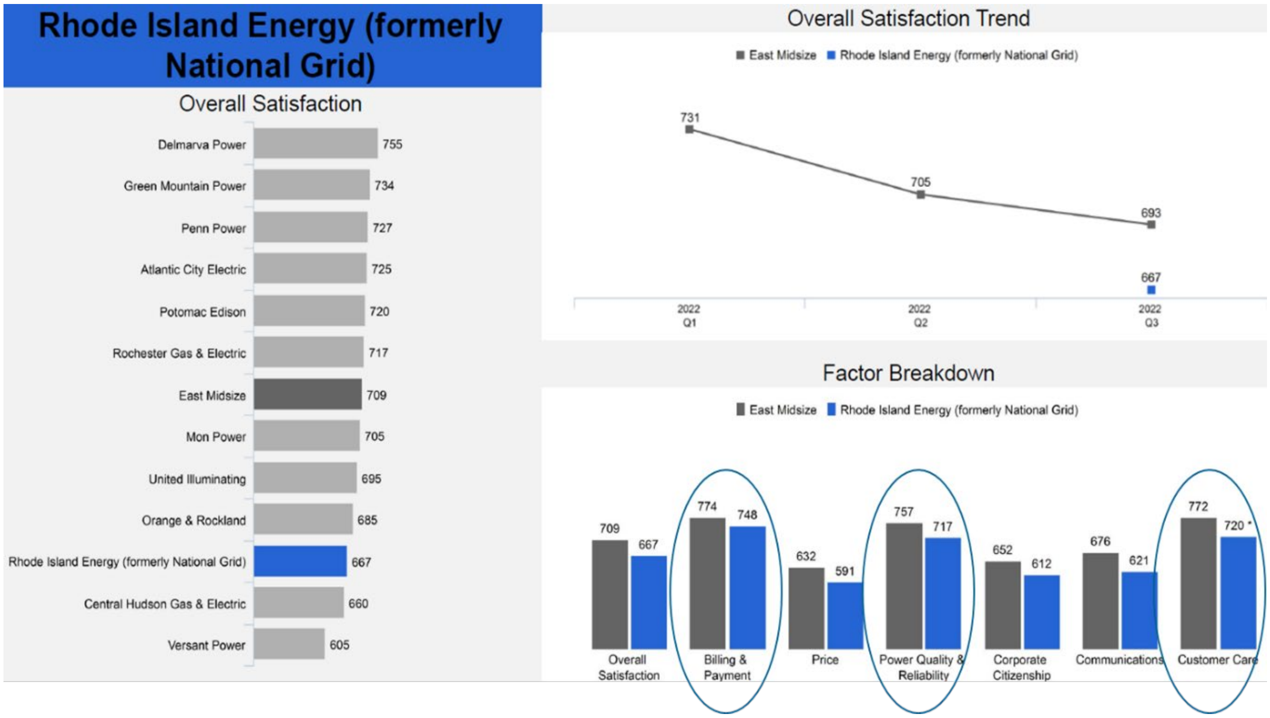
Request:

Provide all data, reports, surveys or assessments that indicate Rhode Island utility customer satisfaction with electric utility reliability, including results of J.D. Power Electric Utility Business Customer Satisfaction Study.

Response:

J.D. Power 2022 3rd quarter results for Rhode Island Energy indicate residential customers overall satisfaction trended lower for the third consecutive quarter. The 667 (out of 1000) score is lower than the mean of 709 and ranks in the 4th quartile when compared to other midsize eastern utilities.

J.D. Power Quality and Reliability score was 717 (out of 1000), lower than the mean score of 757 and ranked in the 4th quartile. Below is the summary from the report.



Division 1-13

Request:

Provide an updated 3V0 chart in executable format, specifically identifying projects in the FY 2024 ISR Plan (see FY 2023 Attachment DIV 1-14).

Response:

An updated 3V0 chart is included below along with an excel file as Attachment DIV 1-13.

Substation	**Project Estimate**		**CY2023 Forecast (9M) 04/01/23 - 12/31/23**		**CY2024 Forecast(12 M) 01/01/24 -12/31/24**		**3V0 Targeted Completion Date**	**3V0 Actual Completion Date**
	Capex	**Opex**	**Capex**	**Opex**	**Capex**	**Opex**		
Peacedale	$427,500	$22,500	$14,600	$0	$0	$0	03/31/22	Projected 03/08/23
Clark St	$540,000	$60,000	$405,000	$45,000	$135,000	$15,000	03/31/24	TBD
Natick	$540,000	$60,000	$405,000	$45,000	$135,000	$15,000	03/31/24	TBD
FY 2025 3V0 D-SUB	$0	$0	$0	$0	$675,000	$75,000	TBD	TBD
TOTAL FORECAST FY23-FY24			$824,600	$90,000	$945,000	$105,000		

Division 1-14

Request:

What RIE or PPL departments are responsible for performing load forecasts and capacity reviews? Has RIE incorporated any load forecasting changes under PPL ownership? Explain and provide a copy of the latest detailed load forecast.

Response:

The load forecasts are being developed as a collaborative effort between the PPL Load Analytics & ISO Settlement group and the National Grid Load Forecasting group. There have been no changes to the load forecasting process under PPL ownership. The latest detailed forecast is the NARRAGANSETT ELECTRIC COMPANY 2022 Electric Peak (MW) Forecast, dated November 2021 and is included as Attachment DIV 1-14. This forecast is also available through the RI Data Portal (https://ngrid.apps.nationalgrid.com/NGSysDataPortal/RI/index.html). Capacity reviews are completed by Rhode Island Energy's Distribution Planning & Asset Management group. There are no changes to this process.

Prepared by or under the supervision of: Ryan Constable

NARRAGANSETT ELECTRIC COMPANY

2022 Electric Peak (MW) Forecast

15-Year Long-Term

2022 to 2036

November 2021

Original, Nov/12/2021

Economics and Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/12/2020	- ORIGINAL

General Notes:

- Hourly load data through August 2021; projections from 2021 winter forward.
- Economic data is from Moody's vintage August 2021.
- Energy Efficiency, electric heating, solar, energy storage and demand response is internal data vintage August 2021.
- Electric Vehicle data is POLK data vintage May 2021. Medium- and heavy- duty electric vehicles and E-buses have been added this year.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (Jan. 2003 to Jun. 2021), internal unreconciled **preliminary** data (Jul. 2021 to Aug. 2021).
- Peak load data is metered zonal load; but without ISO bulk system losses.

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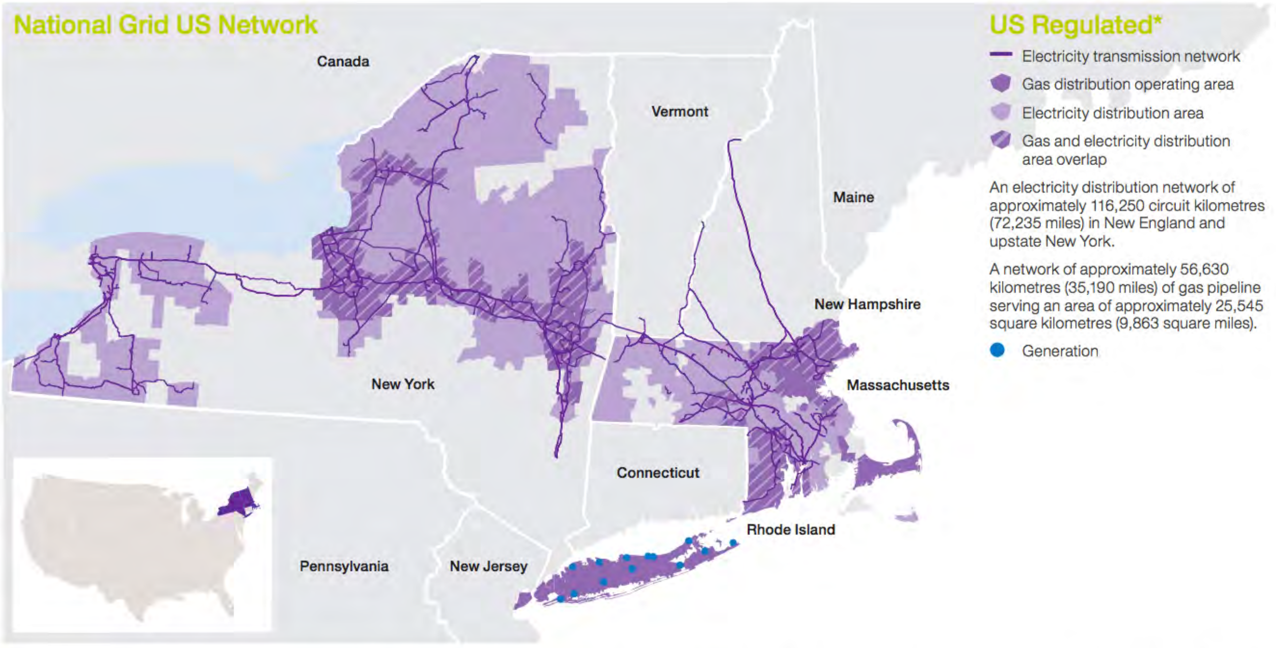
CONTENTS

Summary

National Grid's US electric system is comprised of four companies serving 3.5 million customers in Rhode Island, Massachusetts, and upstate New York. The four electric companies are: Narragansett Electric Company, serving 0.5 million customers Rhode Island[1], Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts and Niagara Mohawk Power Company serving 1.7 million customers in upstate New York. Figure 1[2] shows the Company's service territory in the U.S.



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Figure 1: National Grid U.S. Service Territory

Forecasting peak electric load is necessary for the Company's capital planning process so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.

The Company's[3] peak demand in 2021 was 1,818 MW on Wednesday, June 30 at hour-ending 16. This 2021 peak was 8% below the company's all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

This summer's weather for the Company peak was considered warmer than 'normal' (or average). The peak weather fell in the 83 percentile of peak weather over the last 20 years. This means that only 17%

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[1] National Grid is in the process of selling its Rhode Island service territory to Pennsylvania Power and Light Company. This transaction is targeted for completion in February 2022.
[2] National Grid also serves gas customers in these same states which are also shown on this map.
[3] Company refers to Narragansett Electric Company for the remainder of this report.

of summer peaks are expected to be warmer[4]. This year's peak is considered 89 MW above the peak the company would have experienced under normal weather. Thus, on an adjusted "normal" basis this year's peak was estimated to be 1,729 MW, a decrease of 1.6% compared to last year's adjusted peak.

NECO expects slightly growting peak load in the next five years, and bigger growth is expected in late years of the forecast horizon driven by growing demand and load adding from increasing penetration of transporation electrification. Summer peak remains to be the annual peak for the Company through out the forecast horizon. Figure 2 shows this forecast graphically.

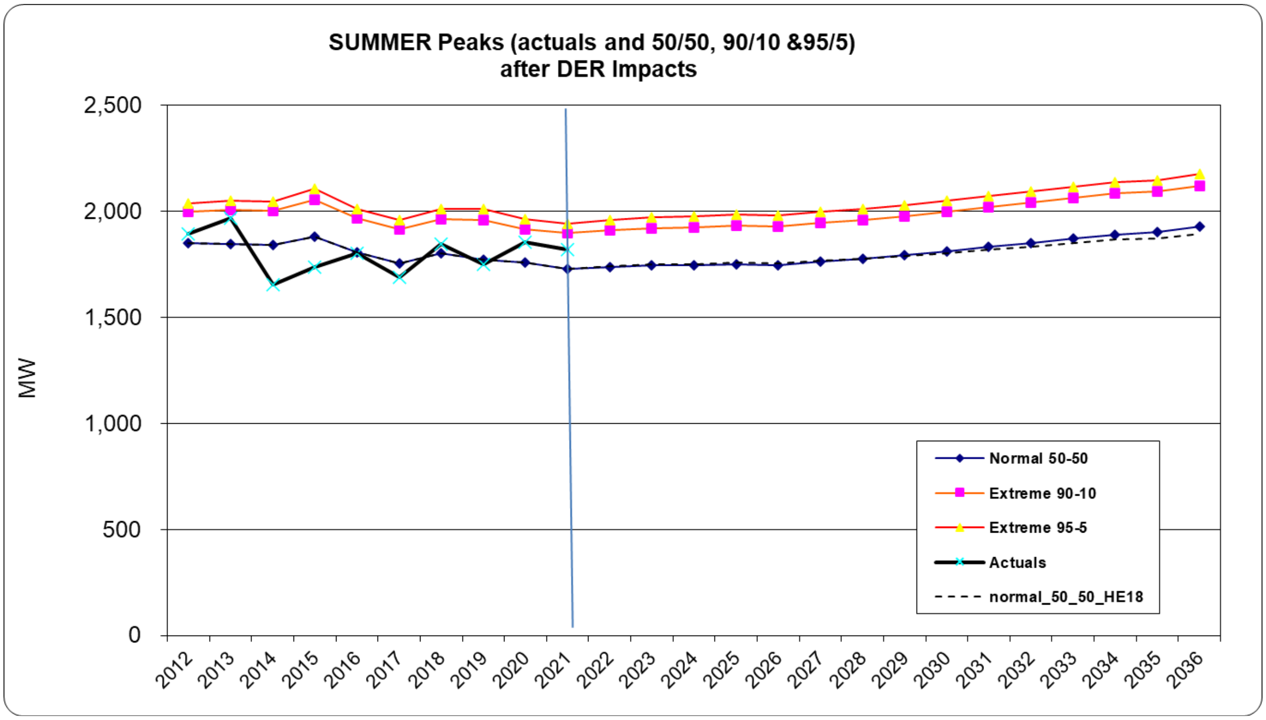

Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

This forecast incorporates the impacts of a changing hour of the peak over time. In general, due to increased solar photovoltaics (PV) and electric vehicles (EV) the hour of the peak moves from its current afternoon/early evening time to later in the evenining time. As this occurs, the impact of PV is less pronounced on the new peak hour. For comparison, the dasheds line in Figure 2 shows how the load at the 5-6 PM hour or hour-ending 18, where PV has more impact continues to decline over the planning horizon.

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[4] For planning purposes, network strategy uses a 90/10 for transmission planning and a 95/5 for distribution planning for weather extremes.

Forecast Methodology

The overall approach to the peak forecast is to relate (or regress) peak MWs to aggregate system energy and economic indicators (if appropriate).

The model is developed based on a "reconstructed" model of past load. That is, claimed energy efficiency, installed solar PV and demand response impacts are added back to the historical data set before the models are run. Electric vehicle impacts are removed from the historical data set. Electric heat pumps both add or remove load depending on the season (removed in winter and added in the summer). The statistical forecast is made based on the "reconstructed" data set. Then, the future cumulative estimates of savings or additions for these DERs are taken out or added to the statistical forecast to arrive at the final forecast. Hourly profiles for the DERs are applied to the hourly profiles for the loads to determine the annual peaks.

The results of this forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. Up until year 2019, distribution planning used the 95/5. The 50/50, or weather-normal scenario is used for capacity market, strategic scenarios, incentive mechanisms and other relevant work.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The Providence weather station is used for Rhode Island.

The weather variables used in the model include heating degree days for the winter months and a temperature-humidity index (THI)[5] for the summer months. Other variables such as maximum or minimum temperature on the peak day are also evaluated. These weather variables are from the actual days that each peak occurred in each season over the historical period. Summer THI uses a weighted three-day index (WTHI)[6] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[7].

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten-year period on average.
- Extreme 95/5 weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty-year period on average.

These normal and extremes are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Figure 3 shows the historical, weather-normal, and weather-extreme values for WTHI for the Company.

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[5] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.

[6] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.

[7] Normal distribution is assumed to derive the extreme weather scenarios. This probabilistic approach employs Z-scores and standard deviations to calculate the extreme weather scenarios.

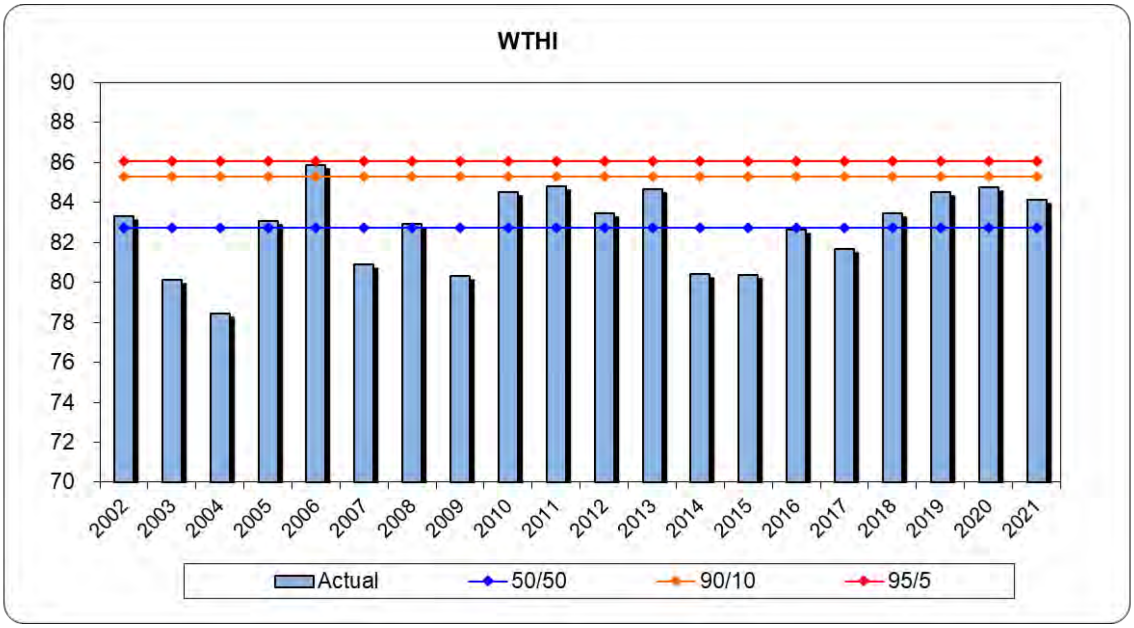


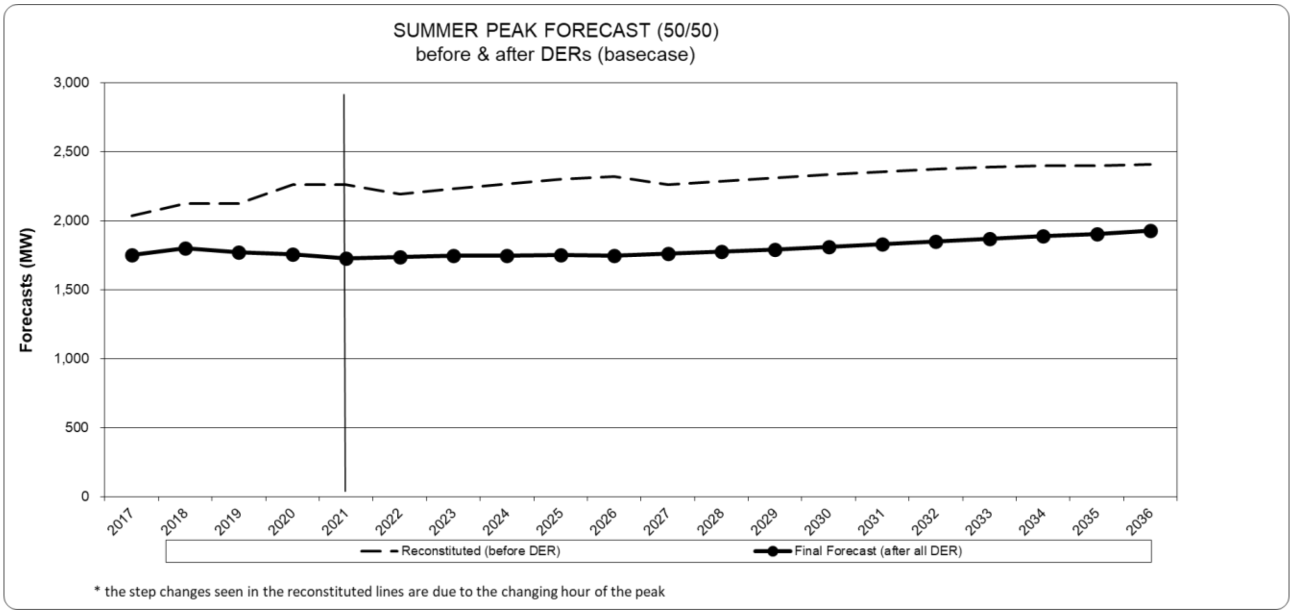
Figure 3: Actual, weather-normal and extreme WTHI

Distributed Energy Resources (DERs)

In Rhode Island, there are a number of policies, programs, and technologies that impact customer loads. These include, but are not limited to energy efficiency (EE), solar photovoltaics (PV), electric vehicles (EV), demand response (DR), electric storage (ES), and electric heat pumps (EH). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

A base case forecast is developed for each of the DERs and is part of the official forecast. For each of the DERs, a higher case and a lower case are developed, if appropriate. The inclusion of multiple cases for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions. The discussion below is based on the expected, or base case.

Figure 4 shows the expected load before and after DERs impacts and Figure 5 shows the impacts for the DERs each year. On average, DERs are expected to decrease future growth from 0.5% per year over the next five years to 0.2% per year. In the longer term – next fifteen years, the pre-DER growth rate is expected to be 0.4% per year. With the increasing penetration of beneficial electrification and the shift of expected peak hour to later of the day, the net savings from DERs is expected to become smaller and the post-DER growth rate is expected to be 0.7% per year.



* the step changes seen in the reconstituted lines are due to the changing hour of the peak

Figure 4: Annual loads before and after the impacts of DERs

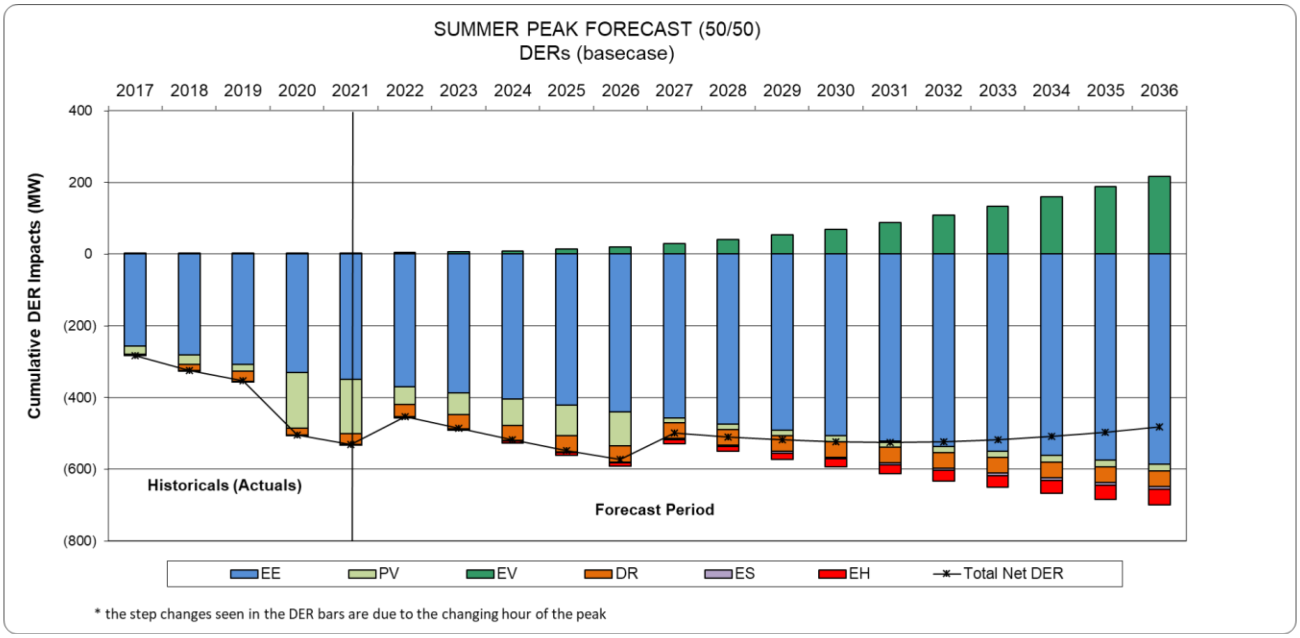


Figure 5: Annual impact of DERs

Each of the DERs is discussed next.

Energy Efficiency (EE)

National Grid has run EE programs in its Rhode Island jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term and through 2023, EE targets are based on the Company three-year plan. Post-2024 until 2028, the incremental value of persistent EE savings is held constant at 2023 levels. In 2028, persistent savings are still expected to continue to grow but at a slower rate each year. The growth rate slows by 5% annually to account for saturation of claimable savings.

Figure 5 above shows the expected load and energy efficiency program impacts to peaks by year for the base case. As of 2021, it is estimated that these EE programs have reduced load by 350 MW, or 15.5% compared to the counterfactual with no EE programs. By 2036, it is expected that this reduction will grow to 586 MW or 24.3% of what load would have been had these programs not been implemented. Over the fifteen-year planning horizon these reductions lower annual peak growth from 0.4% to negative 0.3% per year. Figure 6 presents the annual incremental (left) and cumulative (right) estimated EE summer MW savings.

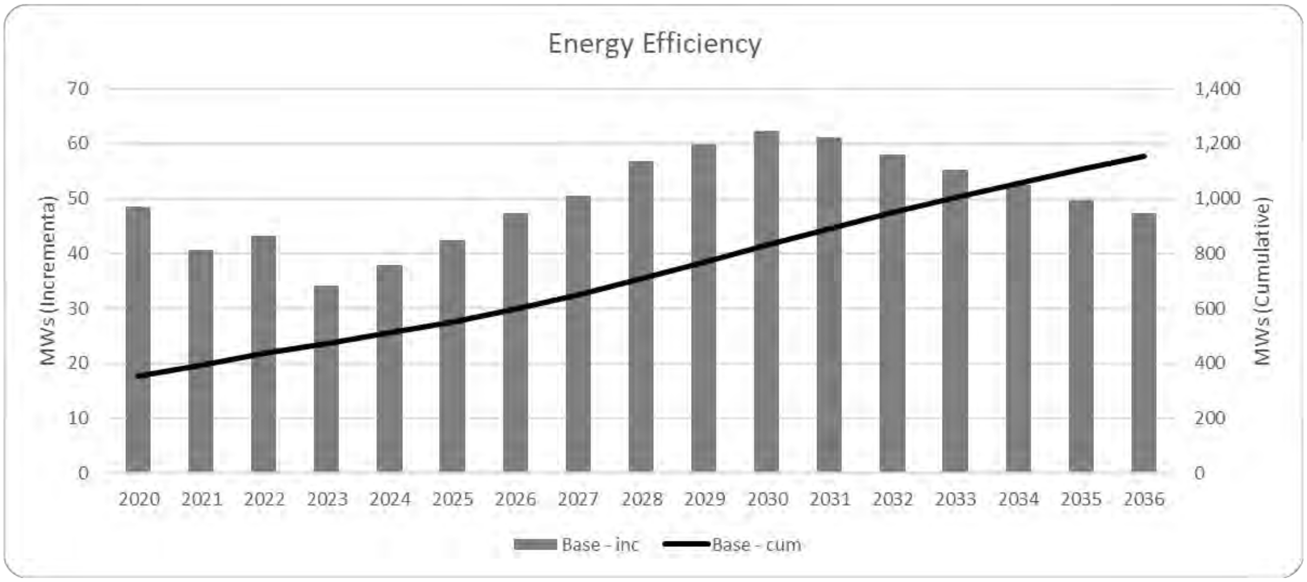


Figure 6: Energy efficiency summer MWs by year

Solar Photovoltaic (PV)[8]

Actual installed PV is tracked by the Company and used for the historical values in Figure 7. The projection for the future is based on an estimate of installations for units already in the application queue for the current year, then a continuation of those levels until year 2025, and then a slowly declining number of new annual installations to account for saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Figure 7 shows the projected connected PV installations. As of 2021, it is estimated about 394 MWs will have been connected, growing to 1,446 MW by the end of the planning period.

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[8] This discussion is limited to PV which is expected to reduce loads and would not include those PV installations considered to be supply by the ISO. This can include both 'behind-the-meter" and in "front-of-the-meter" (e.g. community solar which is allocated back to customers).

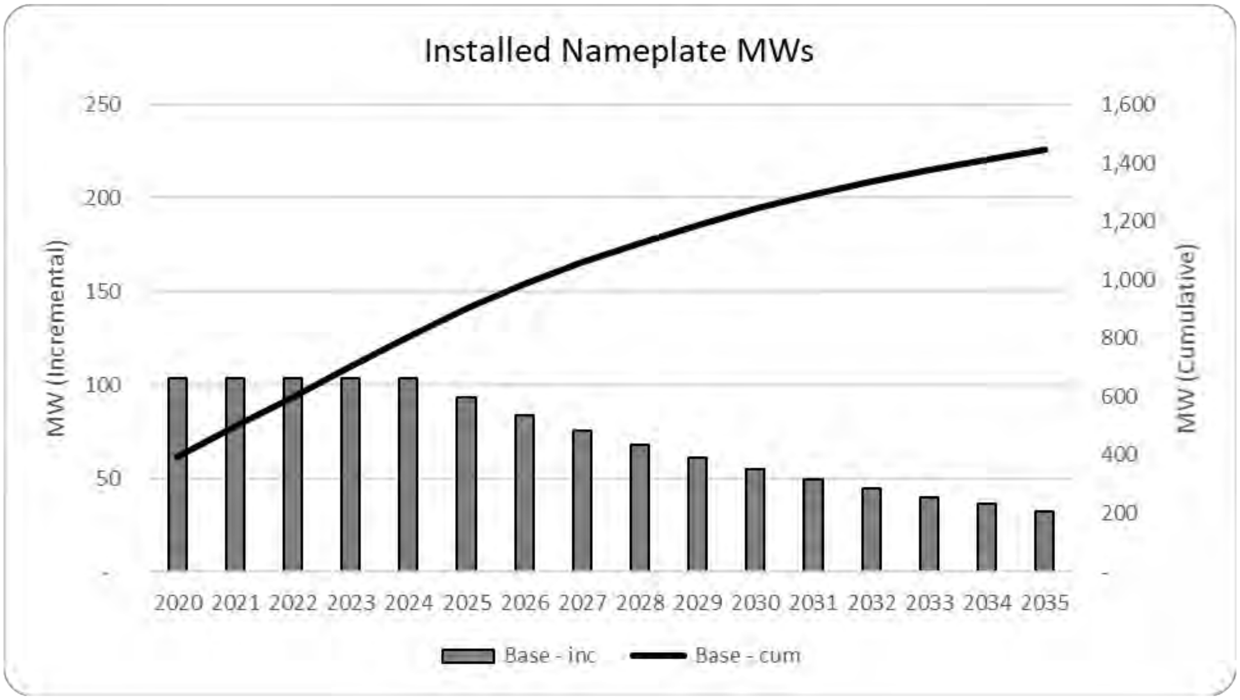

Figure 7: Solar-PV connected nameplate (AC) MW by year

While installed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less daylight.

Electric Vehicles (EV)

EVs increase peak load over time. EVs of interest are those that plug-in to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that have impacts on the electric network. In addition to light-duty EVs that the Company has been tracking and considering in its electric load forecasts, this year, the Company expand the scope from light-duty EVs only to include light-duty, medium-duty, heavy-duty EVs and electric buses, and consider the EV adoptions of BEVs and PHEVs in these four different vehicle types.

The light-duty EV base case is developed from Bloomberg's 2021 Long-term Electric Vehicle Outlook (BNEF-2021). The EV sales share of light-duty vehicles sales is assumed to follow BNEF-2021 estimates and vehicle scrap is also assumed based on BNEF-2021's estimates to develop the net EV in-operation numbers. In this case, the EV sales share of LDV sales is assumed to achieve 31% by 2030 and 59% by 2035. The adoptions of medium-duty EV (MDEV) and heavy- duty EV (HDEV) and E-buses are based on BNEF-2021 estimates and MOU policy targets. The base case is more of a market-driven case of adopting MDEV, HDEV, and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 16%, 17%, and 26% of MDV, HDV, and buses respectively by the year 2036.

Figure 8 shows the future estimated number of EVs in the Company's Rhode Island service territory. As of the end of 2021, it is estimated that about 4,500 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the service territory, growing to almost 255,000 by the end of the fifteen-year planning horizon.

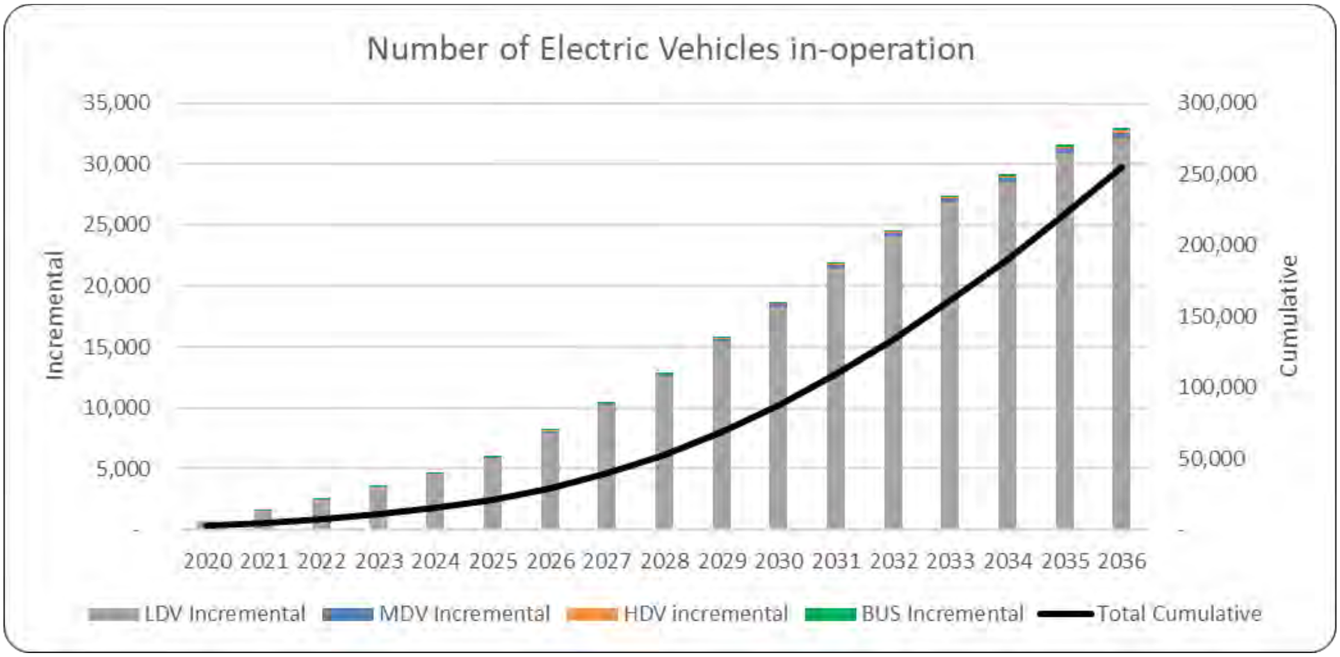

Figure 8: Number of Incremental and Cumulative EVs

It is estimated that these vehicles may have increased cumulative summer peak loads by about 1.6 MW as of 2021, increasing to 217.4 MW of cumulative peak load increase in 2036. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[9] electrification.

Demand Response (DR)

DR programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These resources must be dispatched, unlike the more passive energy efficiency programs that provide savings throughout the year. The DR programs enable utilities and the Independent System Operator (ISO) to act in response to a system reliability concern or economic (pricing) signal. During these events, customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

In general, there are two categories of Demand Response programs in Rhode Island. These are ISO programs and Company retail level programs.

The ISO programs, referred here as "wholesale DR", have been active for several years and were activated multiple times over that period. There were no ISO activations this year. The company's policy has been to add-back reductions from these dispatches to its reported system peak numbers. This is because the Company cannot dispatch the ISO resources so there is no guarantee that these ISO

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[9] Beneficial electrification is based on an overall portfolio of lowered carbon emissions from the transportation sector coupled with lower/carbon free generation of electricity in the power sector to support the charging of the EVs.

DR events would be at the times of Company peaks. Therefore, the company must plan assuming they are not called.

The Company recently began to run its own DR program at the 'retail', or customer level over the last few years. In contrast to the wholesale level DR programs implemented by the ISO, these programs are activated by the Company.

In 2021, estimated impact of the retail DR program was about 29 MW and is expected to grow to about 44 MW, or 1.9% of summer peak load by year 2025. No additional incremental DR MW is expected beyond that point because it is assumed that the program's market potential is at its maximum by then but the cumulated MW is expected to be carried through the rest of the forecast horizon.

Energy Storage (ES):

There is currently no explicit state energy storage policy targets in Rhode Island, nor any Company run programs to promote this DER. In year 2020 about 0.53 MW of storage was installed. By 2036, it is estimated that storage may help shave the summer peak load by about 7 MW, which is about 0.4% of what load would have been had these programs not been implemented. It is also noted that there is a small amount of storage being captured in the Company's Demand Response program in Rhode Island.

Electric Heat Pumps (EH):

The base case for years 2021 to 2030 are based on the Company's pro rata share of the ISO-NE heat electrification forecast, which is a projection for residential heat pumps installations in the state. Commercial heat pumps are not currently incentivized. Subsequent to this and through the end of the planning cycle in year 2036, incremental heat pumps continue to grow, but at a smaller amount each year to reflect a level of saturation. Figure 9 shows the annual number of electric heat pumps assumed for the forecast.

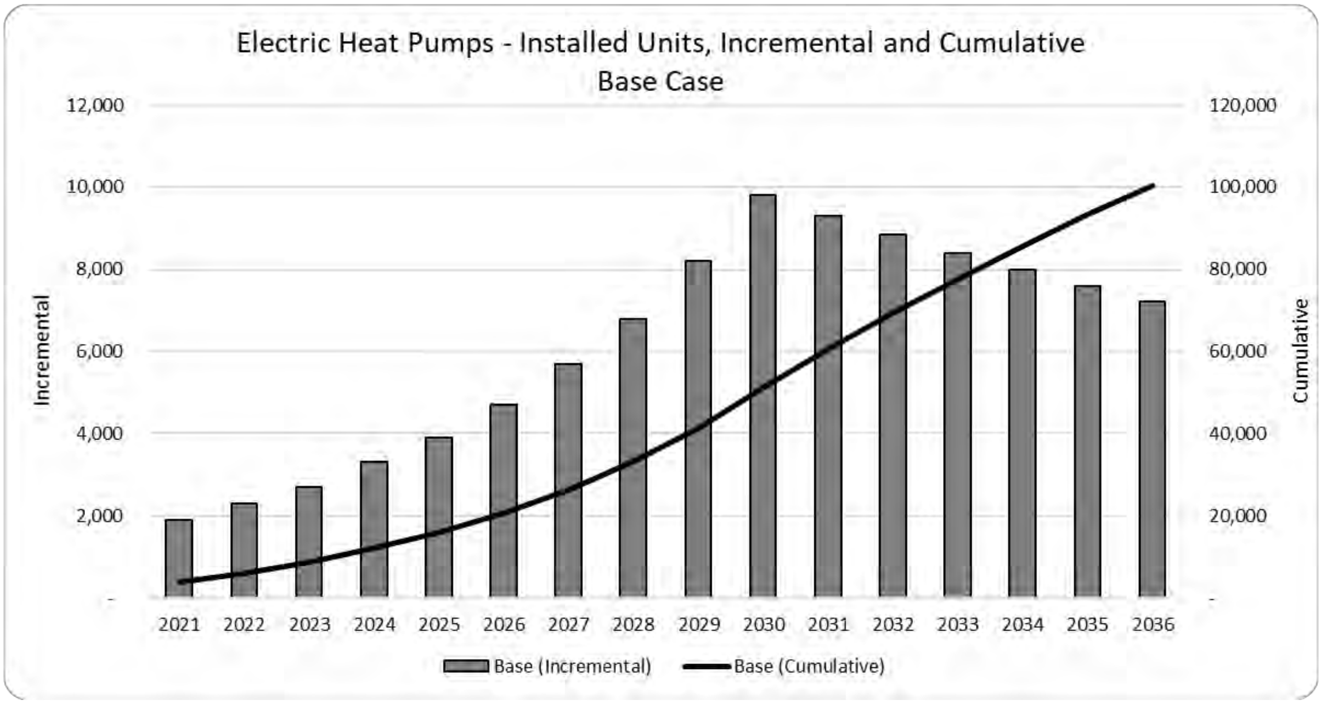

Figure 9: Number of electric heat pumps

All prior discussion on load & DERs above is limited to the base case. Additional higher and lower scenarios are provided later in this section (see 'DER scenarios') and in the Appendices.

Peak Day 24 Hourly Curves

While the single peak values discussed above are of major importance, the estimated impacts due to DERs on the load profile on these peak days is also significant. A 24-hour peak day load profile is provided below. This allows the Company to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more PV is added to the system, the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. As more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 10 shows the impact of the "24 hour" peak <u>summer</u> day for selected years over the planning horizon for the <u>base case</u> DERs.

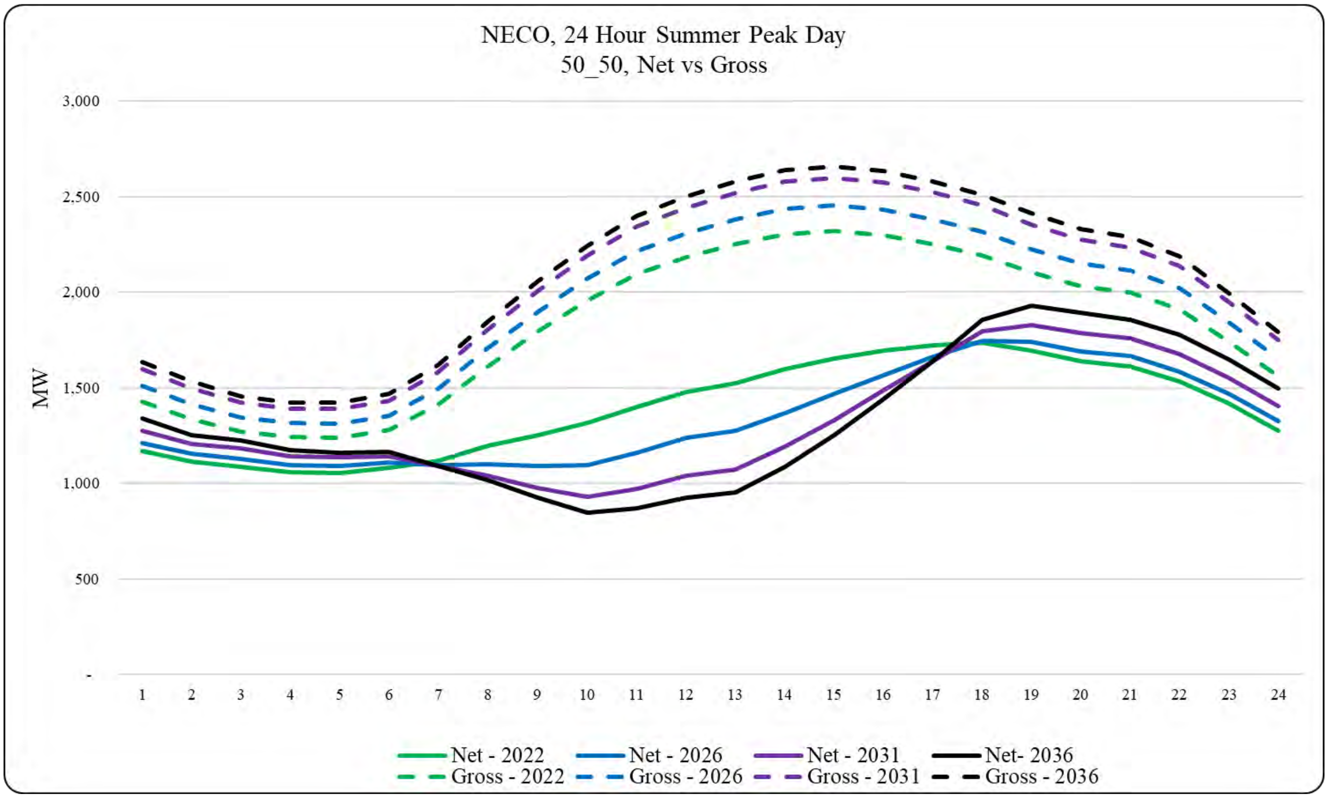

Figure 10: Peak Summer day hourly load, pre and post DERs

Figure 10 clearly shows how the expected DERs not only lower the loads, but also shift the hour of the peaks. "Gross" refers to loads before DER impacts and "Net' refers to loads after DER. The selected years are 2022, 2026, 2031 and 2036.

Figure 11 shows the impact of the "24 hour" peak <u>winter</u> day for selected years over the planning horizon with the base case DERs.

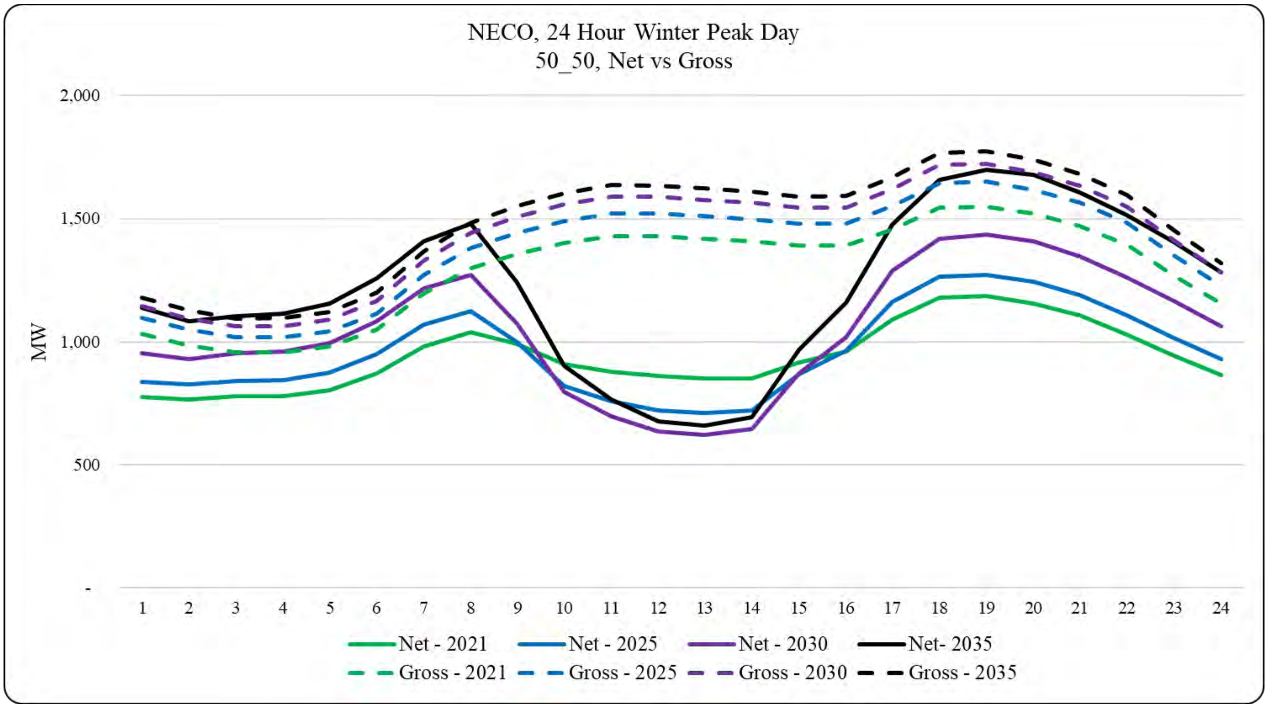

Figure 11: Peak Winter day hourly load, pre and post DERs

Figure 11 shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. The increasing penetration of electric heat pumps and electric vehicles will significantly increase the usage in later years. The figures above show the Gross and Net load profiles for the base case DERs.

Appendix C contains additional load shapes for other day types including: summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is no weekday business load.

DER Scenarios

So far, this report has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV, DR, and EH) also has a higher case and a lower case scenario, if appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[10].

Each of the various combinations of DERs scenarios – base, high and low – were modeled. This creates thousands of combinations. In order to assess the probabilities of any one of these scenarios occurring, each DER case was assigned a ‘probability level. For example, for the three EE cases, these were assigned 80% likelihood for the base case, 15% for the low case, and 5% for the high case. These assignments are based on group consensus with the SMEs for the DER and sum to 100%. For this report, the probabilities for each DER are assumed to be independent of each other. This process is repeated for each DER. Table 1 shows the probabilities used in the forecast.

Table 1, Probabilities for each DER case

RI	Low	Base	High
Energy Efficiency	15%	80%	5%
Solar - PV	5%	60%	35%
Electric Vehicles	20%	70%	10%
Demand Response	5%	85%	10%
Energy Storage	n/a	100%	n/a
Electric Heat Pumps	20%	75%	5%

Figure 12 shows the basecase (which is the most likely) in blue solid line and the maximum and minimum cases in red solid lines which provide the highest and lowest bounds for planning purposes. The base is the scenario with base cases from all DER technologies. The maximum load scenario / minimum DER saving scenario is the scenario with high cases for energy efficiency, solar PV, demand response, and energy storage; and low cases for electric vehicles and electric heat pumps. The minimum load scenario / maximum DER saving scenario is the scenario with low cases for energy efficiency, solar PV, demand response, and energy storage; and high cases for electric vehicles and electric heat pumps. It also shows the other more likely cases besides the basecase, and they are shown as black dashed lines.

The peak load five years from now or in year 2026, ranges from about 1,708 MW to 1,817 MW - a 109 MW spread, with the base case at 1,746 MW. The uncertainty increases over time, so that fifteen years from now or in year 2035, the range expands to from about 1,794 MW to 2,177 MW, or almost a 382 MW spread, with the base case at 1,928 MW. It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are very, very unlikely.

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[10] In this forecast, six DERs, each with three cases (ES only has base case) – base, high and low, creates 244 (3^5+1) cases for each weather scenario. With three weather scenarios 732 scenarios are generated for the Company.

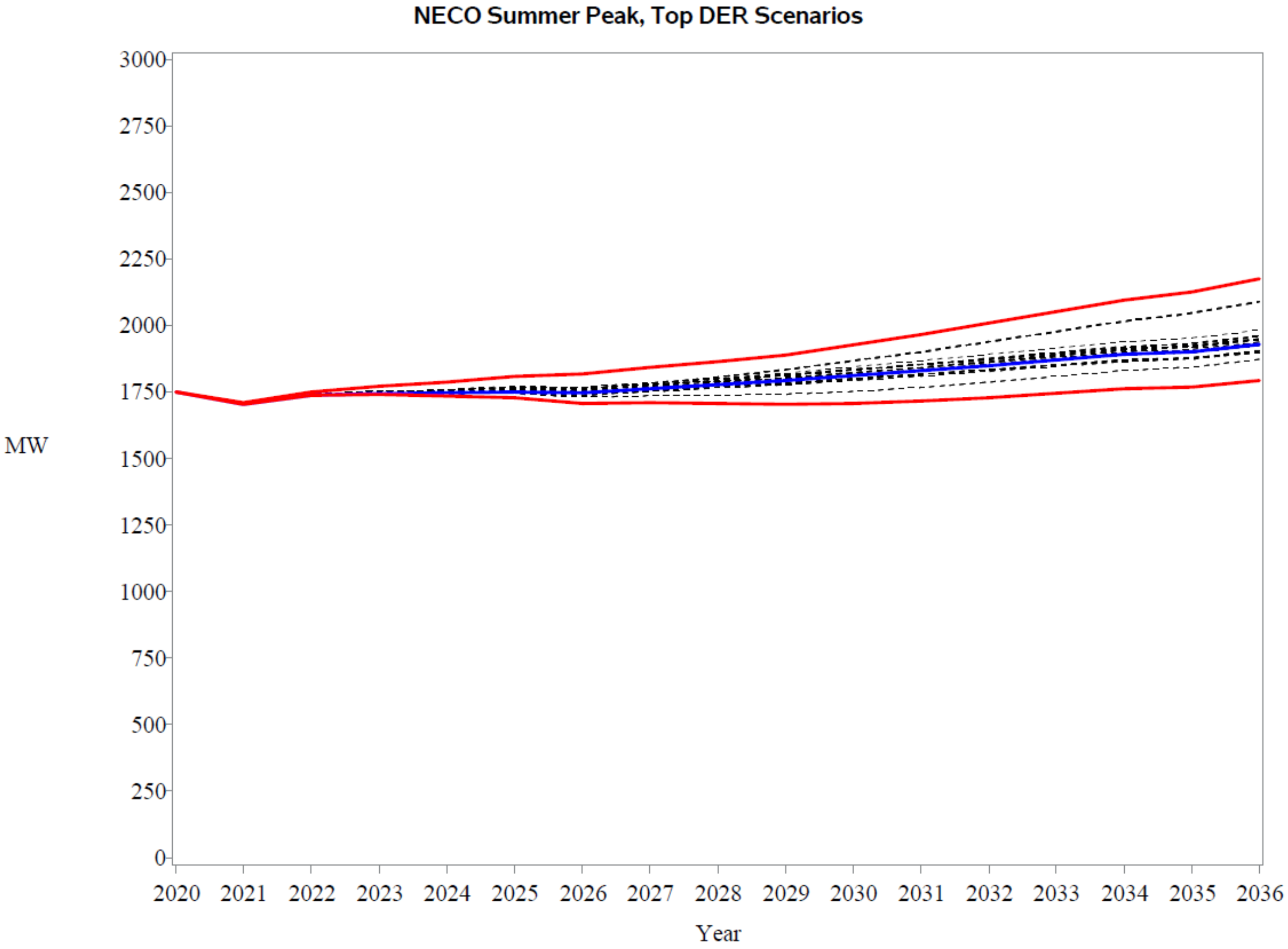
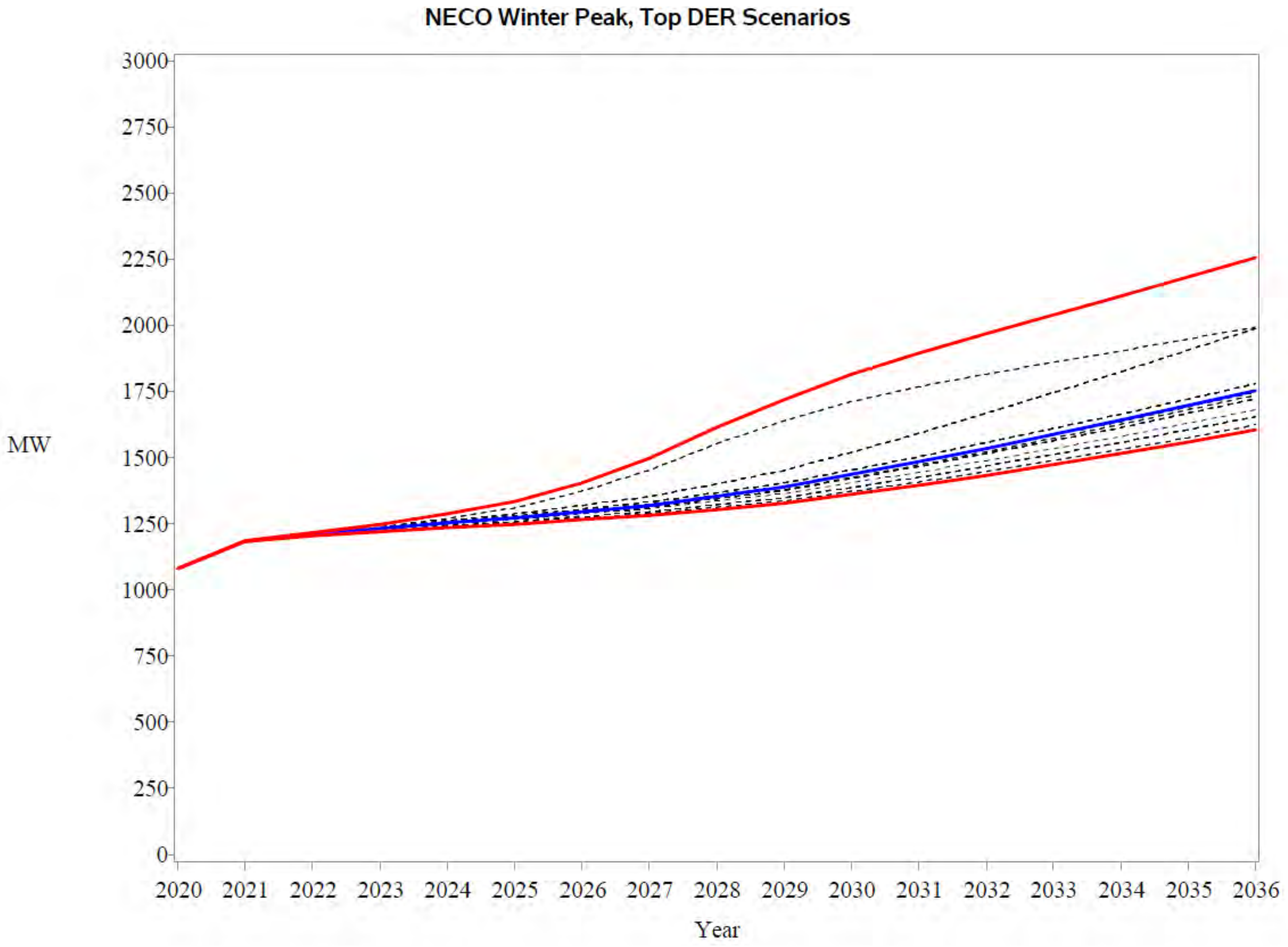


Figure 12: Summer Peaks (50/50), NET, selected DER scenarios

Although summer peaks remain to be the annual peak throughout the forecast horizon, winter peaks attract increasing interests with the increasing penetration in the heating electrification sector. Figure 13 shows the winter peak load of selected DER scenarios through the end of the forecast horizon in the same format as Figure 12. Please note, because the winter peak hour is expected to be hour-edning 19 or later, solar irradiance is not expected to be available for these projected peak hour thus there is no PV saving expected for the net peak hour in winter. There are two dash lines being closer to the maximum load scenario on the top, they represent the high electric heat pump case with base cases for other DER technologies and high electric vehicle case with base cases for other DER technologies.



While Figure 12 & 13 above show what the longer term annual single summer peaks and winter peaks look like, Figures 14 and 15 show what the 24-hour peak day profiles might be for selected years.

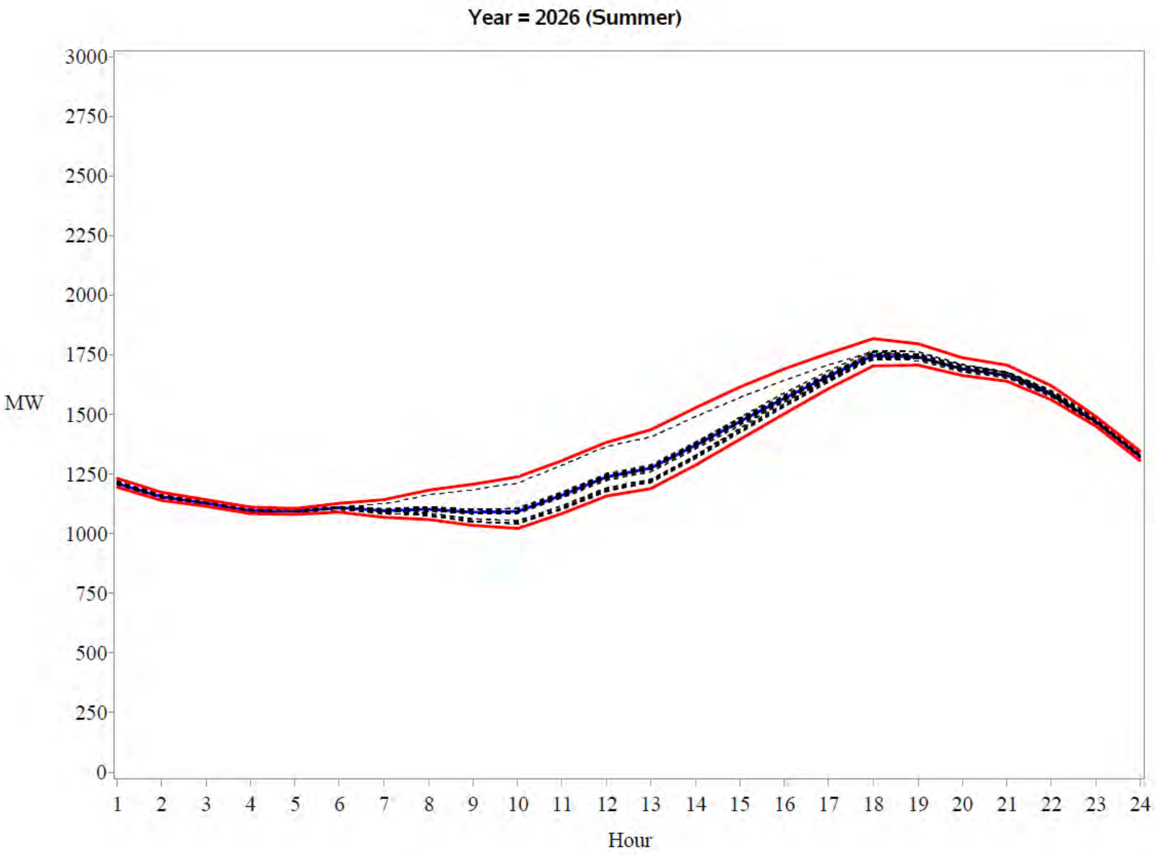


Figure 14: 50/50 case, net summer peak, w/range of DER scenarios, year 2026

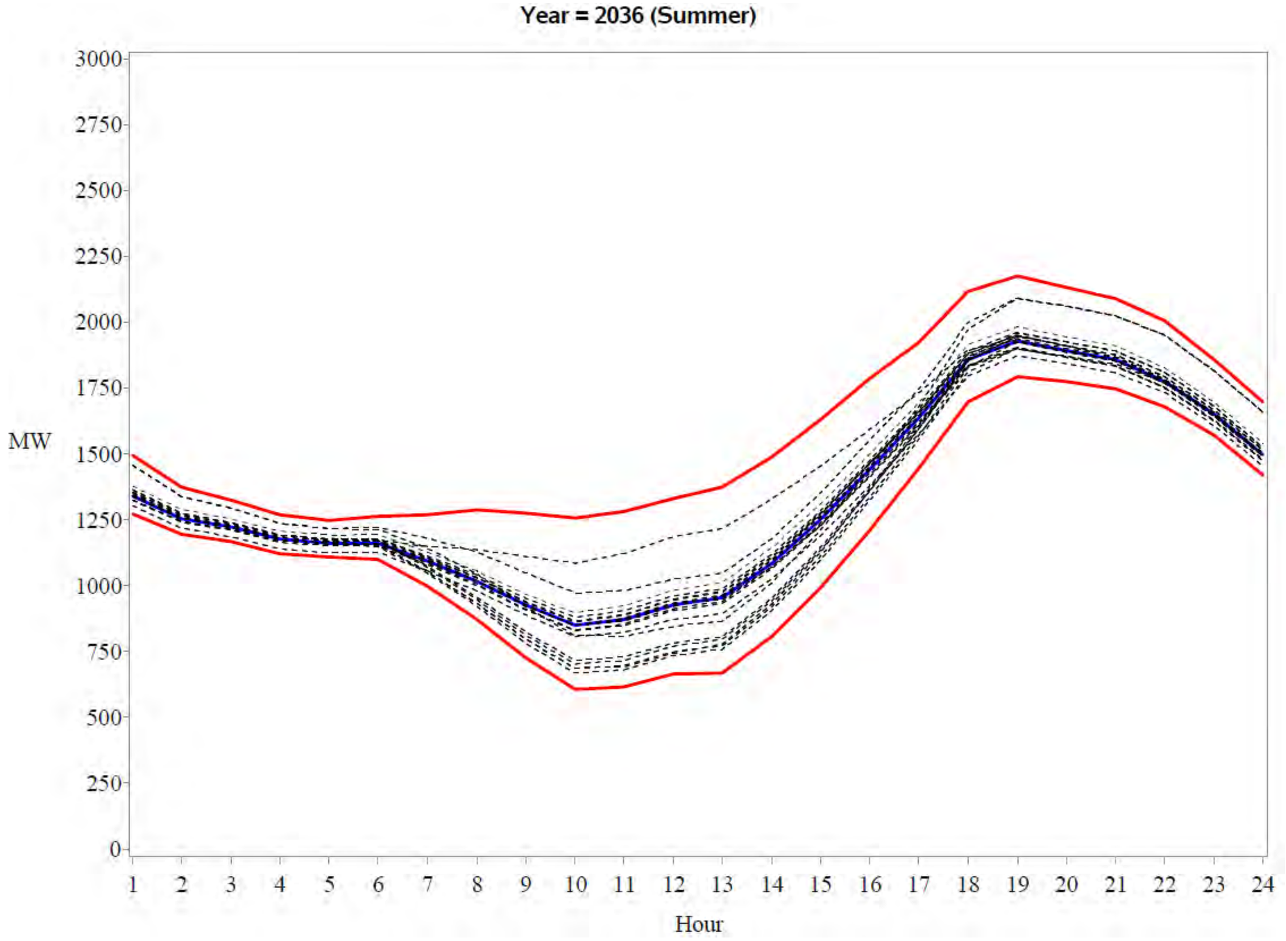


Figure 15: 50/50 case, net summer peak, w/range of DER scenarios, year 2036

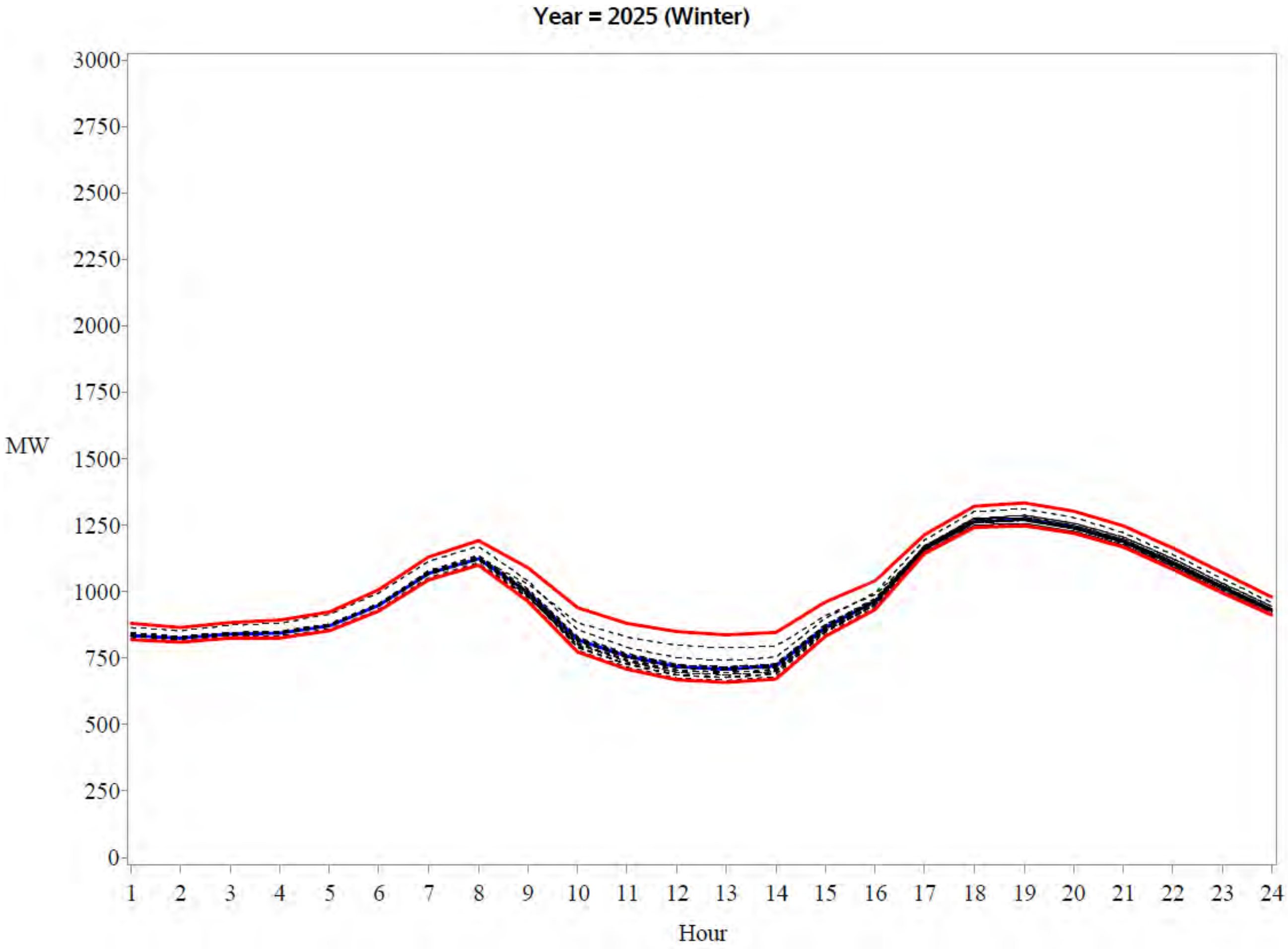


Figure 16: 50/50 case, net winter peak, w/range of DER scenarios, year 2025

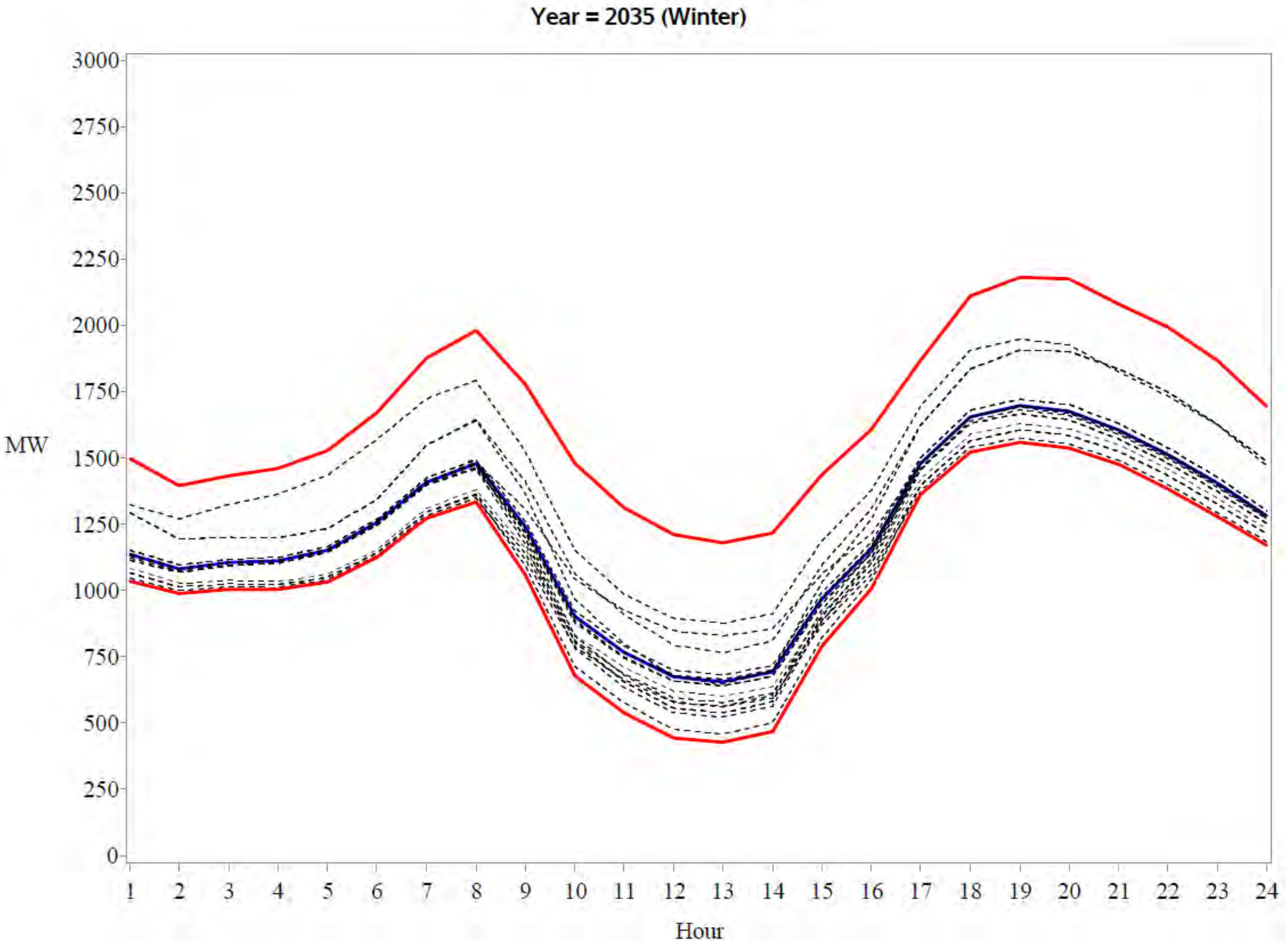


Figure 17: 50/50 case, net winter peak, w/range of DER scenarios, year 2035

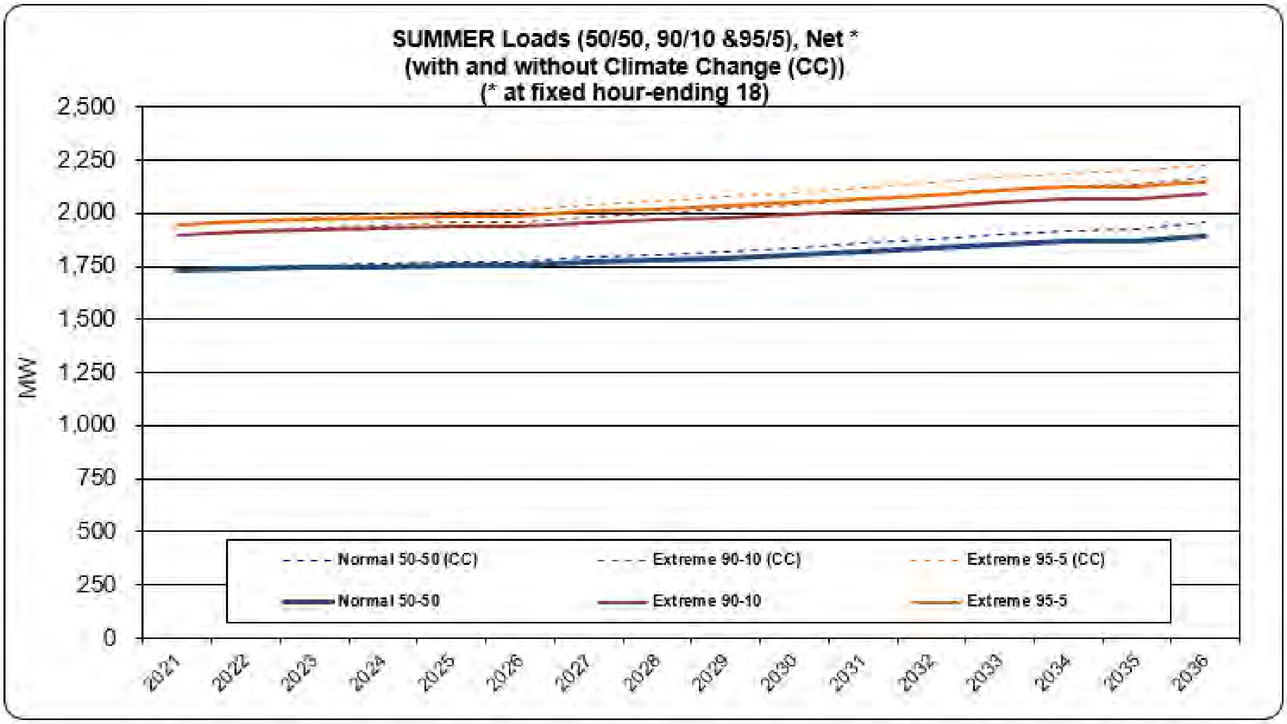
What becomes apparent is that the range of possible outcomes in the early years (Figure 14 &16), quickly increases fifteen years out (Figure 15 & 17). Note that the mid-day hours have a wider range of possible loads than other times of the day.

Appendices D and E describe the process for determining these scenarios and what the input cases look like.

The base case DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. The higher and lower scenarios are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive and may or may not capture some of the more ambitious and aspirational type DER scenarios associated with more renewables due to climate and other regional discussions. These can include, among other things, additional electrification of the transportation and heating sectors, and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

Climate Scenarios

The Company provides a climate change scenario based on possible changes in weather over time. This scenario shows potential changes to peak loads should average temperatures and volatility increase over time. Figure 18 compares the basecase, 50/50 summer peak forecast vs. alternative loads with higher average weather values.



* this table is summer loads fixed at HE18

Figure 18 Summer loads basecase and with climate change

The input assumption is a 0.7 degree rise in average temperatures per each ten years and a five percent increase in volatility over that same period. These increases are evenly divided across each year. No regional specific climate study was aware of, so the scenario was developed based on a study that the NYISO performed relative to climate change.[11] Average temperature is a factor in each of the three weather scenarios. The volatility value of 5% is currently a placeholder. The NYISO report did not assume a value for this, however, since the 90/10 and 95/5 scenarios in this report do include variance in the modeling, a placeholder value was assumed for this exercise.

Table 2 shows the differences between the loads in the basecase and the potential higher loads with the climate change assumptions for the three weather scenarios.

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[11] NYISO Climate Change Phase II Study, page 4, dated April 23,2020

Table 2 Comparison of loads between Basecase and Climate Change scenario for year 2036[12]

	50-50		90-10		95-5	
	Base	w/CC	Base	w/CC	Base	w/CC
Year 2036 (MWs)	1,895	1,955	2,095	2,169	2,152	2,229
Delta (MWs)		61		73		77
Delta (%)		3.2%		3.5%		3.6%

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[12] Please note, the numbers are based on the peak load at a fixed hour of the day and may not necessarily be the same as the predicted annual peak.

Comparison of 2021 Forecast to 2020 Forecast

Figure 19 provides a comparison of this year's summer peak (which is also the annual peak) forecast to last year's. Generally speaking, there is very little difference in the "Gross" forecasts (the forecast with the DERs reconstituted). The "Net" forecasts are slightly higher than forecasts released in 2020 mainly due to lower net DER impacts.

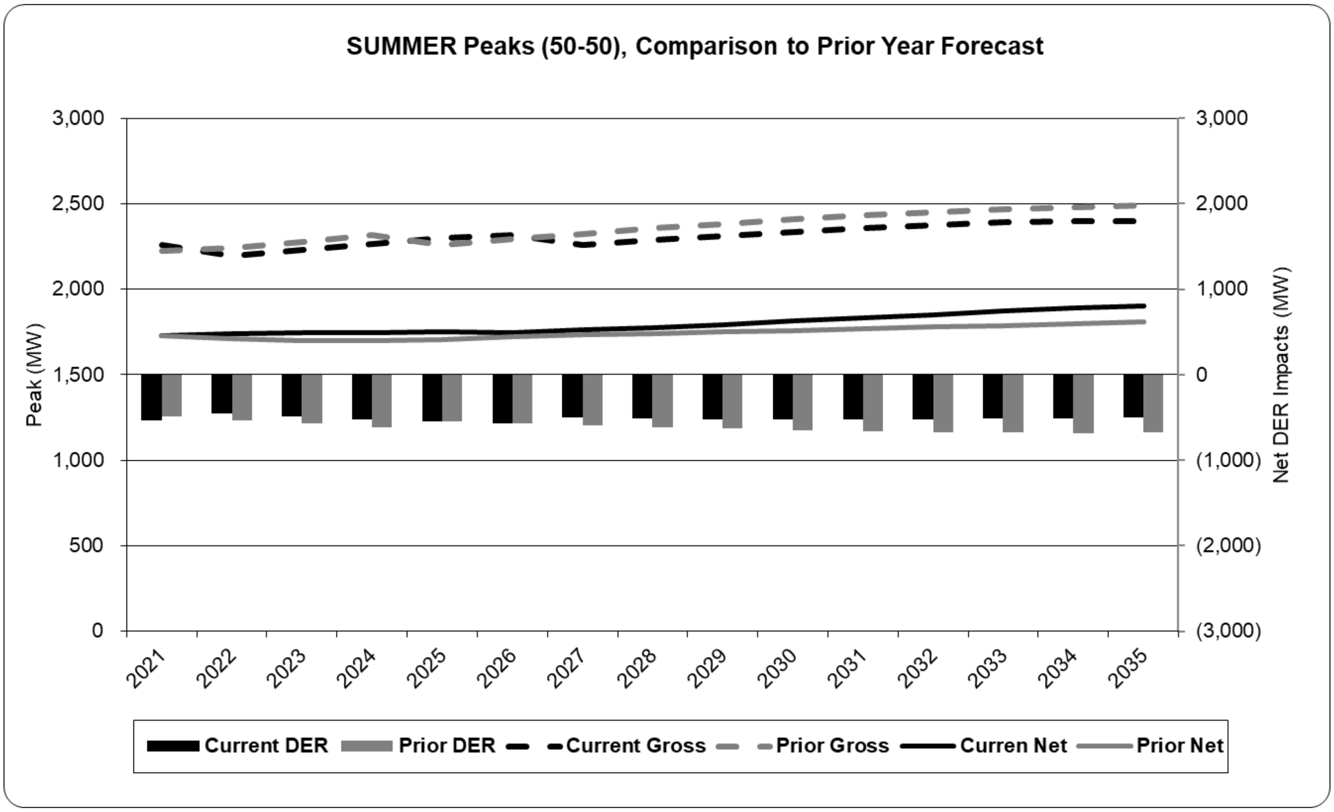


Figure 19 Comparison of current forecast to prior forecast, Gross and Net, Summer 50-50

Figure 20 provides a comparison of this year's winter peak forecast to last year's. The "Gross" forecasts (the forecast with the DERs reconstituted) are pretty close as last year's release. The "Net" forecasts are higher mainly driven by the lower net DER impacts.

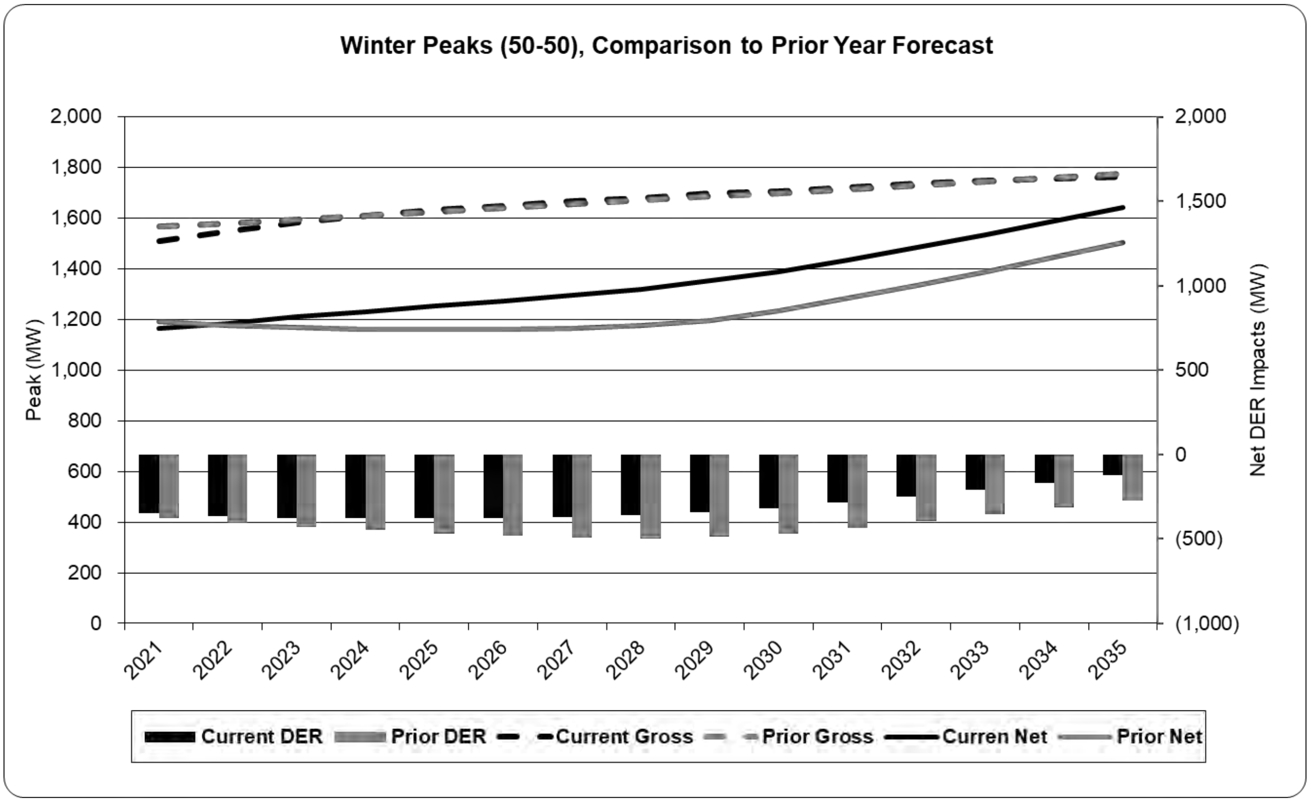


Figure 20 Comparison of current forecast to prior forecast, Gross and Net, Winter 50-50

Appendix A: Forecast Details

NECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2005	1,805		1,799		1,944		1,985		83.1
2006	1,985	10.0%	1,829	1.6%	1,958	0.7%	1,993	0.4%	85.9
2007	1,777	-10.5%	1,879	2.8%	2,025	3.5%	2,067	3.7%	80.9
2008	1,824	2.6%	1,843	-1.9%	1,983	-2.1%	2,022	-2.2%	82.9
2009	1,713	-6.1%	1,845	0.1%	2,007	1.2%	2,052	1.5%	80.3
2010	1,872	9.3%	1,829	-0.9%	1,989	-0.9%	2,034	-0.9%	84.5
2011	1,974	5.5%	1,847	1.0%	2,006	0.9%	2,051	0.8%	84.8
2012	1,892	-4.2%	1,850	0.1%	1,996	-0.5%	2,037	-0.7%	83.5
2013	1,965	3.9%	1,847	-0.1%	2,006	0.5%	2,050	0.7%	84.7
2014	1,653	-15.9%	1,841	-0.4%	2,001	-0.2%	2,046	-0.2%	80.4
2015	1,738	5.1%	1,882	2.2%	2,056	2.7%	2,105	2.9%	80.4
2016	1,803	3.8%	1,808	-3.9%	1,967	-4.3%	2,012	-4.4%	82.6
2017	1,688	-6.4%	1,754	-3.0%	1,913	-2.7%	1,958	-2.7%	81.7
2018	1,847	9.4%	1,802	2.8%	1,963	2.6%	2,009	2.6%	83.4
2019	1,750	-5.3%	1,771	-1.8%	1,959	-0.2%	2,013	0.2%	84.5
2020	1,855	6.0%	1,757	-0.8%	1,916	-2.2%	1,961	-2.6%	84.7
2021	1,819	-2.0%	1,729	-1.6%	1,896	-1.0%	1,943	-0.9%	84.1
2022	-	-	1,738	0.5%	1,910	0.7%	1,958	0.8%	-
2023	-	-	1,745	0.4%	1,920	0.5%	1,970	0.6%	-
2024	-	-	1,746	0.1%	1,924	0.2%	1,975	0.3%	-
2025	-	-	1,751	0.3%	1,933	0.4%	1,984	0.5%	-
2026	-	-	1,746	-0.3%	1,929	-0.2%	1,981	-0.2%	-
2027	-	-	1,761	0.9%	1,945	0.8%	1,998	0.9%	-
2028	-	-	1,777	0.9%	1,958	0.7%	2,010	0.6%	-
2029	-	-	1,793	0.9%	1,977	1.0%	2,029	1.0%	-
2030	-	-	1,812	1.0%	1,998	1.1%	2,051	1.1%	-
2031	-	-	1,830	1.0%	2,018	1.0%	2,071	1.0%	-
2032	-	-	1,851	1.1%	2,040	1.1%	2,094	1.1%	-
2033	-	-	1,872	1.2%	2,063	1.1%	2,117	1.1%	-
2034	-	-	1,891	1.0%	2,083	1.0%	2,137	1.0%	-
2035	-	-	1,902	0.5%	2,093	0.5%	2,148	0.5%	-
2036	-	-	1,928	1.4%	2,121	1.3%	2,176	1.3%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.4%	-0.2%	-0.2%
Avg. last 10 yrs	-0.7%	-0.6%	-0.5%
Avg. last 5 yrs	-0.9%	-0.7%	-0.7%
BASE 2021			
Avg. next 5 yrs	0.2%	0.3%	0.4%
Avg. next 10 yrs	0.6%	0.6%	0.6%
Avg. next 15 yrs	0.7%	0.7%	0.8%

WTHI

NORMAL	82.7
EXTREME 90/10	85.3
EXTREME 95/5	86.0

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response***

NECO SUMMER 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	DER IMPACTS EE	PV	EV	DR	ES	EH	DER
2005	1,826	1,799	1,826	1,826	1,826	1,826	1,826	**1,799**	(27)	(0)	0.0	0.0	0.0	0.0	(27)
2006	1,865	1,829	1,865	1,865	1,865	1,865	1,865	**1,829**	(37)	(0)	0.0	0.0	0.0	0.0	(37)
2007	1,926	1,880	1,926	1,926	1,926	1,926	1,926	**1,879**	(47)	(0)	0.0	0.0	0.0	0.0	(47)
2008	1,900	1,843	1,900	1,900	1,900	1,900	1,900	**1,843**	(57)	(0)	0.0	0.0	0.0	0.0	(57)
2009	1,916	1,846	1,915	1,916	1,916	1,916	1,916	**1,845**	(70)	(0)	0.0	0.0	0.0	0.0	(71)
2010	1,913	1,829	1,913	1,913	1,913	1,913	1,913	**1,829**	(84)	(1)	0.0	0.0	0.0	0.0	(84)
2011	1,944	1,848	1,944	1,944	1,944	1,944	1,944	**1,847**	(96)	(1)	0.0	0.0	0.0	0.0	(97)
2012	1,964	1,851	1,963	1,964	1,964	1,964	1,964	**1,850**	(113)	(1)	0.0	0.0	0.0	0.0	(114)
2013	1,989	1,852	1,984	1,989	1,989	1,989	1,989	**1,847**	(137)	(5)	0.1	0.0	0.0	0.0	(142)
2014	2,018	1,848	2,011	2,018	2,018	2,018	2,018	**1,841**	(170)	(7)	0.1	0.0	0.0	0.0	(177)
2015	2,096	1,894	2,084	2,096	2,096	2,096	2,096	**1,882**	(202)	(12)	0.2	0.0	0.0	0.0	(214)
2016	2,051	1,821	2,038	2,051	2,051	2,051	2,051	**1,808**	(230)	(14)	0.3	(0.0)	0.0	0.0	(243)
2017	2,037	1,781	2,014	2,037	2,032	2,037	2,037	**1,754**	(256)	(23)	0.4	(5.0)	0.0	0.0	(283)
2018	2,127	1,846	2,101	2,128	2,109	2,127	2,127	**1,802**	(281)	(26)	0.7	(17.6)	(0.0)	0.0	(325)
2019	2,124	1,817	2,104	2,125	2,097	2,124	2,124	**1,771**	(307)	(20)	1.3	(27.2)	(0.1)	(0.3)	(353)
2020	2,261	1,931	2,106	2,263	2,242	2,261	2,261	**1,757**	(330)	(155)	1.1	(19.2)	(0.5)	(0.8)	(505)
2021	2,260	1,911	2,109	2,262	2,231	2,259	2,259	**1,729**	(350)	(152)	1.6	(29.1)	(0.9)	(1.4)	(531)
2022	2,192	1,822	2,142	2,196	2,158	2,191	2,189	**1,738**	(370)	(50)	3.9	(33.4)	(1.3)	(2.5)	(453)
2023	2,231	1,845	2,170	2,237	2,193	2,229	2,227	**1,745**	(387)	(62)	6.1	(38.4)	(1.7)	(3.8)	(486)
2024	2,264	1,860	2,191	2,274	2,222	2,262	2,259	**1,746**	(404)	(73)	9.2	(42.4)	(2.1)	(5.3)	(518)
2025	2,299	1,877	2,214	2,312	2,255	2,296	2,292	**1,751**	(422)	(84)	13.3	(44.3)	(2.6)	(7.2)	(547)
2026	2,319	1,879	2,224	2,338	2,274	2,316	2,309	**1,746**	(440)	(95)	18.8	(44.3)	(3.0)	(9.3)	(573)
2027	2,260	1,802	2,247	2,290	2,216	2,257	2,249	**1,761**	(458)	(13)	30.2	(44.3)	(3.4)	(10.8)	(499)
2028	2,287	1,812	2,273	2,328	2,243	2,283	2,273	**1,777**	(475)	(14)	40.7	(44.3)	(3.8)	(13.6)	(510)
2029	2,312	1,820	2,297	2,365	2,267	2,307	2,294	**1,793**	(491)	(15)	53.8	(44.3)	(4.2)	(17.1)	(518)
2030	2,335	1,828	2,320	2,405	2,291	2,331	2,314	**1,812**	(507)	(16)	69.6	(44.3)	(4.7)	(21.2)	(523)
2031	2,355	1,834	2,339	2,444	2,311	2,350	2,330	**1,830**	(522)	(16)	88.2	(44.3)	(5.1)	(25.5)	(525)
2032	2,373	1,837	2,356	2,483	2,329	2,368	2,344	**1,851**	(536)	(17)	109.6	(44.3)	(5.5)	(29.5)	(523)
2033	2,389	1,840	2,371	2,523	2,345	2,383	2,356	**1,872**	(549)	(18)	133.5	(44.3)	(5.9)	(33.4)	(517)
2034	2,400	1,838	2,381	2,559	2,355	2,393	2,363	**1,891**	(562)	(18)	159.5	(44.3)	(6.3)	(37.1)	(509)
2035	2,399	1,824	2,380	2,586	2,354	2,392	2,358	**1,902**	(574)	(19)	187.6	(44.3)	(6.7)	(40.6)	(497)
2036	2,411	1,825	2,392	2,628	2,367	2,404	2,367	**1,928**	(586)	(19)	217.4	(44.3)	(7.1)	(43.9)	(483)

Avg. last 15 yrs	1.3%	0.3%	0.8%	1.3%	1.2%	1.3%	1.3%	-0.4%
Avg. last 10 yrs	1.5%	0.3%	0.8%	1.5%	1.4%	1.5%	1.5%	-0.7%
Avg. last 5 yrs	2.0%	1.0%	0.7%	2.0%	1.7%	2.0%	1.9%	-0.9%
BASE 2021								
Avg. next 5 yrs	0.5%	-0.3%	1.1%	0.7%	0.4%	0.5%	0.4%	0.2%
Avg. next 10 yrs	0.4%	-0.4%	1.0%	0.8%	0.4%	0.4%	0.3%	0.6%
Avg. next 15 yrs	0.4%	-0.3%	0.8%	1.0%	0.4%	0.4%	0.3%	0.7%

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

NECO
WINTER Peaks

after DER Impacts *

YEAR	Actuals		Normal 50-50		Extreme 10-90		Extreme 05-95		HDD_wtd
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	ACTUAL
2005	1,329		1,331		1,374		1,386		45.0
2006	1,329	0.0%	1,324	-0.5%	1,368	-0.5%	1,380	-0.5%	45.5
2007	1,352	1.7%	1,334	0.8%	1,376	0.7%	1,388	0.6%	44.8
2008	1,305	-3.5%	1,324	-0.8%	1,370	-0.5%	1,383	-0.4%	40.0
2009	1,294	-0.8%	1,336	0.9%	1,385	1.1%	1,398	1.1%	35.0
2010	1,315	1.6%	1,271	-4.9%	1,323	-4.5%	1,337	-4.3%	53.1
2011	1,243	-5.5%	1,259	-1.0%	1,307	-1.2%	1,321	-1.3%	41.6
2012	1,320	6.2%	1,298	3.1%	1,346	3.0%	1,360	2.9%	51.9
2013	1,328	0.7%	1,332	2.6%	1,381	2.6%	1,395	2.6%	43.9
2014	1,275	-4.0%	1,235	-7.2%	1,287	-6.8%	1,302	-6.6%	52.2
2015	1,223	-4.1%	1,208	-2.2%	1,253	-2.6%	1,266	-2.8%	55.0
2016	1,239	1.3%	1,287	6.5%	1,342	7.1%	1,358	7.2%	35.9
2017	1,277	3.1%	1,214	-5.7%	1,283	-4.4%	1,302	-4.1%	53.8
2018	1,301	1.9%	1,258	3.6%	1,318	2.8%	1,335	2.6%	51.0
2019	1,183	-9.1%	1,199	-4.7%	1,260	-4.4%	1,278	-4.3%	42.4
2020	1,181	-0.1%	1,166	-2.8%	1,222	-3.0%	1,238	-3.1%	44.6
2021	-	-	1,184	1.6%	1,245	1.9%	1,262	1.9%	-
2022		-	1,211	2.3%	1,276	2.5%	1,294	2.5%	
2023	-	-	1,232	1.7%	1,300	1.9%	1,319	1.9%	-
2024	-	-	1,254	1.7%	1,324	1.9%	1,344	1.9%	-
2025	-	-	1,272	1.5%	1,344	1.5%	1,365	1.6%	-
2026	-	-	1,297	1.9%	1,371	2.0%	1,392	2.0%	-
2027	-	-	1,320	1.8%	1,396	1.8%	1,417	1.8%	-
2028	-	-	1,354	2.6%	1,432	2.6%	1,454	2.6%	-
2029	-	-	1,388	2.5%	1,467	2.5%	1,490	2.4%	-
2030	-	-	1,436	3.4%	1,517	3.4%	1,540	3.3%	-
2031	-	-	1,485	3.4%	1,567	3.3%	1,590	3.3%	-
2032	-	-	1,536	3.4%	1,619	3.3%	1,643	3.3%	-
2033	-	-	1,589	3.4%	1,673	3.3%	1,697	3.3%	-
2034	-	-	1,641	3.3%	1,727	3.2%	1,751	3.2%	-
2035	-	-	1,697	3.4%	1,784	3.3%	1,808	3.3%	-
2036	-	-	1,754	3.3%	1,841	3.2%	1,866	3.2%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg. last 15 yrs	-0.9%	-0.8%	-0.7%
Avg. last 10 yrs	-0.9%	-0.8%	-0.8%
Avg. last 5 yrs	-0.7%	-0.5%	-0.4%
BASE 2020			
Avg. next 5 yrs	1.8%	1.9%	2.0%
Avg. next 10 yrs	2.1%	2.2%	2.2%
Avg. next 15 yrs	2.5%	2.6%	2.6%

HDD_wtd

NORMAL	44.9
EXTREME 90/10	54.5
EXTREME 95/5	57.3

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heap pumps, and company demand response (solar and demand response are zero at times of winter peak)***

NECO WINTER 50/50 Peaks (MW) (before & after DERs)

	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2005	1,366	1,331	1,366	1,366	1,366	1,366	1,366	**1,331**	(35)	0	0.0	0.0	0.0	0.0	(35)
2006	1,370	1,324	1,370	1,370	1,370	1,370	1,370	**1,324**	(46)	0	0.0	0.0	0.0	0.0	(46)
2007	1,391	1,334	1,391	1,391	1,391	1,391	1,391	**1,334**	(56)	0	0.0	0.0	0.0	0.0	(56)
2008	1,390	1,324	1,390	1,390	1,390	1,390	1,390	**1,324**	(66)	0	0.0	0.0	0.0	0.0	(65)
2009	1,416	1,336	1,416	1,416	1,416	1,416	1,416	**1,336**	(79)	0	0.0	0.0	0.0	0.0	(79)
2010	1,362	1,271	1,362	1,362	1,362	1,362	1,362	**1,271**	(91)	0	0.0	0.0	0.0	0.0	(91)
2011	1,363	1,259	1,363	1,363	1,363	1,363	1,363	**1,259**	(104)	0	0.0	0.0	0.0	0.0	(104)
2012	1,421	1,298	1,421	1,421	1,421	1,421	1,421	**1,298**	(124)	0	0.1	0.0	0.0	0.0	(123)
2013	1,484	1,332	1,484	1,485	1,484	1,484	1,484	**1,332**	(153)	0	0.1	0.0	0.0	0.0	(153)
2014	1,432	1,235	1,432	1,433	1,432	1,432	1,432	**1,235**	(197)	0	0.3	0.0	0.0	0.0	(197)
2015	1,433	1,208	1,433	1,434	1,433	1,433	1,433	**1,208**	(226)	0	0.5	0.0	0.0	0.0	(225)
2016	1,539	1,286	1,539	1,539	1,539	1,539	1,539	**1,287**	(252)	0	0.6	0.0	0.0	0.0	(252)
2017	1,493	1,213	1,493	1,495	1,493	1,493	1,493	**1,214**	(281)	0	1.1	0.0	0.0	0.0	(279)
2018	1,563	1,256	1,563	1,564	1,563	1,563	1,563	**1,258**	(306)	0	1.4	0.0	(0.0)	0.0	(305)
2019	1,525	1,195	1,525	1,527	1,525	1,525	1,527	**1,199**	(330)	0	2.1	0.0	(0.2)	2.2	(326)
2020	1,511	1,160	1,511	1,514	1,511	1,510	1,515	**1,166**	(351)	0	2.8	0.0	(0.7)	3.7	(345)
2021	1,550	1,173	1,550	1,554	1,550	1,548	1,557	**1,184**	(376)	0	4.4	0.0	(1.1)	7.5	(365)
2022	1,585	1,193	1,585	1,592	1,585	1,583	1,597	**1,211**	(391)	0	7.1	0.0	(1.5)	12.1	(374)
2023	1,610	1,205	1,610	1,621	1,610	1,608	1,627	**1,232**	(404)	0	11.1	0.0	(1.9)	17.5	(378)
2024	1,632	1,215	1,632	1,649	1,632	1,630	1,657	**1,254**	(417)	0	16.6	0.0	(2.3)	24.1	(379)
2025	1,649	1,219	1,649	1,673	1,649	1,646	1,681	**1,272**	(430)	0	23.9	0.0	(2.7)	31.9	(377)
2026	1,668	1,225	1,668	1,702	1,668	1,665	1,709	**1,297**	(443)	0	33.9	0.0	(3.2)	41.3	(371)
2027	1,680	1,224	1,680	1,727	1,680	1,676	1,733	**1,320**	(456)	0	46.9	0.0	(3.6)	52.7	(360)
2028	1,697	1,229	1,697	1,761	1,697	1,693	1,764	**1,354**	(469)	0	63.2	0.0	(4.0)	66.3	(343)
2029	1,707	1,227	1,707	1,790	1,707	1,703	1,790	**1,388**	(480)	0	83.4	0.0	(4.4)	82.7	(319)
2030	1,722	1,231	1,722	1,830	1,722	1,718	1,825	**1,436**	(492)	0	107.6	0.0	(4.8)	102.3	(286)
2031	1,735	1,233	1,735	1,871	1,735	1,730	1,856	**1,485**	(502)	0	136.1	0.0	(5.2)	120.9	(250)
2032	1,747	1,235	1,747	1,915	1,747	1,741	1,886	**1,536**	(512)	0	168.2	0.0	(5.6)	138.6	(211)
2033	1,757	1,235	1,757	1,961	1,757	1,751	1,912	**1,589**	(522)	0	204.1	0.0	(6.1)	155.4	(168)
2034	1,764	1,234	1,764	2,007	1,764	1,758	1,936	**1,641**	(531)	0	242.7	0.0	(6.5)	171.4	(123)
2035	1,773	1,233	1,773	2,057	1,773	1,766	1,959	**1,697**	(539)	0	284.5	0.0	(6.9)	186.5	(75)
2036	1,780	1,232	1,780	2,108	1,780	1,772	1,981	**1,754**	(548)	0	328.4	0.0	(7.3)	201.0	(26)
	-														
Avg. last 15 yrs	0.7%	-0.9%	0.7%	0.7%	0.7%	0.7%	0.7%	-0.9%							
Avg. last 10 yrs	1.0%	-0.9%	1.0%	1.1%	1.0%	1.0%	1.1%	-0.9%							
Avg. last 5 yrs	1.1%	-0.8%	1.1%	1.1%	1.1%	1.1%	1.1%	-0.7%							
BASE 2020															
Avg. next 5 yrs	1.8%	1.0%	1.8%	2.0%	1.8%	1.7%	2.1%	1.8%							
Avg. next 10 yrs	1.3%	0.6%	1.3%	1.9%	1.3%	1.3%	1.9%	2.1%							
Avg. next 15 yrs	1.1%	0.4%	1.1%	2.1%	1.1%	1.0%	1.7%	2.5%							

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Appendix B: Historical Peaks Days and Hours

Summer Peaks

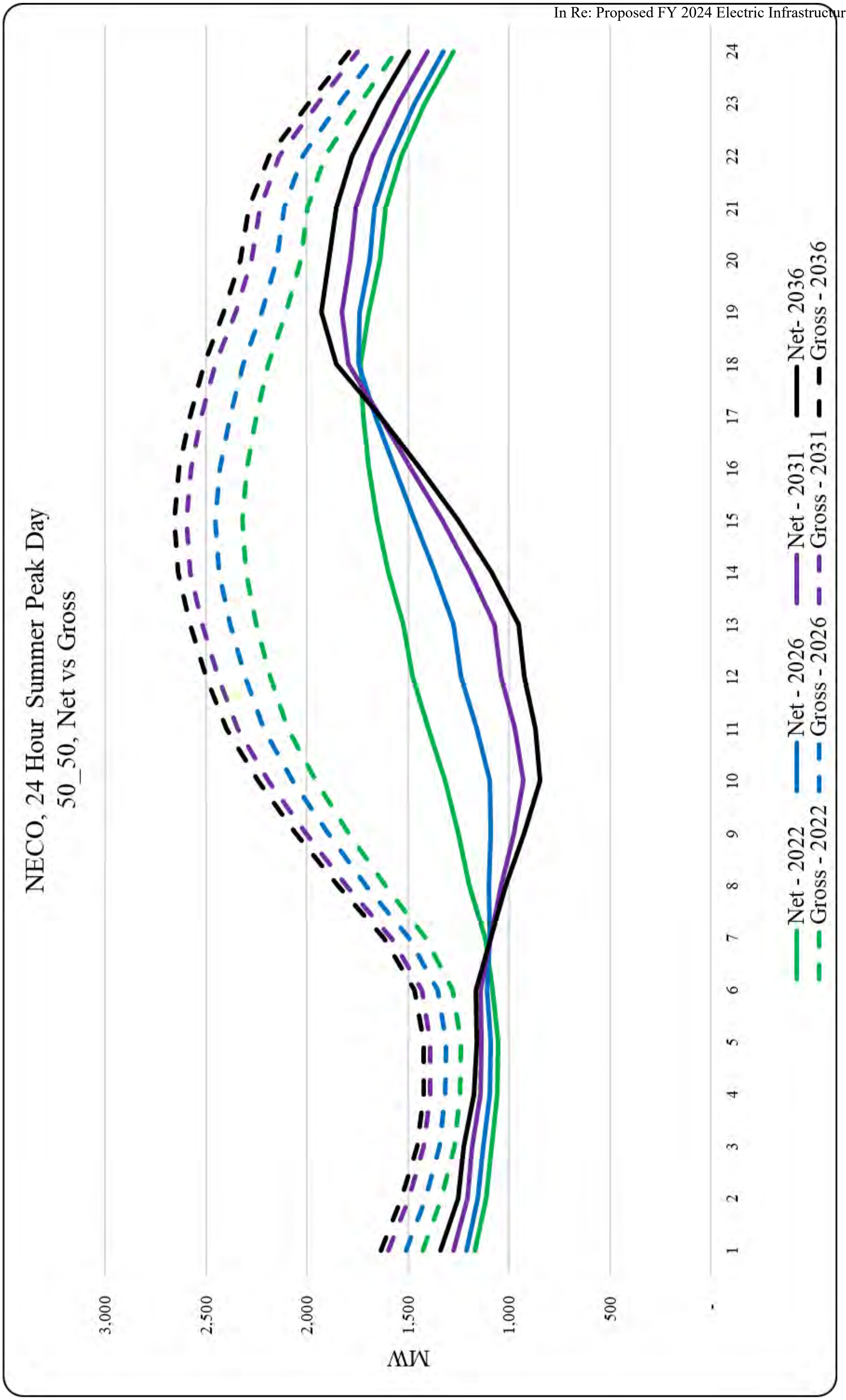
year	date	hour
2003	8/22/2003	15
2004	8/30/2004	15
2005	8/5/2005	15
2006	8/2/2006	15
2007	8/3/2007	15
2008	6/10/2008	15
2009	8/18/2009	15
2010	7/6/2010	15
2011	7/22/2011	16
2012	7/18/2012	15
2013	7/19/2013	15
2014	9/2/2014	16
2015	7/20/2015	15
2016	8/12/2016	16
2017	7/20/2017	16
2018	8/29/2018	17
2019	7/21/2019	18
2020	7/28/2020	15
2021	6/30/2021	16

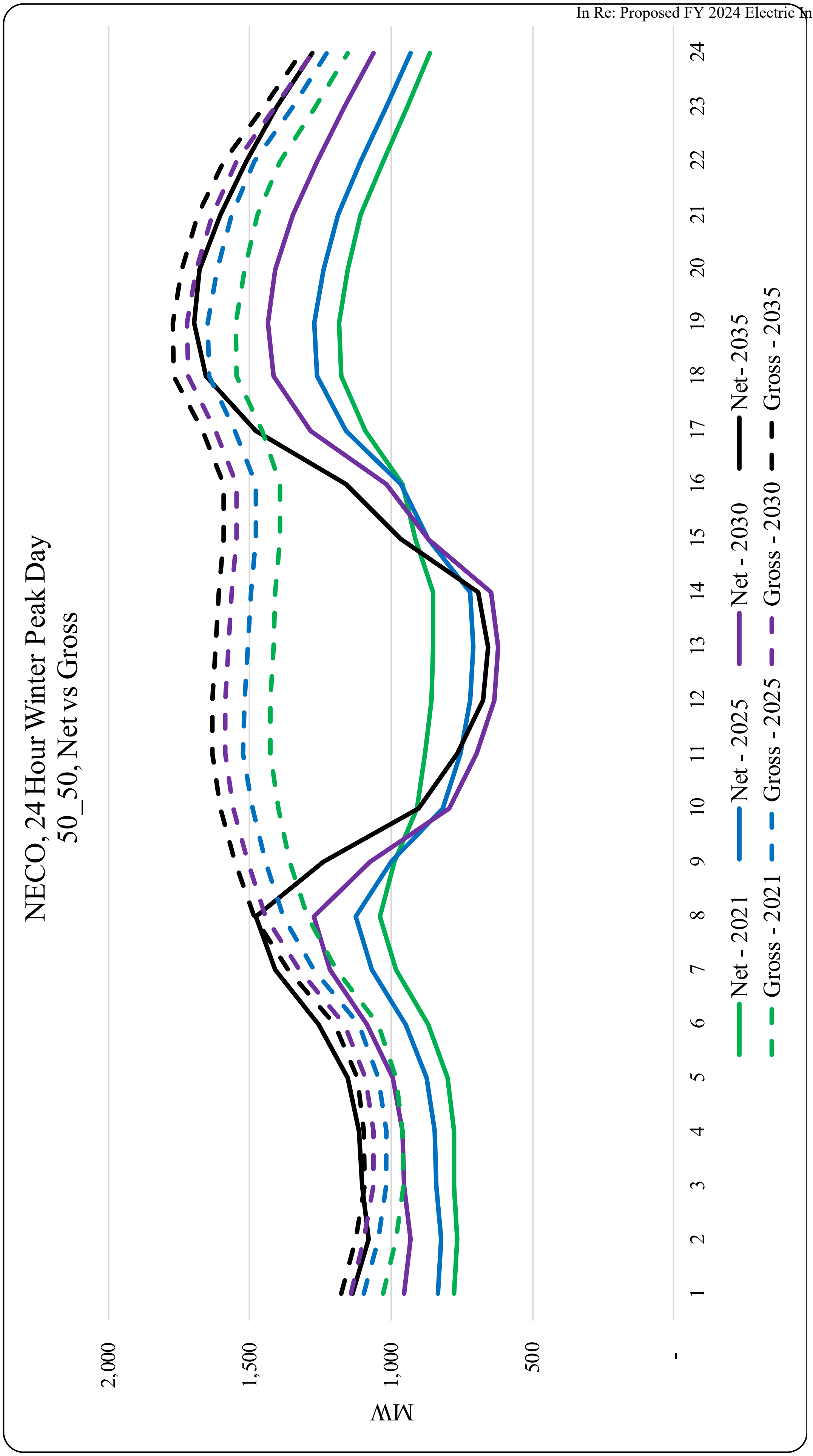
Winter Peaks

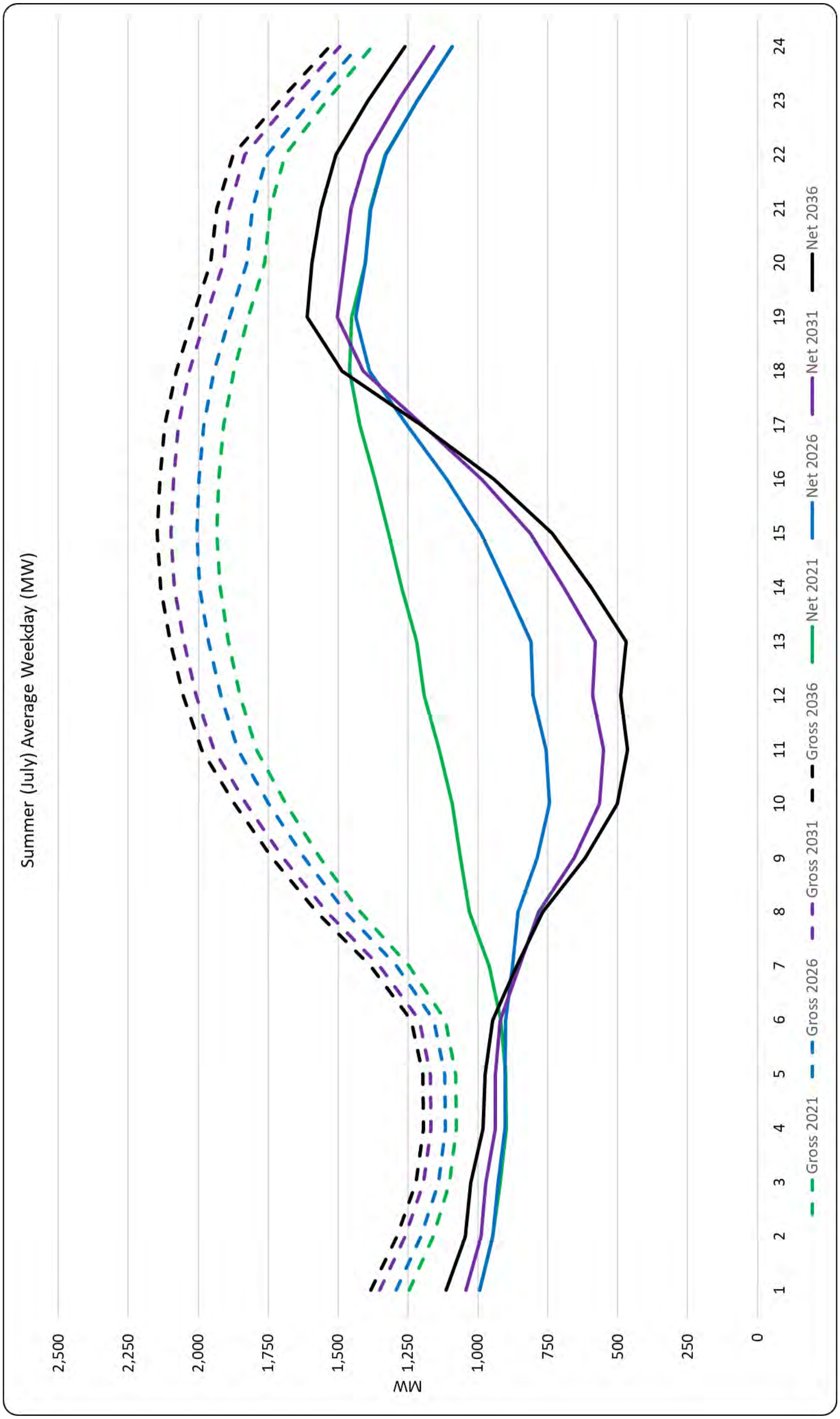
year	date	hour
2002	3/3/2003	19
2003	1/15/2004	19
2004	12/20/2004	19
2005	12/14/2005	18
2006	2/5/2007	19
2007	1/3/2008	19
2008	12/8/2008	18
2009	12/29/2009	19
2010	1/24/2011	19
2011	1/4/2012	18
2012	1/24/2013	19
2013	12/17/2013	18
2014	1/8/2015	18
2015	2/15/2016	19
2016	12/15/2016	18
2017	1/2/2018	19
2018	1/21/2019	18
2019	12/19/2019	19
2020	1/29/2021	19

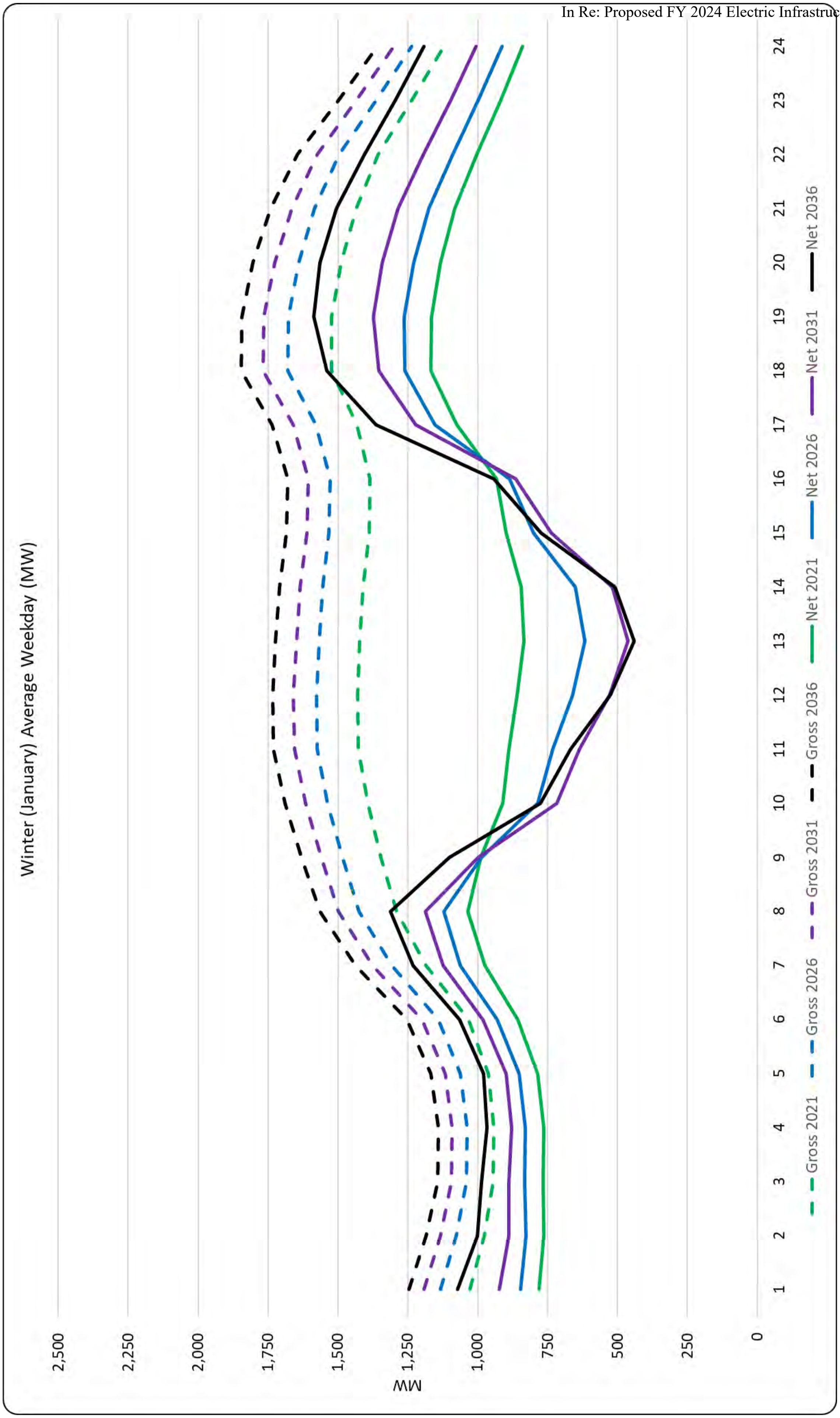
Appendix C: Load Shapes for Typical Day Types

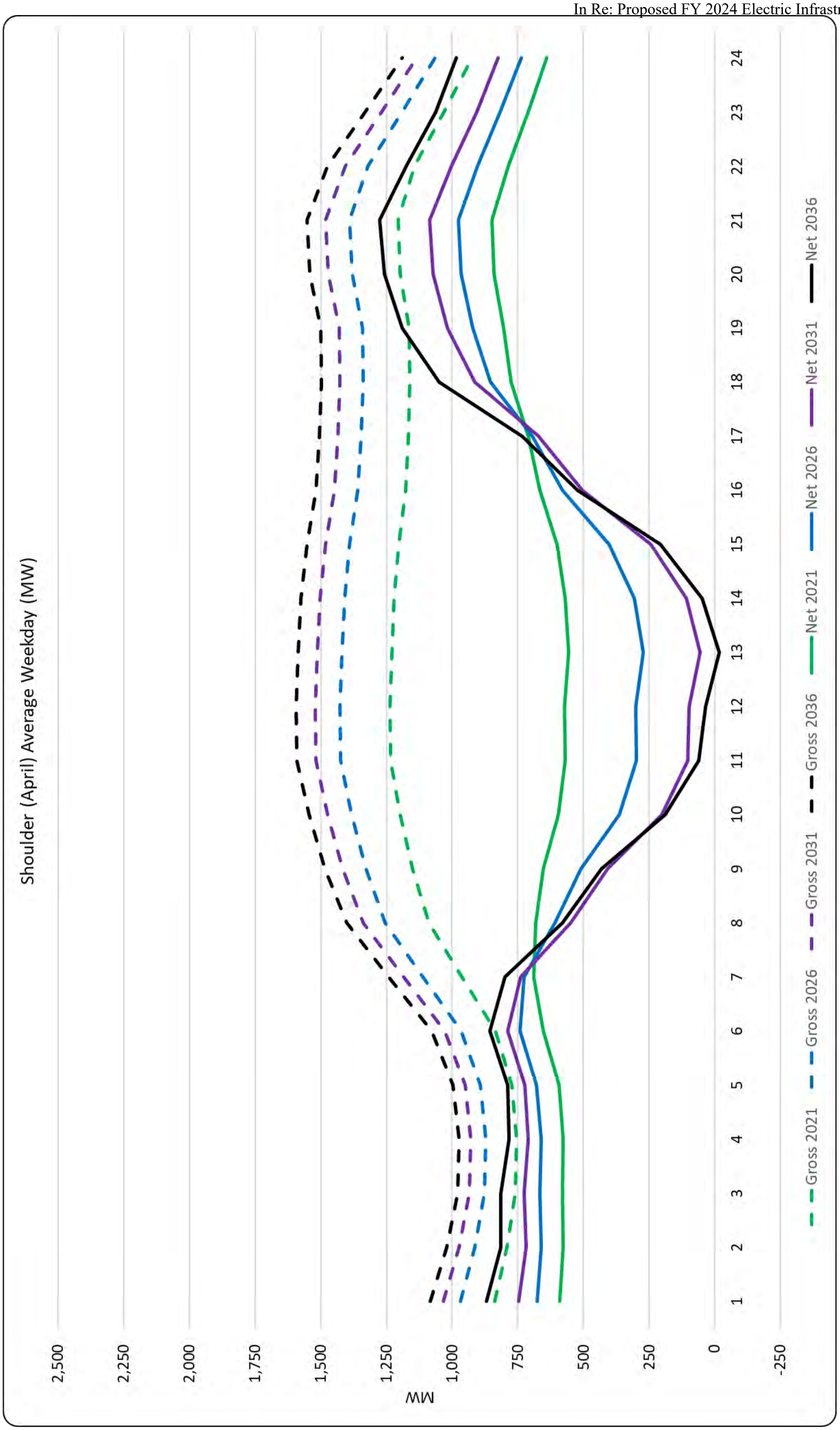
(for Base Case)

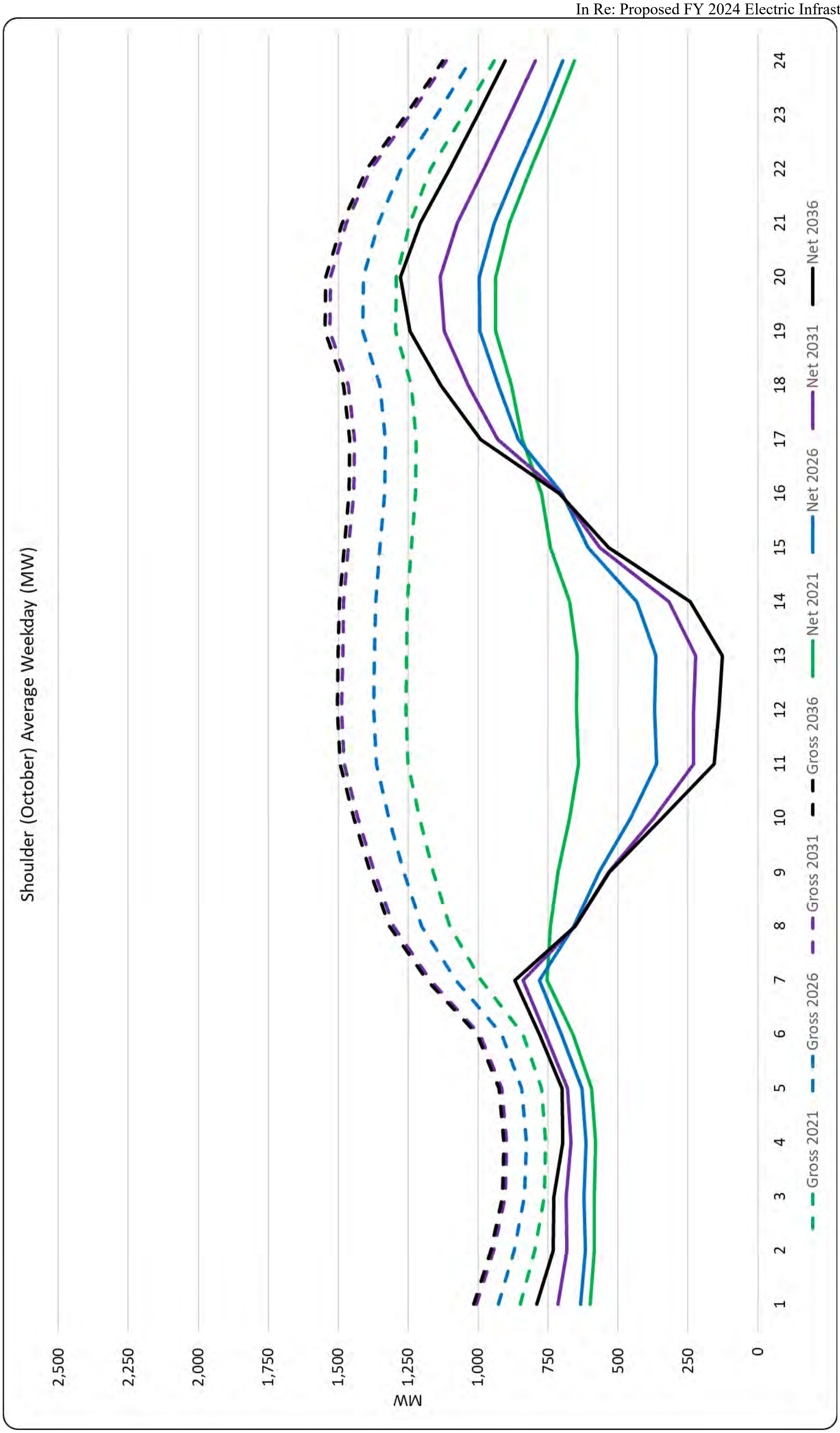

NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
3,000
2,500
2,000
1,500
1,000
500
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2022
Gross - 2022
Net - 2026
Gross - 2026
Net - 2031
Gross - 2031
Net- 2036
Gross - 2036

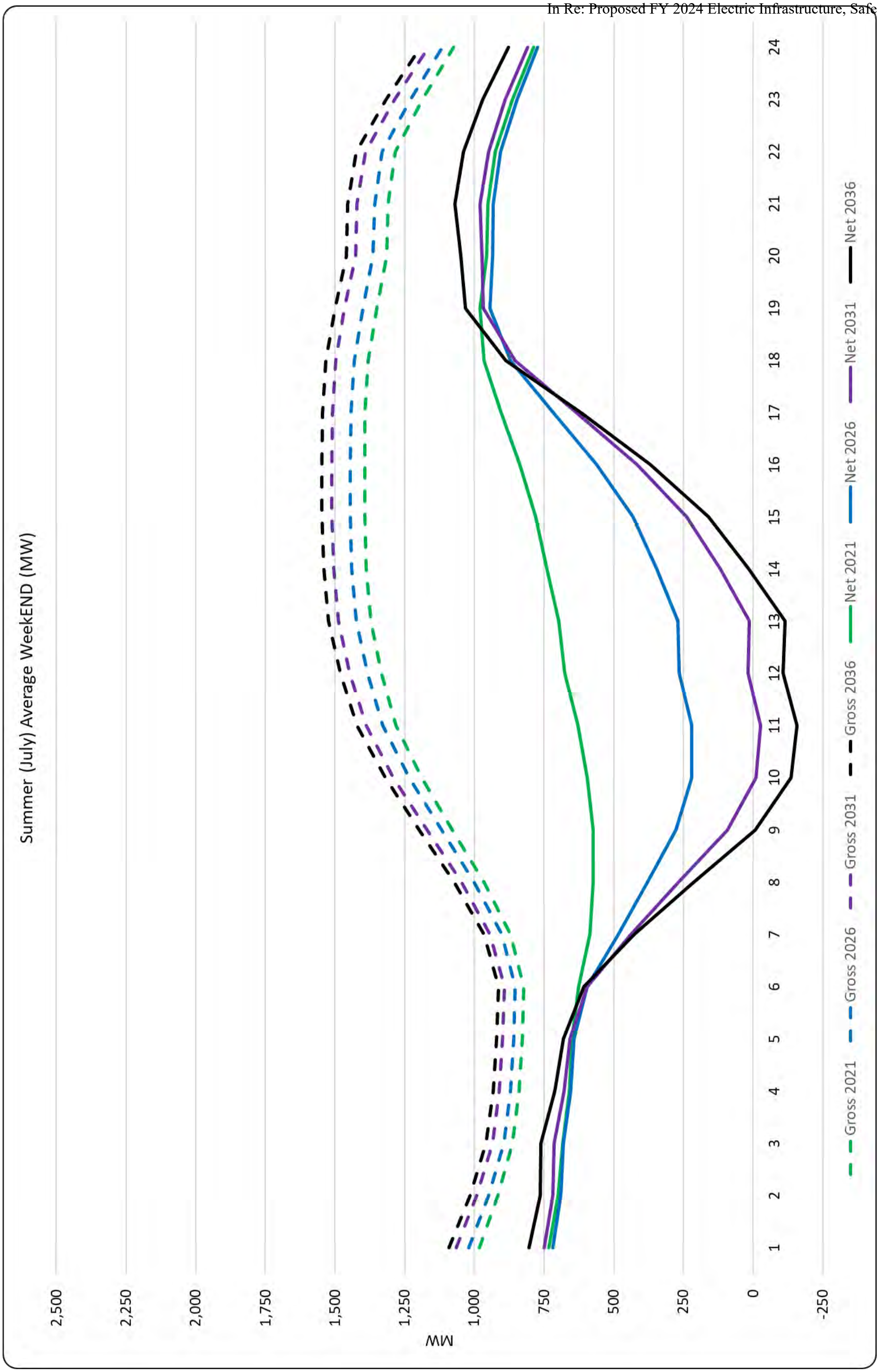

NECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
2,000
1,500
1,000
500
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2021
Net - 2025
Net - 2030
Net - 2035
Gross - 2021
Gross - 2025
Gross - 2030
Gross - 2035

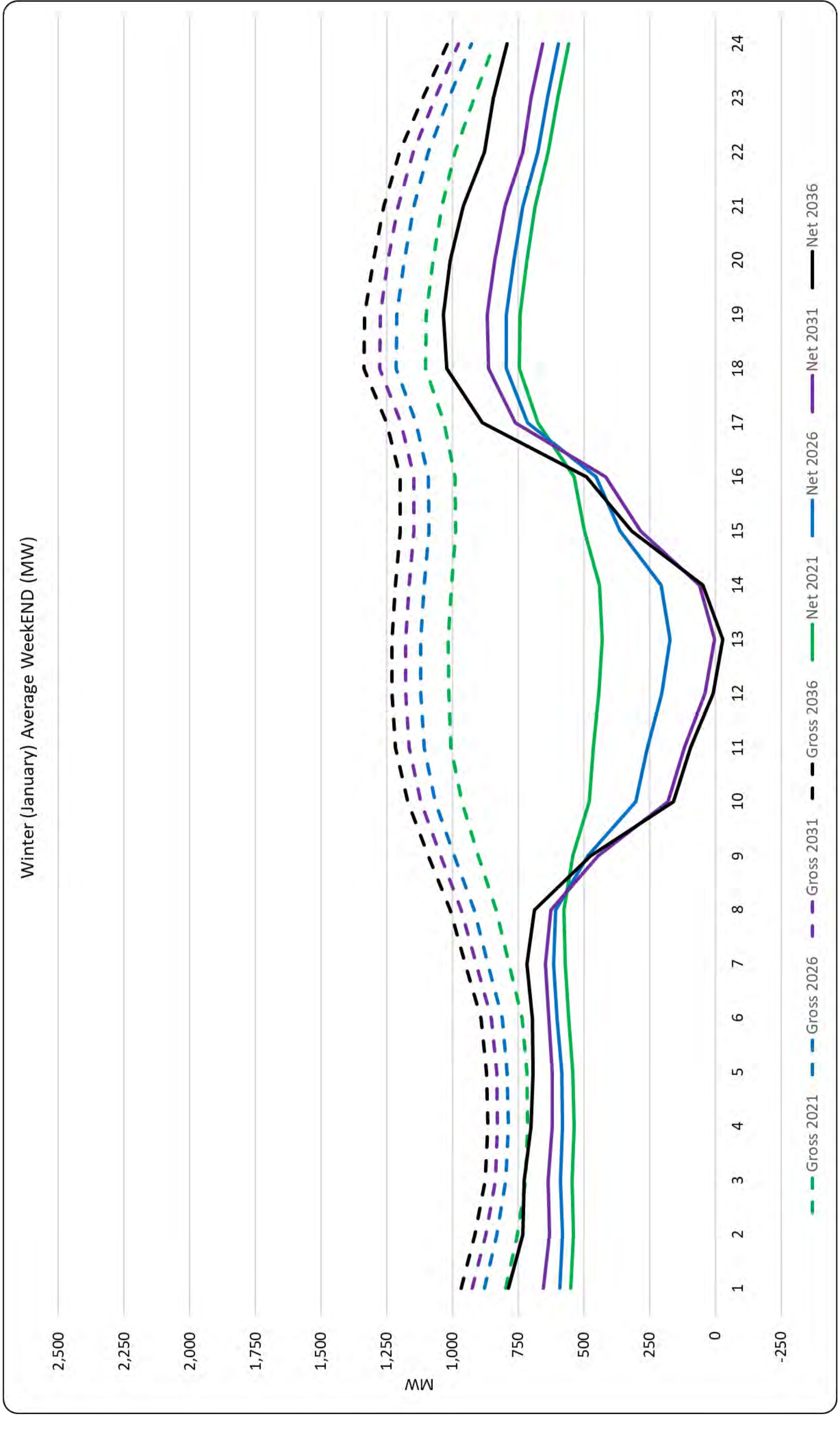

Summer (July) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036

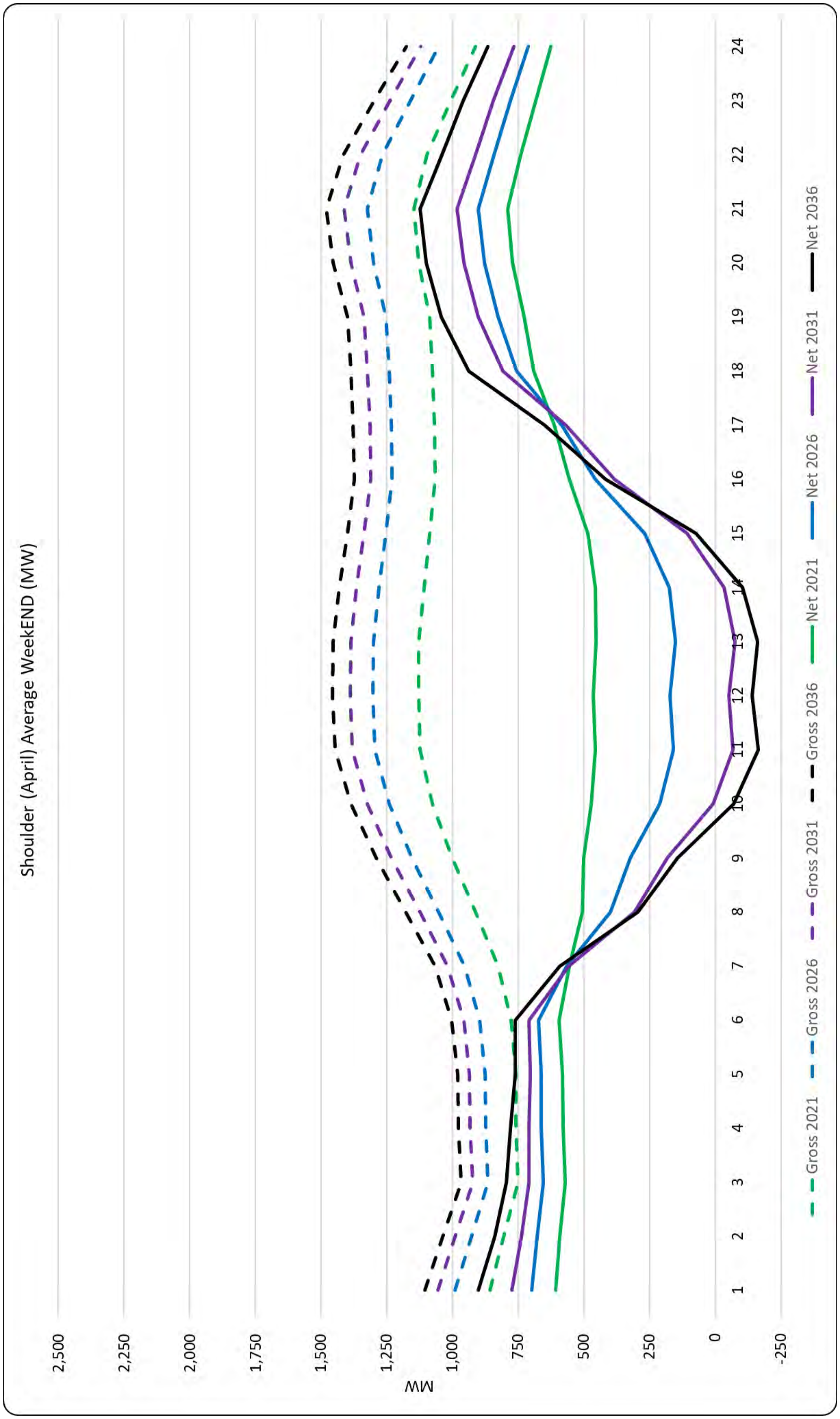

Winter (January) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036

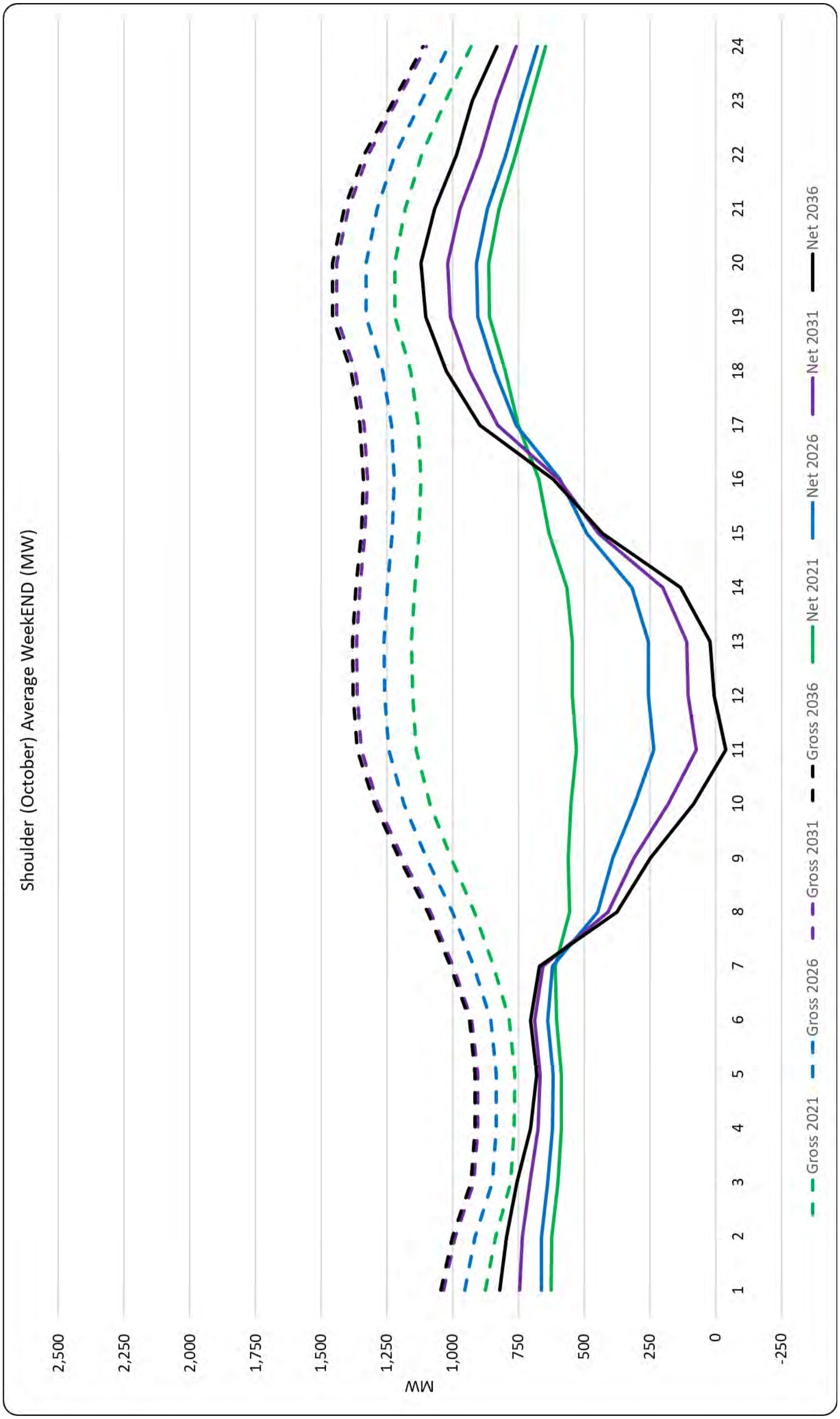

Shoulder (April) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036


Shoulder (October) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036


Summer (July) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036


Winter (January) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036

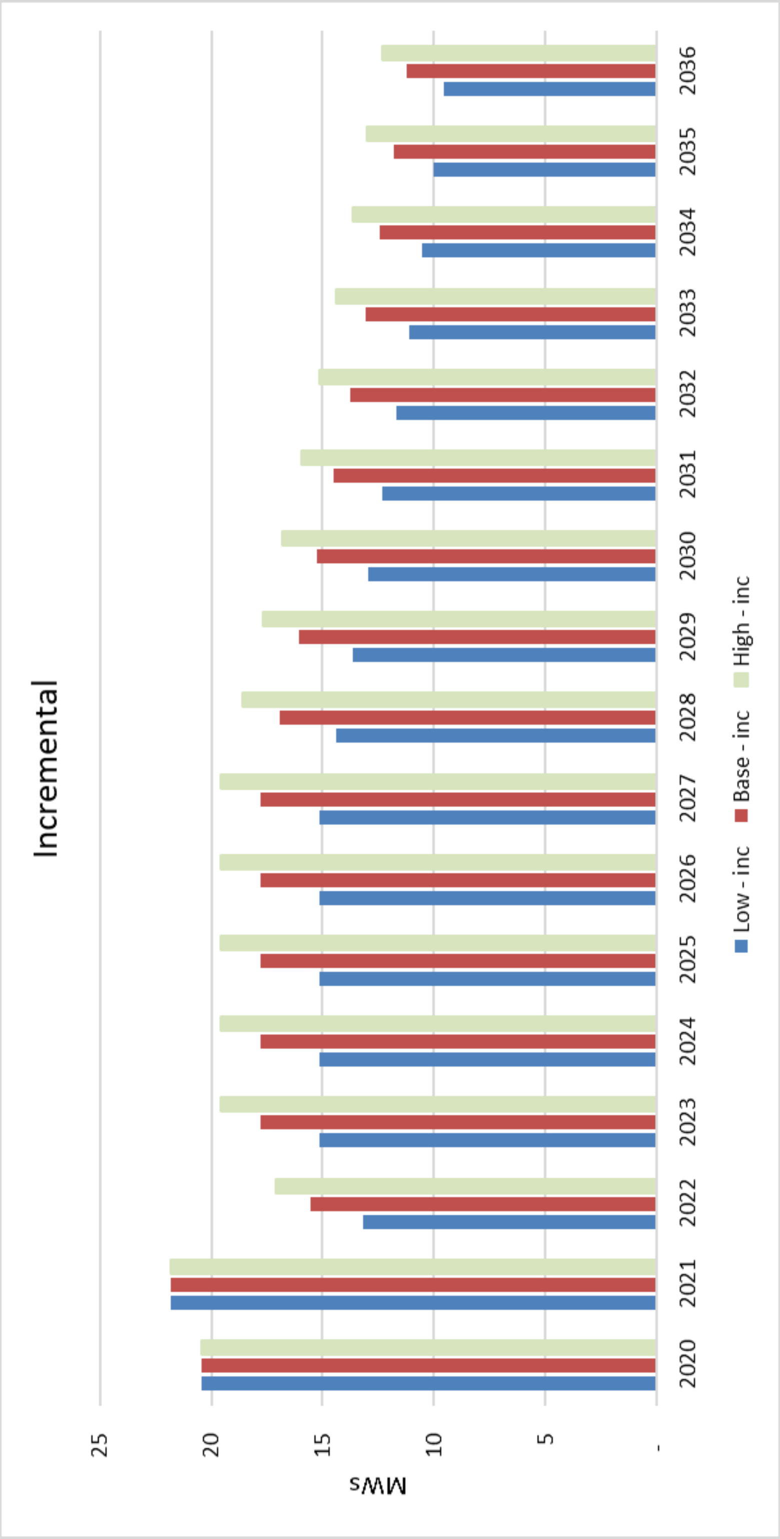

Shoulder (April) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036

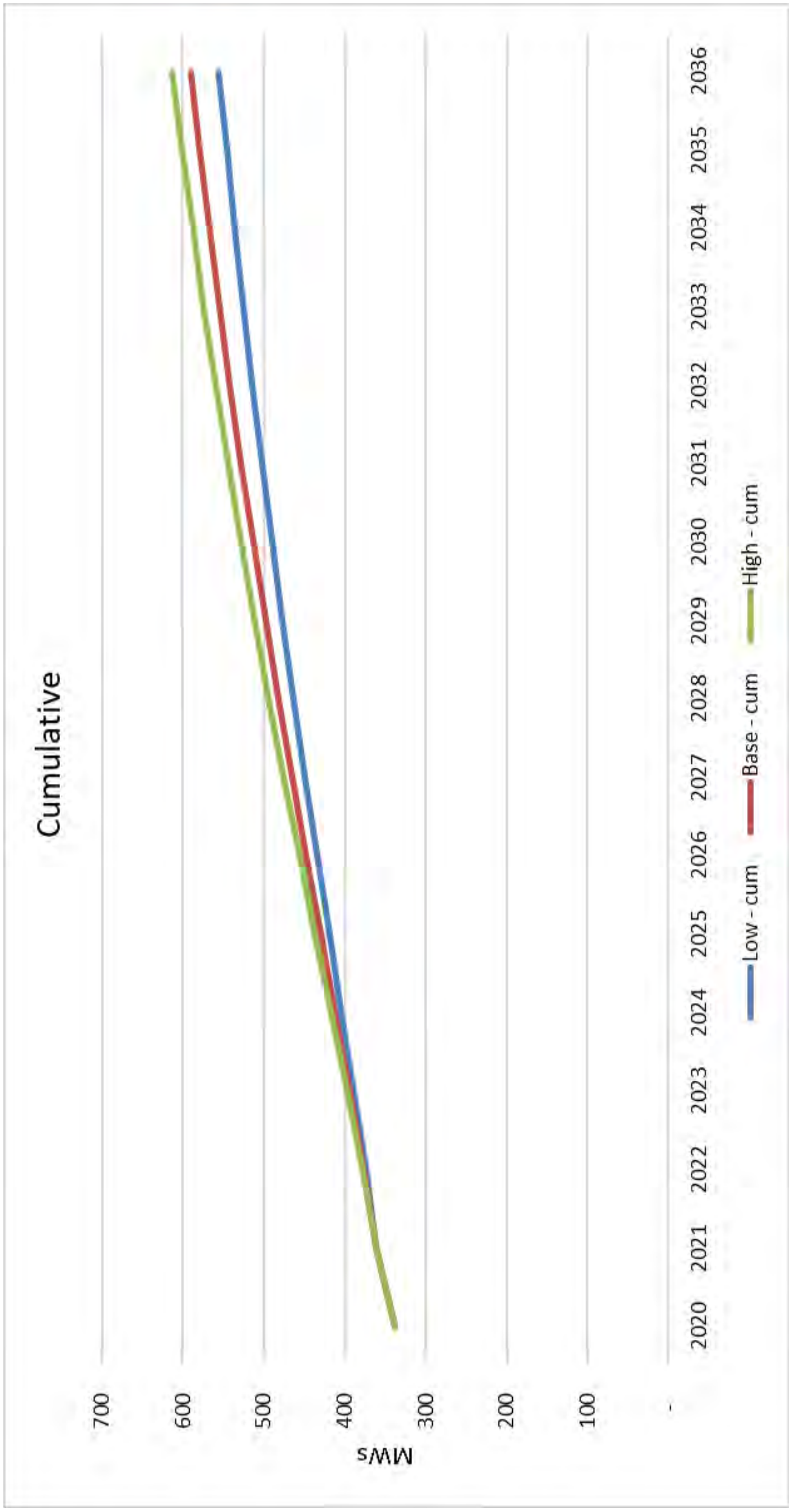

Shoulder (October) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2021
Gross 2026
Gross 2031
Gross 2036
Net 2021
Net 2026
Net 2031
Net 2036

Appendix D: DER Scenarios Inputs

Energy Efficiency (NECO)

Summer Peak MWs						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2020	20	339	20	339	20	339
2021	22	361	22	361	22	361
2022	13	374	16	376	17	378
2023	15	389	18	394	20	397
2024	15	404	18	412	20	417
2025	15	419	18	430	20	436
2026	15	434	18	447	20	456
2027	15	450	18	465	20	476
2028	14	464	17	482	19	494
2029	14	478	16	498	18	512
2030	13	491	15	513	17	529
2031	12	503	14	528	16	545
2032	12	515	14	542	15	560
2033	11	526	13	555	14	574
2034	11	536	12	567	14	588
2035	10	546	12	579	13	601
2036	10	556	11	590	12	613

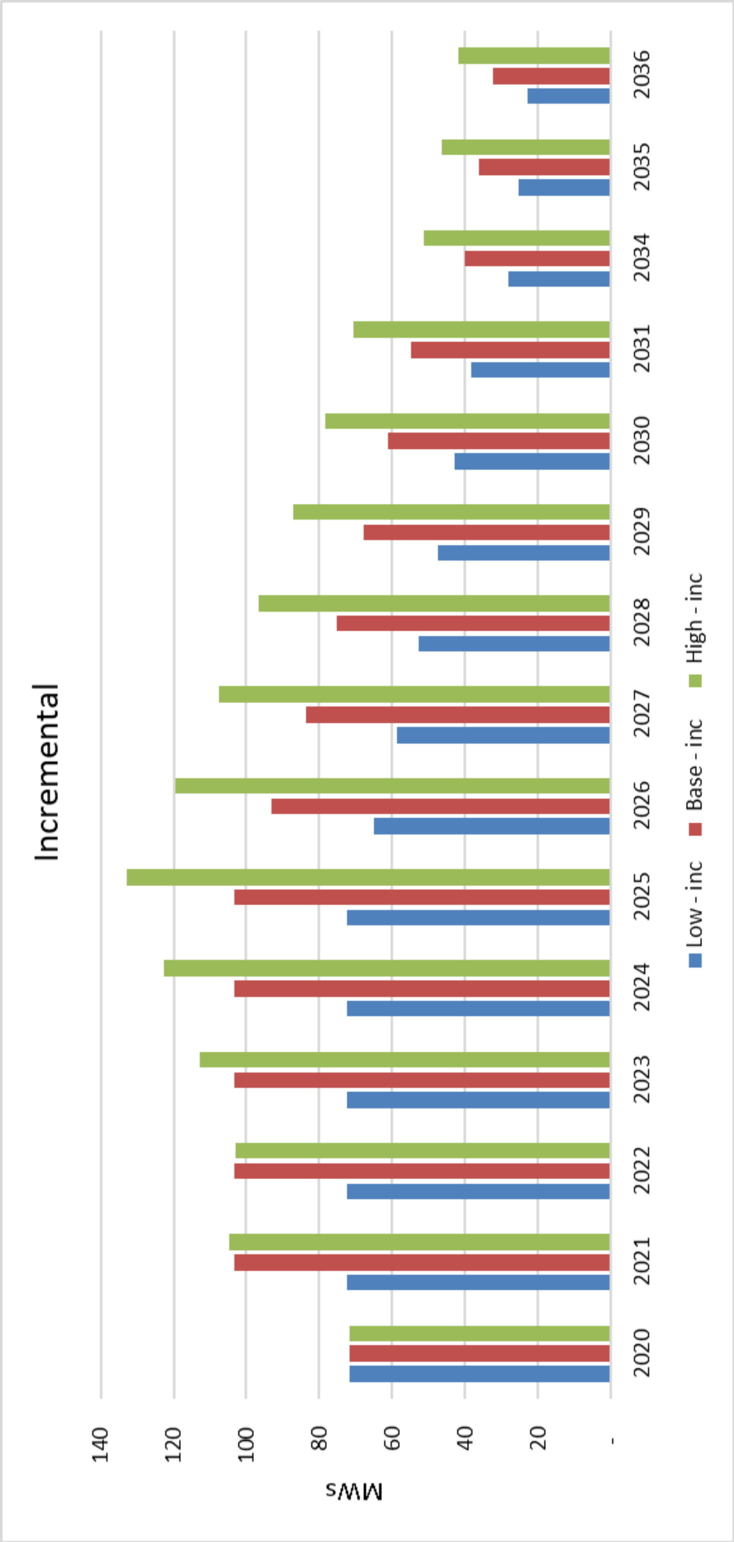

Incremental
MWs
25
20
15
10
5
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - inc
Base - inc
High - inc

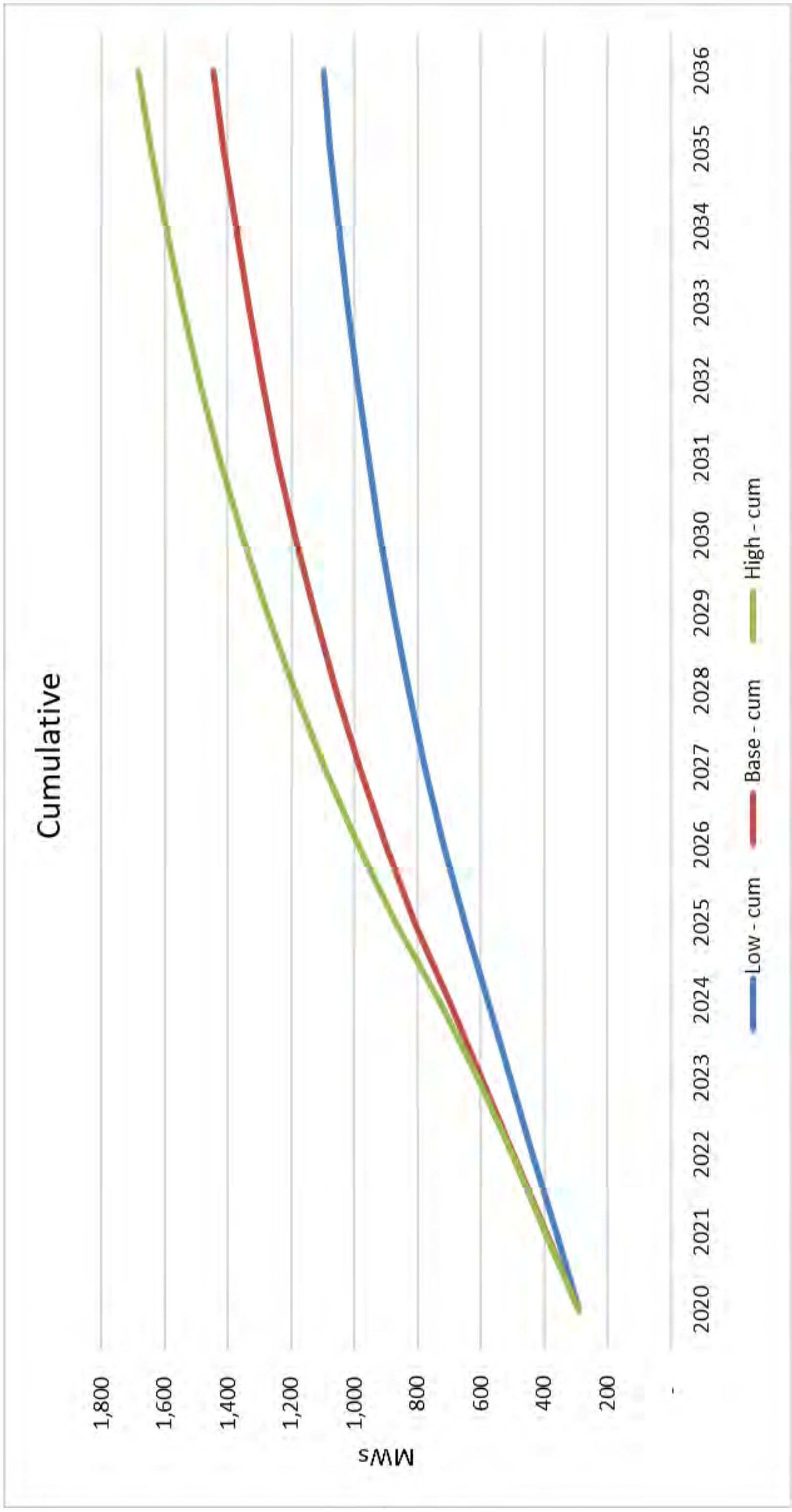

Cumulative
MWs
700
600
500
400
300
200
100
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - cum
Base - cum
High - cum

Solar – PV (NECO)
Installed Nameplate MWs

Connected Nameplated (MW)

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	72	291	72	291	72	291
2021	72	363	103	394	105	396
2022	72	436	103	498	103	499
2023	72	508	103	601	113	612
2024	72	581	103	704	123	734
2025	72	653	103	808	133	867
2026	65	718	93	901	119	987
2027	59	777	84	984	107	1,094
2028	53	829	75	1,060	97	1,191
2029	47	877	68	1,128	87	1,278
2030	43	920	61	1,189	78	1,356
2031	38	958	55	1,244	71	1,427
2032	35	993	49	1,293	63	1,490
2033	31	1,024	44	1,337	57	1,547
2034	28	1,052	40	1,377	51	1,599
2035	25	1,077	36	1,414	46	1,645
2036	23	1,100	32	1,446	42	1,687


Incremental
MWs
140
120
100
80
60
40
20
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2034
2035
2036
Low - inc
Base - inc
High - inc


Cumulative
MWs
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - cum
Base - cum
High - cum

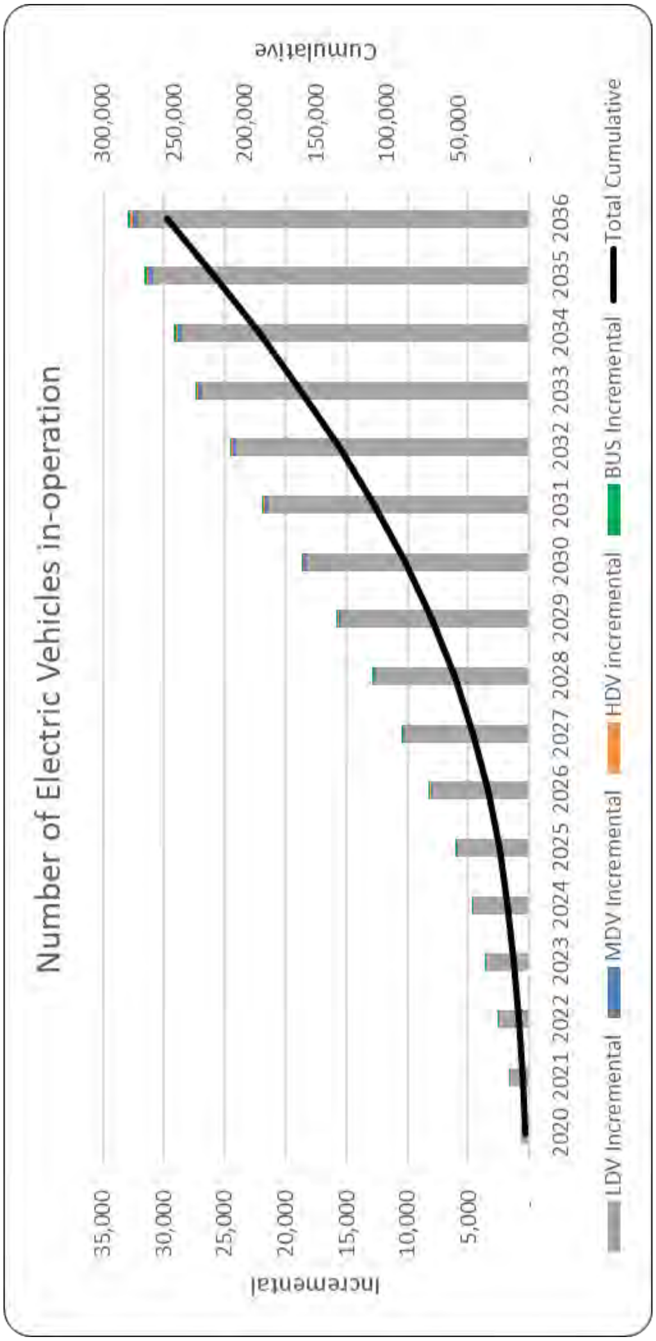
Electric Vehicles (NECO)

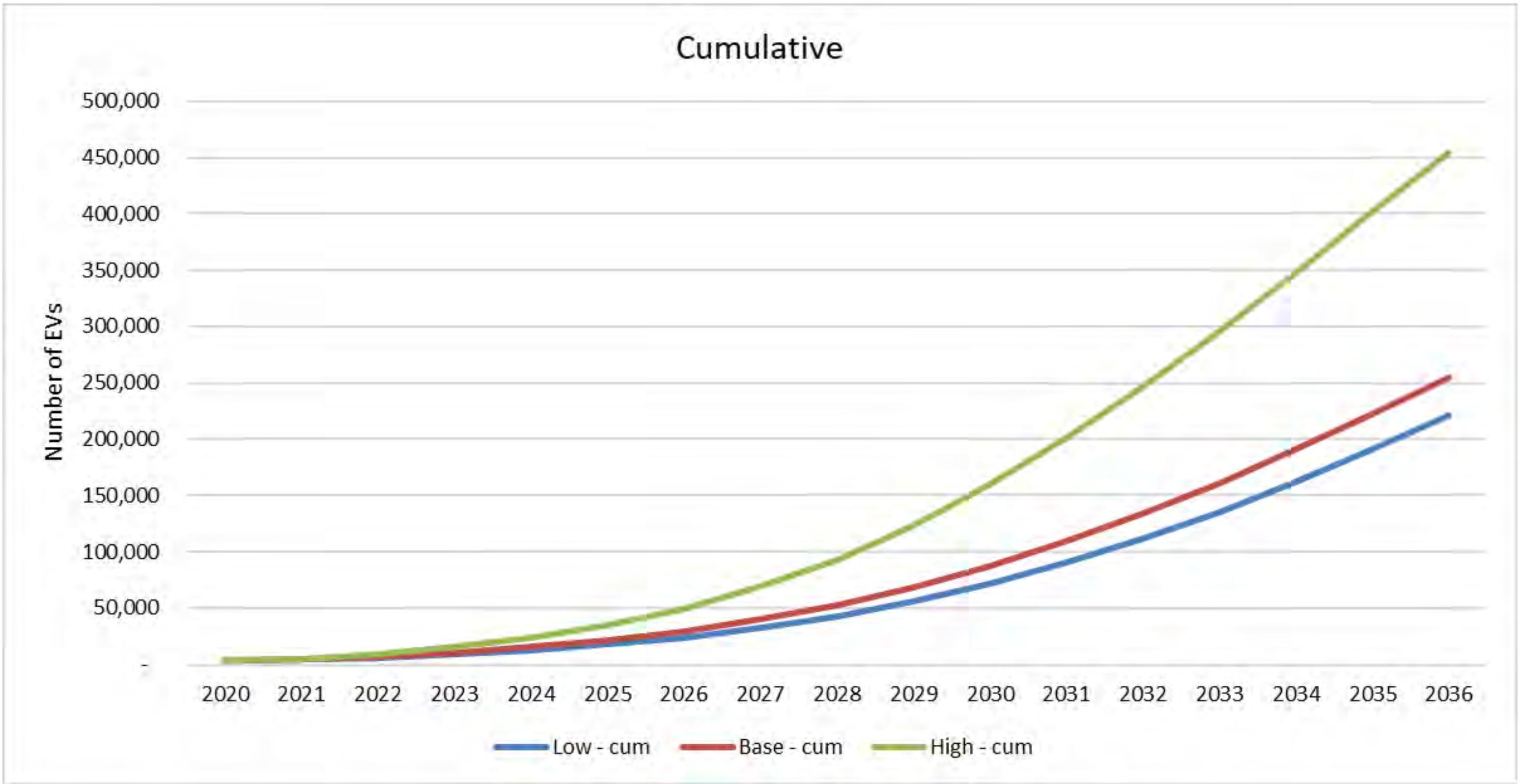
Number of Vehicles

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	708	2,946	708	2,946	708	2,946
2021	1,173	4,119	1,587	4,533	1,734	4,680
2022	1,809	5,927	2,507	7,039	3,971	8,651
2023	2,776	8,703	3,566	10,605	6,503	15,154
2024	3,845	12,548	4,683	15,288	8,484	23,638
2025	5,007	17,555	6,017	21,305	10,882	34,521
2026	6,428	23,983	8,189	29,494	14,993	49,514
2027	8,508	32,491	10,468	39,962	19,398	68,912
2028	10,490	42,981	12,893	52,855	24,245	93,157
2029	12,974	55,955	15,768	68,623	30,008	123,164
2030	15,627	71,582	18,698	87,321	36,026	159,190
2031	18,815	90,397	21,920	109,241	41,755	200,945
2032	21,228	111,625	24,572	133,813	46,066	247,011
2033	23,966	135,590	27,454	161,266	49,329	296,340
2034	26,071	161,662	29,191	190,458	51,167	347,507
2035	28,862	190,524	31,588	222,046	54,241	401,749
2036	31,124	221,648	32,935	254,981	53,380	455,128

Number of Light-duty Vehicles

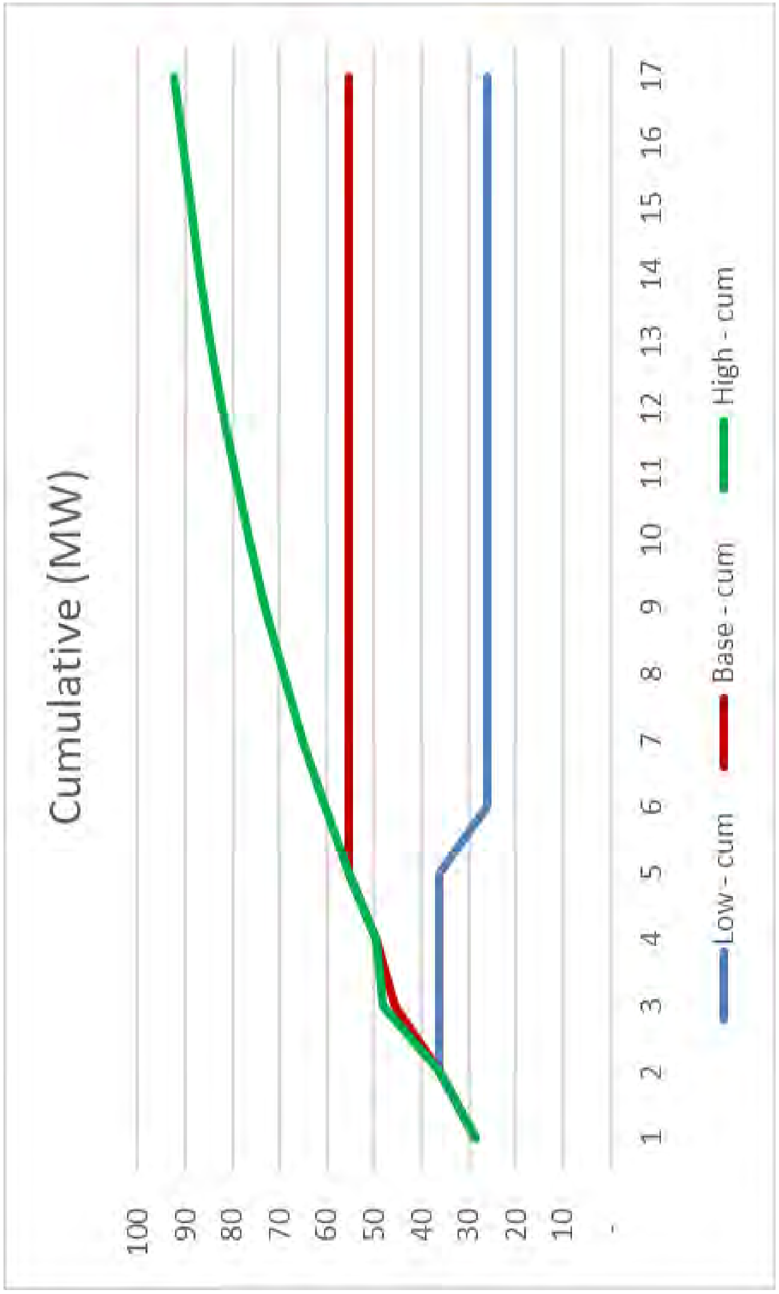
Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2,020	708	2,946	708	2,946	708	2,946
2,021	1,156	4,102	1,570	4,516	1,570	4,516
2,022	1,774	5,876	2,472	6,988	3,861	8,377
2,023	2,717	8,593	3,507	10,495	6,353	14,730
2,024	3,753	12,346	4,591	15,086	8,300	23,030
2,025	4,873	17,219	5,883	20,969	10,654	33,684
2,026	6,253	23,472	8,014	28,983	14,625	48,309
2,027	8,283	31,755	10,243	39,226	18,882	67,191
2,028	10,207	41,962	12,610	51,836	23,581	90,772
2,029	12,627	54,589	15,421	67,257	29,155	119,927
2,030	15,212	69,801	18,283	85,540	35,033	154,960
2,031	18,334	88,135	21,439	106,979	40,666	195,626
2,032	20,680	108,815	24,024	131,003	44,881	240,507
2,033	23,354	132,169	26,842	157,845	48,048	288,555
2,034	25,399	157,568	28,519	186,364	49,807	338,362
2,035	28,134	185,702	30,860	217,224	52,814	391,176
2,036	30,345	216,047	32,156	249,380	51,884	443,060


Number of Electric Vehicles in-operation
Incremental
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
Cumulative
300,000
250,000
200,000
150,000
100,000
50,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
LDV Incremental
MDV Incremental
HDV incremental
BUS Incremental
Total Cumulative


Cumulative
Number of EVs
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - cum
Base - cum
High - cum

Demand Response (NECO)

Year	Low - cum	Base - cum	High - cum
2020	29	29	29
2021	36	36	36
2022	36	46	48
2023	36	50	50
2024	36	55	55
2025	26	55	61
2026	26	55	65
2027	26	55	69
2028	26	55	73
2029	26	55	76
2030	26	55	79
2031	26	55	82
2032	26	55	85
2033	26	55	87
2034	26	55	89
2035	26	55	91
2036	26	55	92


Cumulative (MW)
100
90
80
70
60
50
40
30
20
10
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
Low - cum
Base - cum
High - cum

Energy Storage (NECO)[13]

Year	Base - inc	Base - cum
2020	0.53	0.8
2021	0.52	1.4
2022	0.52	1.9
2023	0.52	2.4
2024	0.52	2.9
2025	0.52	3.4
2026	0.52	4.0
2027	0.52	4.5
2028	0.52	5.0
2029	0.52	5.5
2030	0.52	6.0
2031	0.52	6.6
2032	0.52	7.1
2033	0.52	7.6
2034	0.52	8.1
2035	0.52	8.6
2036	0.52	9.1

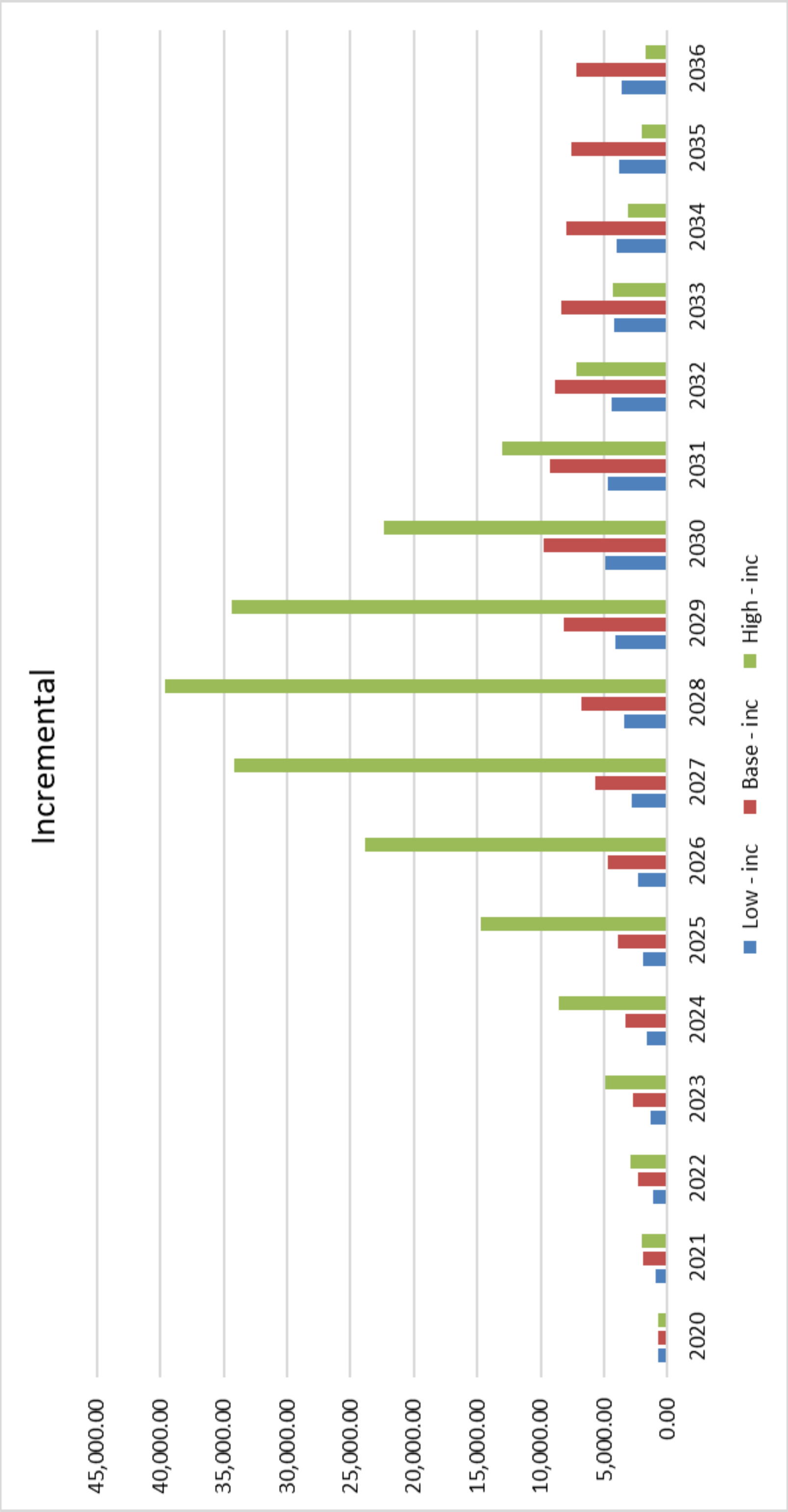
---

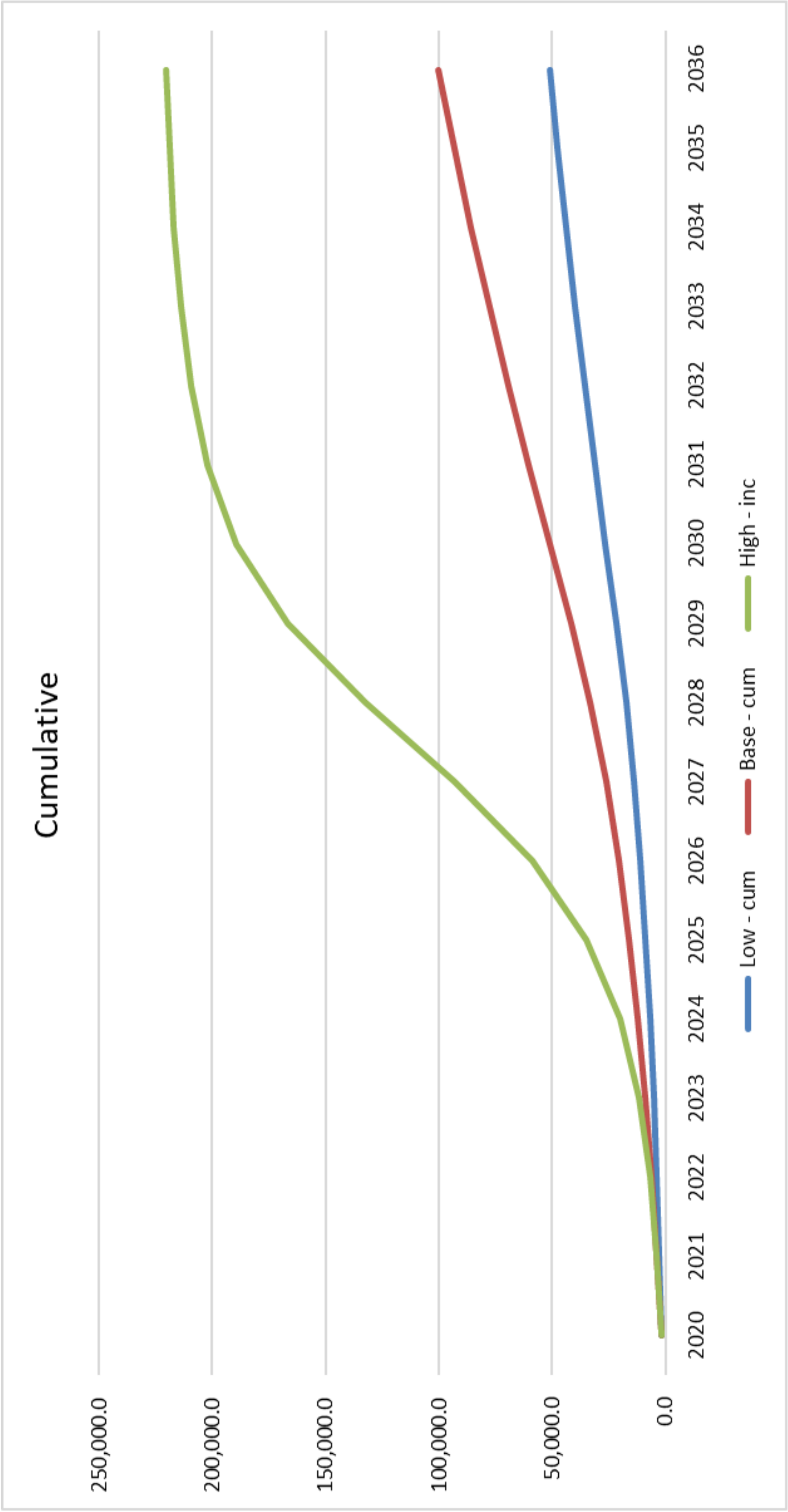
[13] Another small amount of storage is being captured in the Company's demand response program in Rhode Island.

Electric Heat Pumps (NECO)

Number of Electric Heat Pumps

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	760	1,848	760	1,848	760	1,848
2021	952	2,800	1,904	3,752	2,000	3,848
2022	1,150	3,950	2,300	6,052	2,908	6,756
2023	1,350	5,300	2,700	8,752	4,888	11,643
2024	1,650	6,950	3,300	12,052	8,585	20,228
2025	1,950	8,900	3,900	15,952	14,713	34,941
2026	2,350	11,250	4,700	20,652	23,814	58,755
2027	2,850	14,100	5,700	26,352	34,170	92,925
2028	3,400	17,500	6,800	33,152	39,616	132,542
2029	4,100	21,600	8,200	41,352	34,390	166,932
2030	4,900	26,500	9,800	51,152	22,357	189,288
2031	4,655	31,155	9,310	60,462	13,013	202,301
2032	4,422	35,577	8,845	69,307	7,143	209,445
2033	4,201	39,778	8,402	77,709	4,345	213,789
2034	3,991	43,769	7,982	85,691	3,162	216,951
2035	3,792	47,561	7,583	93,274	1,982	218,934
2036	3,602	51,163	7,204	100,478	1,725	220,659


Incremental
45,000.00
40,000.00
35,000.00
30,000.00
25,000.00
20,000.00
15,000.00
10,000.00
5,000.00
0.00
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - inc
Base - inc
High - inc


Cumulative
250,000.0
200,000.0
150,000.0
100,000.0
50,000.0
0.0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Low - cum
Base - cum
High - inc

Appendix E: DER Scenarios Development

- Persistent and non-persistent savings are differentiated to correctly account for the accumulation of claimable savings over time. Non-persistent savings from behavioral programs like the home energy report do not accumulate over time. Home energy report savings are assumed to remain at the same level for each year of the planning cycle across all three cases. Savings from persistent programs do accumulate over time (i.e. lighting programs).
- All reported and planned savings values in the forecast data are in net, program-claimable annual savings terms.
- Any savings from heat pumps and demand response programs are removed as they are projected separately.

Base

- The Company three-year plan from the Subject Matter Experts (SMEs) is used for the short-term through 2023.
- Post-2024 until 2028, the incremental value of persistent EE savings is held constant at 2023 levels. In 2028, persistent savings are still expected to continue to grow but at a slower rate each year. The growth rate slows by 5% annually to account for saturation of claimable savings.

High

- The incremental persistent EE savings in the high case is set at 110% of the base case.
- In 2028, persistent savings are still expected to continue to grow but at a slower rate each year. The growth rate slows by 5% annually to account for saturation of claimable savings.

Low

- The incremental persistent EE savings in the low case is set at 85% of the base case.
- In 2028, persistent savings are still expected to continue to grow but at a slower rate each year. The growth rate slows by 5% annually to account for saturation of claimable savings.

Solar-PV

Base

- The 2021 prediction is based on the 2021 Year-to-Date connected projects, the SME expectations from projects in the queue, and the status/stages of the projects in the queue. The same level of new installations is assumed till the year of 2025.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

High

- The near-term (2021-2025) predictions on the incremental installation are from the high scenario of our Market Fundamental team.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Low

- The low case for PV assumes remaining the same level of 2020's incremental installation till 2025.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Electric Vehicles

Light-duty Vehicles

Base

- The base case is developed from Bloomberg's 2021 Long-term Electric Vehicle Outlook (BNEF-2021). The EV sales share of light-duty vehicle (LDV) sales is assumed to follow BNEF-2021 estimates and vehicle scrap is also assumed based on BNEF-2021's estimates to develop the net EV in-operation numbers. In this case, the zero-emission vehicle sales share of LDV sales is assumed to achieve 31% by 2030 and 59% by 2035.

High

- The high case assumes an accelerated full-electrification scenario in which the zero-emission vehicle sales share of LDV sales is assumed to achieve 64% by 2030 and 100% by 2035. It also aligns with BNEF-2021's "Net Zero" scenario and California drafted ACC-II regulation.

Low

- The low case is a moderate transportation electrification case developed from BNEF-2021. In this case, the zero-emission vehicle sales share of LDV sales is assumed to reach 25% by 2030 and 54% by 2035.

Medium-duty and Heavy-duty Vehicles, and E-buses

The adoptions of medium-duty EV (MDEV) and heavy- duty EV (HDEV) and E-buses are based on BNEF-2021 estimates and the MOU policy targets. Two cases were developed for the adoption's forecasts of these electric vehicle types. The base case is more of a market-driven case of adopting MDEV, HDEV, and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 16%, 17%, and 26% of MDV, HDV, and buses, respectively, by the end of the load forecast horizon. The high case is an accelerated electrification scenario for medium- and heavy-duty vehicles and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 38%, 20%, and 63% of MDV, HDV, and buses, respectively, by the end of the load forecast horizon.

Overall, the base light-duty EV case and the base medium- and heavy-duty EVs and E-buses case is considered as the base EV case. The high light-duty EV case and the high medium- and heavy-duty EVs and E-buses case is considered as the low EV case. The low light-duty EV case and the base medium- and heavy-duty EVs and E-buses case is considered as the low EV case.

Demand Response

Base Case:
For the short term (i.e. until 2024), the approved Company targets from the SME Program Administrator for DR is used as the projection. Post year 2024, no additional incremental MW are added. It is assumed that the program's market potential is at its maximum and the projections are held constant through year 2036.

High Case:
The high case is a continued incremental growth following the approved program years. Beginning in year 2025, the prior years' annual incremental level is continued, however, at a smaller amount each year forward to reflect a level of saturation. This value is set at 15% less incremental new participation each year versus the prior year.

Low Case:
For the short-term, the 2021 level is held constant through year 2024. Then post 2024, there is assumed to be a discontinuation of the Company incentivized program. Since DR needs to be implemented, dispatched, and paid for continuously unlike other DER programs which once installed persist for many years and still garner savings, DR impacts can end once funding is discontinued. Thus, post year 2024, it is assumed that residential type DR would move to zero. However, for commercial related programs, there may still be sufficient non-Company market pricing incentives for some customers to continue to implement DR. It is assumed that post 2024, a level of 60% of the 2024 commercial level continues into the future planning horizon.

Energy Storage

There is currently no explicit state energy storage policy targets in RI, nor any Company run programs to promote this DER. In year 2020 about 0.53 MW of storage was installed. For the base case this same level of about half MW per year is continued into the future. No low or high cases are included. It is noted that there is a small amount of storage being captured in the Company's Demand Response program in RI.

Electric Heat Pumps

Base Case:

This based on the Company's pro rata share of the ISO-NE heat electrification forecast, which is a projection for residential heat pumps installations in the state. Commercial heat pumps are not currently incentivized. The ISO-NE forecast ends in 2030 and is extended to 2036 by assuming 5% annual decrease from 2030 levels. This approach provides for about a 12% penetration of all homes by year 2030, and about 23% by year 2036.

High Case:

The high case is based on achieving residential penetration of about a 35% by 2030 and 47% by 2036, which is similar levels seen in Massachusetts high case. For commercial establishments, the penetration levels are 7% in 2030 and 25% in 2036. An "S-Curve function" is used to reach these levels of penetration in Rhode Island.

Low Case:

The low case is set at half the base case. This approach provides for about a 6% penetration of all residential homes by year 2030, and about 12% by year 2036.

Appendix F: Power Supply Areas (PSAs)

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) — **after EE, PV, EV, EH, DR, and ES impacts**

			2021 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2022	2023	2024	2025	2026	'22 to '26	'27 to '31	'32 to '36
RI	Blackstone Valley	RI	95.1%	104.2%	106.8%	0.3	0.1	(0.1)	0.1	(0.5)	(0.0)	0.4	0.5
RI	Newport	RI	95.1%	104.2%	106.8%	0.9	0.7	0.3	0.5	(0.1)	0.5	0.7	0.7
RI	Providence	RI	95.1%	104.2%	106.8%	0.6	0.4	0.1	0.3	(0.3)	0.2	0.5	0.6
RI	Western Narraganset	RI	95.1%	104.2%	106.8%	1.1	0.8	0.5	0.7	0.0	0.6	0.8	0.7

Year One Weather-Adjustment & Multi-Year Annual Growth (Summer) — **after EE, EV, DR, and ES impacts, but before PV reductions**

			2021 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2022	2023	2024	2025	2026	'22 to '26	'27 to '31	'32 to '36
RI	Blackstone Valley	RI	95.1%	104.2%	106.8%	0.9	0.7	0.4	0.7	0.1	0.5	0.8	0.7
RI	Newport	RI	95.1%	104.2%	106.8%	1.5	1.2	0.9	1.1	0.4	1.0	1.0	0.8
RI	Providence	RI	95.1%	104.2%	106.8%	1.2	1.0	0.7	0.9	0.2	0.8	0.9	0.7
RI	Western Narraganset	RI	95.1%	104.2%	106.8%	1.7	1.4	1.0	1.2	0.6	1.2	1.2	0.9

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER) — **after EE, PV, EV, and EH impacts**

			2020/21 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 10/90	for 05/95	2021	2022	2023	2024	2025	'21 to '25	'26 to '30	'31 to '3
RI	Blackstone Valley	RI	98.7%	103.5%	104.8%	1.4	2.0	1.5	1.5	1.2	1.5	2.2	3.1
RI	Newport	RI	98.7%	103.5%	104.8%	2.1	2.7	2.0	2.0	1.6	2.1	2.5	3.3
RI	Providence	RI	98.7%	103.5%	104.8%	1.8	2.4	1.7	1.7	1.4	1.8	2.3	3.2
RI	Western Narraganset	RI	98.7%	103.5%	104.8%	2.2	2.8	2.2	2.1	1.8	2.2	2.6	3.4

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents can be applied to the current winter peaks to determine what the growth for each area is.

Division 1-15

Request:

On pages 10-11, the Company explains that "(a) base case is developed for each DER item using its own recent trend, approved programs, and studies as appropriate. The combination of the base cases from these DER items is considered as the base DER scenario and is considered as the most probable scenario at this time. Scenarios of varying levels and types of DER adoption are also developed to provide additional insights into what loads could look like under different scenarios. System Planning used the load with base DER scenario projections from the most recent load forecast for System Capacity and Area Planning Reviews as well as the Grid Modernization Plan."

a. Is the Company relying on a single load forecast for Area Planning Reviews and the Grid Modernization Plan? Why or why not?
b. If multiple forecasts are utilized, explain in detail the difference in the models. Provide all criteria, assumptions and workpapers used to develop forecasts, with underlying data in executable format.

Response:

a. Yes, the Company starts with the same load forecast base scenarios for Area Planning Reviews and the Grid Modernization Plan. The Grid Modernization Plan forecast, however, needed to be projected beyond the typical 15 years to 2050 to sufficiently analyze system issues that may arise in meeting Rhode Island's Act on Climate requirements. The same forecast is used to provide consistency between the various efforts.

b. Attachment DIV 1-15 shows how the existing forecast was projected to 2050.

NECO

SUMMER 50/50 Peaks (MW) (before & after DERs)

			SYSTEM PEAK								DER IMPACTS								% of reconstituted peaks						
		Calendar Year	Reconstituted Load MW PreDER	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE-Orig	EE MW	PV	EV	DR	ES	EH	DER	EE %	PV %	EV %	DR %	ES %	EH %	DER %
	-	2005	1,826	1,799	1,826	1,826	1,826	1,826	1,826	1,799	(27)	27	(0)	0.0	0.0	0.0	0.0	(27)	-1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	-1.5%
	-	2006	1,865	1,829	1,865	1,865	1,865	1,865	1,865	1,829	(37)	37	(0)	0.0	0.0	0.0	0.0	(37)	-2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-2.0%
	-	2007	1,926	1,880	1,926	1,926	1,926	1,926	1,926	1,879	(47)	47	(0)	0.0	0.0	0.0	0.0	(47)	-2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	-2.4%
	-	2008	1,900	1,843	1,900	1,900	1,900	1,900	1,900	1,843	(57)	57	(0)	0.0	0.0	0.0	0.0	(57)	-3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.0%
	-	2009	1,916	1,846	1,915	1,916	1,916	1,916	1,916	1,845	(70)	70	(0)	0.0	0.0	0.0	0.0	(71)	-3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.7%
	-	2010	1,913	1,829	1,913	1,913	1,913	1,913	1,913	1,829	(84)	84	(1)	0.0	0.0	0.0	0.0	(84)	-4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.4%
	-	2011	1,944	1,848	1,944	1,944	1,944	1,944	1,944	1,847	(96)	96	(1)	0.0	0.0	0.0	0.0	(97)	-5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.0%
	-	2012	1,964	1,851	1,963	1,964	1,964	1,964	1,964	1,850	(113)	113	(1)	0.0	0.0	0.0	0.0	(114)	-5.7%	-0.1%	0.0%	0.0%	0.0%	0.0%	-5.8%
	-	2013	1,989	1,852	1,984	1,989	1,989	1,989	1,989	1,847	(137)	137	(5)	0.1	0.0	0.0	0.0	(142)	-6.9%	-0.3%	0.0%	0.0%	0.0%	0.0%	-7.1%
	-	2014	2,018	1,848	2,011	2,018	2,018	2,018	2,018	1,841	(170)	170	(7)	0.1	0.0	0.0	0.0	(177)	-8.4%	-0.3%	0.0%	0.0%	0.0%	0.0%	-8.8%
	-	2015	2,096	1,894	2,084	2,096	2,096	2,096	2,096	1,882	(202)	202	(12)	0.2	0.0	0.0	0.0	(214)	-9.6%	-0.6%	0.0%	0.0%	0.0%	0.0%	-10.2%
	-	2016	2,051	1,821	2,038	2,051	2,051	2,051	2,051	1,808	(230)	230	(14)	0.3	(0.0)	0.0	0.0	(243)	-11.2%	-0.7%	0.0%	0.0%	0.0%	0.0%	-11.9%
	-	2017	2,037	1,781	2,014	2,037	2,032	2,037	2,037	1,754	(256)	256	(23)	0.4	(5.0)	0.0	0.0	(283)	-12.6%	-1.1%	0.0%	-0.2%	0.0%	0.0%	-13.9%
	0.00	2018	2,127	1,846	2,101	2,128	2,109	2,127	2,127	1,802	(281)	281	(26)	0.7	(17.6)	(0.0)	0.0	(325)	-13.2%	-1.2%	0.0%	-0.8%	0.0%	0.0%	-15.3%
99.85%	0.00	2019	2,124	1,817	2,104	2,125	2,097	2,124	2,124	1,771	(307)	307	(20)	1.3	(27.2)	(0.1)	(0.3)	(353)	-14.5%	-0.9%	0.1%	-1.3%	0.0%	0.0%	-16.6%
106.48%	0.00	2020	2,261	1,931	2,106	2,263	2,242	2,261	2,261	1,757	(330)	330	(155)	1.1	(19.2)	(0.5)	(0.8)	(505)	-14.6%	-6.9%	0.1%	-0.8%	0.0%	0.0%	-22.3%
99.95%	0.00	2021	2,260	1,911	2,109	2,262	2,231	2,259	2,259	1,729	(350)	350	(152)	1.6	(29.1)	(0.9)	(1.4)	(531)	-15.5%	-6.7%	0.1%	-1.3%	0.0%	-0.1%	-23.5%
96.97%	0.00	2022	2,192	1,822	2,142	2,196	2,158	2,191	2,189	1,738	(370)	370	(50)	3.9	(33.4)	(1.3)	(2.5)	(453)	-16.9%	-2.3%	0.2%	-1.5%	-0.1%	-0.1%	-20.7%
101.80%	0.00	2023	2,231	1,845	2,170	2,237	2,193	2,229	2,227	1,745	(387)	387	(62)	6.1	(38.4)	(1.7)	(3.8)	(486)	-17.3%	-2.8%	0.3%	-1.7%	-0.1%	-0.2%	-21.8%
101.49%	0.00	2024	2,264	1,860	2,191	2,274	2,222	2,262	2,259	1,746	(404)	404	(73)	9.2	(42.4)	(2.1)	(5.3)	(518)	-17.9%	-3.2%	0.4%	-1.9%	-0.1%	-0.2%	-22.9%
101.52%	0.00	2025	2,299	1,877	2,214	2,312	2,255	2,296	2,292	1,751	(422)	422	(84)	13.3	(44.3)	(2.6)	(7.2)	(547)	-18.4%	-3.7%	0.6%	-1.9%	-0.1%	-0.3%	-23.8%
100.87%	0.00	2026	2,319	1,879	2,224	2,338	2,274	2,316	2,309	1,746	(440)	440	(95)	18.8	(44.3)	(3.0)	(9.3)	(573)	-19.0%	-4.1%	0.8%	-1.9%	-0.2%	-0.4%	-24.7%
97.48%	0.00	2027	2,260	1,802	2,247	2,290	2,216	2,257	2,249	1,761	(458)	458	(13)	30.2	(44.3)	(3.4)	(10.8)	(499)	-20.3%	-0.6%	1.3%	-2.0%	-0.2%	-0.5%	-22.1%
101.18%	0.00	2028	2,287	1,812	2,273	2,328	2,243	2,283	2,273	1,777	(475)	475	(14)	40.7	(44.3)	(3.8)	(13.6)	(510)	-20.8%	-0.6%	1.8%	-1.9%	-0.2%	-0.6%	-22.3%
101.08%	0.00	2029	2,312	1,820	2,297	2,365	2,267	2,307	2,294	1,793	(491)	491	(15)	53.8	(44.3)	(4.2)	(17.1)	(518)	-21.3%	-0.6%	2.3%	-1.9%	-0.2%	-0.7%	-22.4%
101.04%	0.00	2030	2,335	1,828	2,320	2,405	2,291	2,331	2,314	1,812	(507)	507	(16)	69.6	(44.3)	(4.7)	(21.2)	(523)	-21.7%	-0.7%	3.0%	-1.9%	-0.3%	-0.9%	-22.4%
100.85%	0.00	2031	2,355	1,834	2,339	2,444	2,311	2,350	2,330	1,830	(522)	522	(16)	88.2	(44.3)	(5.1)	(25.5)	(525)	-22.2%	-0.7%	3.7%	-1.9%	-0.3%	-1.1%	-22.3%
100.77%	0.00	2032	2,373	1,837	2,356	2,483	2,329	2,368	2,344	1,851	(536)	536	(17)	109.6	(44.3)	(5.5)	(29.5)	(523)	-22.6%	-0.7%	4.6%	-1.9%	-0.3%	-1.2%	-22.0%
100.66%	0.00	2033	2,389	1,840	2,371	2,523	2,345	2,383	2,356	1,872	(549)	549	(18)	133.5	(44.3)	(5.9)	(33.4)	(517)	-23.0%	-0.7%	5.6%	-1.9%	-0.3%	-1.4%	-21.7%
100.45%	0.00	2034	2,400	1,838	2,381	2,559	2,355	2,393	2,363	1,891	(562)	562	(18)	159.5	(44.3)	(6.3)	(37.1)	(509)	-23.4%	-0.8%	6.6%	-1.8%	-0.3%	-1.5%	-21.2%
99.95%	0.00	2035	2,399	1,824	2,380	2,586	2,354	2,392	2,358	1,902	(574)	574	(19)	187.6	(44.3)	(6.7)	(40.6)	(497)	-23.9%	-0.8%	7.8%	-1.8%	-0.4%	-1.7%	-20.7%
100.52%	0.00	2036	2,411	1,825	2,392	2,628	2,367	2,404	2,367	1,928	(586)	586	(19)	217.4	(44.3)	(7.1)	(43.9)	(483)	-24.3%	-0.8%	9.0%	-1.8%	-0.4%	-1.8%	-20.0%
100.52%		2037	2,424								(597)	597													
100.52%		2038	2,436								(609)	609													
100.52%		2039	2,449								(621)	621													
100.52%		2040	2,461								(634)	634													
100.52%		2041	2,474								(646)	646													
100.52%		2042	2,487								(659)	659													
100.52%		2043	2,500								(672)	672													
100.52%		2044	2,513								(686)	686													
100.52%		2045	2,526								(700)	700													
100.52%		2046	2,539								(714)	714													
100.52%		2047	2,552								(728)	728													
100.52%		2048	2,565								(742)	742													
100.52%		2049	2,579								(757)	757													
100.52%		2050	2,592								(772)	772													

470168

	Nameplate PV							Number of Cars			Number of EHPs			Load		EE
									840700			404344				
Year	PV Base	PV MW GMP	PV Peak Hr Factor	PV Peak HR	Wind OnShore MW	Wind OffShore MW	Total Wind	EV Base	% Light Duty Cars	Peak kW/car	EHP Base	% Homes	Peak kW/EHP	Load % Before DER	Load % After DER	EE%
2005																
2006																
2007																
2008																
2009																
2010																
2011																
2012																
2013																
2014																
2015																
2016																
2017																
2018																
2019																
2020	291	291	-0.53	HE16	25	30	55	2946	0.35%	0.387	1848	0.46%	-0.414			
2021	394	394	-0.39	HE17	25	30	55	4533	0.54%	0.363	3752	0.93%	-0.373	-0.05%	-1.56%	5.88%
2022	498	498	-0.10	HE18	25	30	55	7039	0.84%	0.558	6052	1.50%	-0.421	-3.03%	0.55%	5.71%
2023	601	601	-0.10	HE18	25	30	55	10605	1.26%	0.578	8752	2.16%	-0.436	1.80%	0.38%	4.56%
2024	704	704	-0.10	HE18	35	30	65	15288	1.82%	0.602	12052	2.98%	-0.443	1.49%	0.07%	4.60%
2025	808	808	-0.10	HE18	45	400	445	21305	2.53%	0.624	15952	3.95%	-0.449	1.52%	0.30%	4.40%
2026	901	901	-0.11	HE18	55	400	455	29494	3.51%	0.638	20652	5.11%	-0.453	0.87%	-0.33%	4.22%
2027	984	984	-0.01	HE19	65	400	465	39962	4.75%	0.755	26352	6.52%	-0.409	-2.52%	0.89%	4.05%
2028	1060	1060	-0.01	HE19	75	400	475	52855	6.29%	0.770	33152	8.20%	-0.412	1.18%	0.88%	3.77%
2029	1128	1128	-0.01	HE19	85	400	485	68623	8.16%	0.784	41352	10.23%	-0.413	1.08%	0.93%	3.46%
2030	1189	1791	-0.01	HE19	125	930	1055	87321	10.39%	0.797	51152	12.65%	-0.414	1.04%	1.05%	3.17%
2031	1244	1951	-0.01	HE19	125	930	1055	109241	12.99%	0.808	60462	14.95%	-0.421	0.85%	1.01%	2.92%
2032	1293	2111	-0.01	HE19	125	930	1055	133813	15.92%	0.819	69307	17.14%	-0.426	0.77%	1.10%	2.70%
2033	1337	2271	-0.01	HE19	125	930	1055	161266	19.18%	0.828	77709	19.22%	-0.430	0.66%	1.15%	2.49%
2034	1377	2431	-0.01	HE19	125	930	1055	190458	22.65%	0.838	85691	21.19%	-0.433	0.45%	1.04%	2.31%
2035	1414	2591	-0.01	HE19	125	930	1055	222046	26.41%	0.845	93274	23.07%	-0.435	-0.05%	0.55%	2.15%
2036	1446	2751	-0.01	HE19	125	930	1055	254981	30.33%	0.853	100478	24.85%	-0.437	0.52%	1.40%	2.00%
2037		2911			125	930	1055	360068.5	42.83%		153043	37.85%				
2038		3071			125	930	1055	465156	55.33%		209651	51.85%				
2039		3231			125	930	1055	570243.5	67.83%		266259	65.85%				
2040		3691			140	1065	1205	675331	80.33%		322867	79.85%				
2041		3851			140	1065	1205	692145	82.33%		330954	81.85%				
2042		4011			140	1065	1205	708959	84.33%		339041	83.85%				
2043		4171			140	1065	1205	725773	86.33%		347128	85.85%				
2044		4331			140	1065	1205	742587	88.33%		355215	87.85%				
2045		4491			170	1335	1505	759401	90.33%		363302	89.85%				
2046		4651			170	1335	1505	776215	92.33%		371388	91.85%				
2047		4811			170	1335	1505	793029	94.33%		379475	93.85%				
2048		4971			170	1335	1505	809843	96.33%		387562	95.85%				
2049		5131			170	1335	1505	826657	98.33%		395649	97.85%				
2050		5291			170	1335	1505	843471	100.33%		403736	99.85%				

Avg. last 15 yrs	1.3%	0.3%	0.8%	1.3%	1.2%	1.3%	1.3%	**-0.4%**
Avg. last 10 yrs	1.5%	0.3%	0.8%	1.5%	1.4%	1.5%	1.5%	**-0.7%**
Avg. last 5 yrs	2.0%	1.0%	0.7%	2.0%	1.7%	2.0%	1.9%	**-0.9%**
BASE 2021								
Avg. next 5 yrs	0.5%	-0.3%	1.1%	0.7%	0.4%	0.5%	0.4%	**0.2%**
Avg. next 10 yrs	0.4%	-0.4%	1.0%	0.8%	0.4%	0.4%	0.3%	**0.6%**
Avg. next 15 yrs	0.4%	-0.3%	0.8%	1.0%	0.4%	0.4%	0.3%	**0.7%**

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

Division 1-16

Request:

The RIE Gas Long-Range Resource and Requirements Plan for the Forecast period 2022/2023 to 2026/2027 indicates that the Company projects the residential heating market to increase through Planning Year 2027 (page 4). Concurrently, RIE discusses the impact of increasing adoption of electric heat pumps in peak electric load forecasting and relies on those projections, in part, for investments under System Capacity and Area Planning Reviews as well as the Grid Modernization Plan (pages 10-11). Explain why the electric ISR includes GMP and other investments for increased electric heating load from fuel switching customers while at the same time the Company forecasts increases in the number of gas customers and usage. Provide a detailed discussion on the relationship between the energy forecasts used in the gas and electric infrastructure plans. Describe how the Company avoids duplicating Rhode Island customer energy needs and associated capital investment.

Response:

Per page 4 of the Rhode Island Energy Gas Long-Range Resource and Requirements Plan for the Forecast period 2022/2023 to 2026/2027 ("Gas Long-Range Plan"): "…the residential heating market is projected to increase by an average of 473,000 dekatherms per year, the Residential Non-Heating market is projected to decrease by an average of 8,800 dekatherms per year."

On the same page: "the Company is projecting its Base Case design year sendout requirements to increase over the five-year forecast period by an average of 449 MDth, or approximately 1.0 percent, per year (see Section III.F.), and design day sendout to increase by an average of 4,292 Dth, or 1.1 percent, per year. This change represents an approximate increase of 1% per year." The base case and design day increases are approximately one percent per year for a five- year period. This typical one percent increase should not be used as a comparison to Rhode Island Energy's Act on Climate-related efforts in either the electric or gas business. Instead, the Company encourages a focus on Section IV.E. Rhode Island Act on Climate and Gas Decarbonization in the Gas Long-Range Plan.

Specifically: "The Company is committed to advancing Rhode Island's Act on Climate's (AOC) netzero GHG emissions future by 2050 and supports the various efforts underway to further develop the plans for the implementation of Act on Climate requirements including through the PUC initiated Docket 22-01-NG related to the future of the gas distribution business, the development of the Executive Climate Change Coordinating Council's (EC4) 2022 report and the development of RIE's AOC Report (to be released early 2023) in response to the AOC requirements associated with the recent sale transaction."

Prepared by or under the supervision of: Ryan Constable

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And: "The Company will utilize the outcomes from Docket 22-01-NG, EC4 work, as well as additional RIE analysis associated with its AOC Report to inform future LRP reports." The AOC Report is expected to create a number of scenarios and so no specific scenario will be immediately incorporated into the LRP.

The Company began communications regarding the gas and electric forecasts related to the Act on Climate in August 2022 after a consultant was selected to perform the AOC Report. As described in the Gas Long Range Plan, the AOC Report is expected to be completed in early 2023. A detailed comparison cannot be provided until the report is complete; however, the Company remains committed to avoiding duplication of customer energy needs and associated capital investment. Based on current forecasts impacting the Fiscal Year 2024 Gas and Electric ISR Plans, there is no current duplication. The Company will continue communications between the gas and electric businesses for future forecasts and future ISR Plans.

Further, the Company has explained in various meetings that the electric forecast used within the upcoming GMP is used to test the electric system sufficiently to determine if foundational grid modernization investments are cost effective. The Company has explained that the feeder and wire investments would be recommended following actual customer adoption of the heating and transportation adoption. This again reinforces the Company's commitment to avoid duplication.

Prepared by or under the supervision of: Ryan Constable

Division 1-17

Request:

Regarding Company response to Docket 5209, FY 2023 ISR Plan, DIV 1-4 (in part)

Q: Describe potential system impacts expected with increased EV charging and the steps the Company is taking to monitor and manage those impacts.

Response: The potential system impacts with increased EV charging are similar to any increasing load impacts. These impacts are largely related to capacity and voltage constraints. However, certain EV charging segments are conducive to intelligent management to reduce these system impacts. The Company has demonstrated how this feature of EV charging load can be leveraged in its SmartCharge Rhode Island program. In that program Customers are financially incentivized to charge their EVs during off-peak periods, there-by increasing utilization of existing assets and minimizing system impacts.

In the FY 2024 proposed plan, the Company discusses adding EV load impacts to peak forecasts (page 10). Further, the Company states that "(a)dditional factors adding complexity to the operation of the distribution system are EV charging, electric heat pump conversions, needed reliability improvements, robust VVO/CVR systems and established time varying rates for consumers" (page 21) as rationale for GMP.

a. How is the Company accounting for its current capability to manage EV charging in developing its 15-year load forecast (Chart 3, page 10)?
b. How is the Company leveraging its current managed charging capabilities in determining GMP investment needs?

Response:

a. The SmartCharge Rhode Island program is being evaluated on a small percentage of electric vehicle ("EV") owners. The Company would not apply a program with a small population of vehicles to a state-wide forecast until that program has a much higher participation percentage. The SmartCharge RI program does provide promise; however, even if the program shows consistent and reliable summer evening peak reduction, the forecast must still evaluate EV base load without program reductions. Forecasts are also moving toward evaluation of a number of multiple periods within a year versus the traditional summer and winter peaks, which will require the program to further adapt to the emerging critical periods.

Prepared by or under the supervision of: Ryan Constable

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b. Similar to other current programs, the management of variable distributed energy resources is tied to fixed definitions of on-peak and off-peak periods, critical peak prices, and other non-real time, non-localized distribution system indicators. None of the existing management systems is tied to real time localized distribution system issues as would be required in the future. Therefore, those current programs are not accounted for in determining the investment needs that fall under the grid modernization framework. There is some potential to adapt and leverage the SmartCharge RI program after grid modernization investments are in place. The grid modernization investments will be those investments that determine the real-time localized needs that would become inputs to programs such as these. With a Distributed Energy Resource Management System ("DERMS") leveraging the SmartCharge RI program participant database and with new communication methods, the SmartCharge RI program can be adapted to continue to provide EV management benefits.

Prepared by or under the supervision of: Ryan Constable

Division 1-18

Request:

What are the Company's current demand response (DR) programs and the types of loads that are managed? Provide the major underlying components necessary to implement the programs (Company infrastructure, systems, software, and/or customer devices, etc.). Discuss functionality including whether the Company relies on passive load management (time-varying rates, communication to customers, incentive programs, etc.), or active load management (direct load control via customer or Company owned devices). Can the Company integrate larger numbers and types of Customer loads, such as EVs and heat pumps, with existing systems? Explain in detail.

Response:

The Company offers its ConnectedSolutions demand response ("DR") programs for both residential and business customers. For residential, managed loads include thermostats, energy storage systems, and solar inverters. Incentive levels and event parameters vary depending on the load type. For businesses, the program is load-agnostic, but common loads include HVAC, lighting, and energy storage. There are two participation options: Targeted Dispatch, primarily for load reductions, and Daily Dispatch, primarily for energy storage. Additional information can be found at https://www.rienergy.com/RI-Home/ConnectedSolutions/ and https://www.rienergy.com/RI-Business/Energy-Saving-Programs/ConnectedSolutions.

Regarding the major underlying components necessary to implement the programs:

- Company Infrastructure - none
- Systems/Software – Demand Response Management System ("DRMS") (outsourced)
- Customer Devices – thermostats, energy storage, solar inverters, control boxes for business customers

Regarding passive load management:

- The Company does not offer Time-Varying Rates
- Communication to Customers – this is not a normal part of the DR program, but the Company has used it in emergency situations to request customers to curtail load to prevent larger outages

Prepared by or under the supervision of: Brett Feldman

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- Incentive Programs - ConnectedSolutions is an incentive program for businesses that want to control their own loads

Regarding functionality, ConnectedSolutions is active load management of customer-owned thermostats, energy storage, and solar inverters.

The Company can integrate larger numbers of residential and non-residential customers and types of customer loads with existing systems. Heat pumps are currently included in the program, and with the Company's existing software/systems, it is possible to expand ConnectedSolutions to include DR from EVs.

Prepared by or under the supervision of: Brett Feldman

Division 1-19

Request:

The Company states that it anticipates completion of 100% of the annual capacity reviews in February 2023. What is the budgeted amount for this potential work in the proposed ISR Plan? Provide the results of the capacity reviews for the past three years, including a description of the planning criteria violation, proposed solution, actual project implemented, timeframe, and cost.

Response:

There is no budgeted amount for the annual capacity reviews included in the ISR plan for FY 2024.

For ISR FY 2021, please see Attachments 9A - Feeder Load Projections and 9B - Transformer Load Projections of the pre filing documents for the results of that year's capacity reviews.

For ISR FY 2022, please see Attachment 10-1 Load Projections of the pre filing documents for the results of that year's capacity reviews.

For ISR FY 2023, please see Attachment 10-1 of the pre filing documents for the results of that year's capacity reviews.

Please see the Attachment DIV 1-19, which includes more detailed information for each particular feeder/transformer overload concern, and what actions were taken if any.

Planning Area	Substation	Feeder	FY ISR	2019 % Rating	2020 % Rating	2021 % Rating	2022 % Rating	2023 % Rating	Solution	Cost
BSVN	Nasonville	127W43	FY 21	101%	103%	103%	N/A	N/A	Transferred load to the 127W41.	$0
BSVS	Pawtucket #1	107W50	FY 21	117%	0	0	N/A	N/A	Transferred load to the 102W42. Transferred all load to new Dunnell Park Substation in 2021.	$0
BSVS	Valley	102W51	FY 21	105%	90%	90%	N/A	N/A	Transferred load to the 102W52.	$0
NEWPORT	Kingston	131J12	FY 21	100%	99%	99%	N/A	N/A	No action taken. Negative load growth.	
PROVIDENCE	Knightsville	66J1	FY 21	106%	105%	105%	N/A	N/A	No action taken, Control Center monitored during summer months. Feeder to be retired and converted to 15kV per Providence Study.	
PROVIDENCE	Knightsville	66J2	FY 21	104%	103%	103%	N/A	N/A	No action taken, Control Center monitored during summer months. Feeder to be retired and converted to 15kV per Providence Study.	
BSVN	Nasonville	127W43	FY 22	N/A	118%	116%	116%	N/A	Transferred load to the 127W41.	$0
BSVN	Staples	112W44	FY 22	N/A	103%	102%	101%	N/A	No action taken, Control Center monitored during summer months.	
BSVS	Pawtucket #1	107W60	FY 22	N/A	105%	15%	15%	N/A	Transferred load to the 107W66. Transferred all load to new Dunnell Park Substation in 2021.	$0
BSVS	Valley	102W51	FY 22	N/A	102%	86%	86%	N/A	Transferred load to the 102W52.	$0
CRIW	Hopkins Hill	63F6	FY 22	N/A	102%	102%	103%	N/A	New switch added. Transferred load to 155F8. CRIW Area Study will eventually offload with Weaver Hill recommendation.	$18K
EB	Barrington	4F2	FY 22	N/A	102%	101%	0%	N/A	No action taken, Control Center monitored during summer months. Per East Bay Study all load will be transferred to new East Providence Substation.	$0
NEWPORT	Jepson	37W42	FY 22	N/A	101%	101%	101%	N/A	No action taken, Control Center monitored during summer months.	
NEWPORT	Eldred	45J3	FY 22	N/A	107%	106%	106%	N/A	No action taken, Control Center monitored during summer months.	
NCRI	Manton	69F3	FY 22	N/A	100%	100%	101%	N/A	No action taken, Control Center monitored during summer months.	
NCRI	Putnam Pike	38F1	FY 22	N/A	101%	101%	101%	N/A	No action taken, Control Center monitored during summer months.	
PROVIDENCE	South St	1101	FY 22	N/A	106%	104%	104%	N/A	Transferred load to the 1149.	$0
PROVIDENCE	East George	77J2	FY 22	N/A	108%	107%	106%	N/A	Transferred load to the 37J2 and performed feeder balancing.	$0
SCE	Bonnet	42F1	FY 22	N/A	102%	102%	103%	N/A	No action taken, Control Center monitored during summer months. Non-wires alternative attempted. SCE Area Study to eventually offload with project.	
SCE	Peacedale	59F3	FY 22	N/A	104%	103%	104%	N/A	No action taken, Control Center monitored during summer months. Non-wires alternative attempted. SCE Area Study to eventually offload with project.	
SCE	Wakefield	17F2	FY 22	N/A	106%	106%	107%	N/A	No action taken, Control Center monitored during summer months. Non-wires alternative attempted. SCE Area Study to eventually offload with project.	
SCE	Kenyon	68F2	FY 22	N/A	105%	105%	105%	N/A	No action taken, Control Center monitored during summer months. Non-wires alternative attempted. SCE Area Study to eventually offload with project.	
SCE	Tiverton	33F2	FY 22	N/A	102%	101%	100%	N/A	No action taken, Control Center monitored during summer months.	
SCE	Tiverton	33F4	FY 22	N/A	120%	119%	119%	N/A	Transferred load to the 33F3.	$0
BSVN	Nasonville	127W43	FY 23	N/A	N/A	104%	102%	102%	Transferred load to the 127W41.	$0
BSVS	Valley	102W51	FY 23	N/A	N/A	100%	99%	98%	Transferred load to the 102W52.	$0
CRIE	Lincoln Ave	72F6	FY 23	N/A	N/A	103%	102%	102%	Balanced feeder. CRIE area study will eventually offload with Auburn project	$0
EB	Bristol	51F2	FY 23	N/A	N/A	100%	99%	99%	No action taken. Negative load growth.	
EB	Wampanoag	48F1	FY 23	N/A	N/A	112%	111%	111%	No action taken, Control Center monitored during summer months. Feeder to be offloaded by East Providence substation.	
NEWPORT	Eldred	45J3	FY 23	N/A	N/A	101%	100%	100%	No action taken, Control Center monitored during summer months.	
PROVIDENCE	East George	77J2	FY 23	N/A	N/A	106%	105%	105%	No action taken, Control Center monitored during summer months. Feeder to be retired and converted to 15kV per Providence Study.	
SCE	Tiverton	33F3	FY 23	N/A	N/A	100%	99%	99%	No action taken. Negative load growth.	

Division 1-20

Request:

The Company discusses completion of 10 Area Studies by December 2021 and provides a link to the Rhode Island System Data Portal to access the reports (page 16). The Portal hosts four reports. Please indicate how the remaining six reports can be accessed.

Response:

The six area study reports are included as follows:

Attachment DIV 1-20-1 – Blackstone Valley South Area Study
Attachment DIV 1-20-2 – Central RI West Area Study
Attachment DIV 1-20-3 – Newport Area Study
Attachment DIV 1-20-4 – Northwest RI Area Study
Attachment DIV 1-20-5 – South County West Area Study
Attachment DIV 1-20-6 – Tiverton Area Study

These studies will not be posted to the Rhode Island System Data Portal until they are reviewed for Critical Energy Infrastructure Information or other confidential information. The Company will complete this review as soon as possible.

Prepared by or under the supervision of: Ryan Constable

Attachments DIV 1-20-1 through DIV 1-20-6

REDACTED

Division 1-21

Request:

Regarding the Planning Study Processes (Chart 5, page 17): Is RIE planning changes to this process under PPL ownership? Discuss in detail. What department will perform the studies in the future? What is the proposed schedule for refresh of each Area Study? How will GMP load forecast assumptions be incorporated in Area Studies?

Response:

Rhode Island Energy has no plans to change the study process as a result of PPL ownership. The study process will continue to be used to develop comprehensive area plans in parallel with existing and emerging program work and other discretionary work the Company considers necessary. Distribution Planning and Asset Management will continue to conduct the studies and the proposed refresh remains at generally 5 years, subject to various practical details. For example, the previous Providence Area Study recommended a very complex multi-year solution. It is impractical to restudy the area with major construction and major system reconfiguration in progress.

The Company does recognize that there will be fundamental changes to the planning process because of decarbonization efforts. This will drive new forecasting needs and new analysis techniques, with such new methods currently being explored to prepare the Grid Modernization Plan ("GMP"). As described in the Company's responses to DIV 1-4 and DIV 1-15, the GMP starts with the same 15-year forecast as traditional studies, but then projects the forecast to 2050. First, the traditional load forecast is incorporated into the GMP. Next when the GMP is complete, the extended forecast will be used to inform future load forecast reports along with new and existing programs and actual customer Distributed Energy Resource adoption trends.

Prepared by or under the supervision of: Ryan Constable

Division 1-22

Request:

The Company during the November 1, 2022 conference call stated that it had experienced 112 breaker operations. Over what period of time did these operations take place? How many of these operations were momentary? How many of these operations were the relay fast curve in a fuse save scheme before the fuse cleared the faulted section or the fault was purely momentary? How many of these operations would have occurred even if there was a down line circuit recloser? How many of the operations were multiple operations as a result of a main line fault not cleared by a tap fuse? How many of the operations resulted in a sustained fault which locked open the breaker? Did the Company download the event recorder information for each event and if yes provide a copy?

Response:

From October 30, 2021 through October 30, 2022 Rhode Island Energy ("RIE" or the "Company") experienced 112 sustained circuit breaker interruptions. During fair weather days[1] the system averaged one circuit breaker outage approximately every 3 days.

None of the operations was a momentary interruption or part of a fast trip fuse saving scheme. The Company currently employs a fuse blowing philosophy. That is, each protective device is set to fully coordinate with other devices. The Company moved away from fuse saving to reduce momentary interruptions to customers and to better manage non reclose assurance requests from line workers. The Company is currently reviewing the differences between fuse saving and fuse blowing protection philosophies. PPL's Pennsylvania distribution system employs fuse saving, but because of the difference in circuit topology between the Rhode Island and Pennsylvania systems, a fuse save strategy is unlikely to be adopted.

Had downstream sectionalizing reclosers been in place, 31 circuit breaker interruptions would have been avoided. Had self-healing recloser schemes (aka, FLISR - Fault Location, Isolation and Service Restoration) been in place, 83 of the 112 events would have substantially reduced customer interruptions ("CI") and customer interruption minutes ("CMI").

Three of the 112 interruptions also had downstream devices operate along with the circuit breakers. Two occurred during storms when multiple events occurred on the system (02/18/2022 – 175 events and 07/02/2022 lightning storm – 29 events). The last event occurred on 09 /11/2022 and was perceived to be a mis-operation on a Rhode Island / Massachusetts feeder between the station breaker and the line recloser. However, the fault records retrieved from the

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[1] When the daily SAIDI was less that half the TMED exclusion threshold of 6.88 minutes.

circuit breaker relay suggest galloping conductors caused a second fault. None of these three events was counted among the 31 that would have been improved by the placement of a sectionalizing recloser.

Fault information from distribution circuit breaker relays is retrieved on an ad hoc basis when the relay has event capturing capability and a protection scheme mis-operation is suspected. Rhode Island Energy is currently developing a database application to formally store fault records retrieved for coordination reviews. Records for 3 of the 112 events are attached in SEL AcSELerator format as Attachment DIV 1-22-1, Attachment DIV 1-22-2, and Attachment DIV 1-22-3.

Division 1-23

Request:

Explain in detail the various proposed recloser programs being implemented under both the discretionary and non-discretionary spending categories. Include proposed budgets for the term of the programs. Provide all documentation to justify the need, level of investment, and location of recloser additions.

Response:

There are two recloser programs being implemented under both the discretionary and non-discretionary spending categories. The two programs are the 'Mainline Recloser Enhancements' in the discretionary spending category and 'Grid Modernization Plan – Advanced Reclosers' in the non-discretionary spending category.

Mainline Recloser Enhancements

Proposed Budget (in 000s)

CY 2023 (9 months)	**CY 2024**	**CY 2025**	**CY 2026**	**CY 2027**
9,504	-	-	-	-

Summary of Issues: There are approximately 100 4kV and 15 kV circuits that have zero reclosers serving greater than one mile of overhead line exposure and more than 100 customers. In addition, there are approximately 70 15kV circuits that have only one recloser serving greater than five miles of overhead line exposure and more than 1,000 customers. The absence of reclosers on these circuits increases the amount of customer outages due to the lack of sectionalization and reduces the ability to remotely transfer load during an outage. The Company has determined that the lack of reclosers is a contributing factor to the rising System Average Interruption Frequency Index ("SAIFI") values.

Recommended Plan: Install reclosers prioritized based on feeder length, number of customers, type of customers, and feeder reliability values to reduce mainline fault impacts. This effort will consider future feeder rearrangements proposed by area study recommendations to ensure recloser reliability value. All reclosers will use the latest control technology aligned with the pending Grid Modernization Plan ("GMP") and location selection will be aligned with ultimate GMP implementation.

Justification: This recloser program is intended to create near term SAIFI benefits to reverse the Company's current upward trend in this metric. The program is aligned with grid modernization

Division 1-23, page 2

and represents an accelerated portion of the ultimate GMP framework regarding reclosers. Benefits are calculated in a similar manner between this program and the GMP using the USDOE ICE Calculator. The Mainline Recloser Enhancement Program will provide an approximate customer benefit of approximately $3M per year. The 20-year net present value benefit is approximately $40M.

Locations: Locations were determined and prioritized by gathering mainline outage events on circuits with less than 2 mainline reclosers, more than 500 customers, and more than 3 miles of overhead conductor. The event data was used to develop circuit interruption frequency, and location priority was ranked by those values. Attachment DIV 1-23 shows the location priority list.

Grid Modernization Plan – Advanced Reclosers

Proposed Budget (in 000s)

CY 2023 (9 Months)	CY 2024	CY 2025	CY 2026	CY 2027
17,405	25,190	25,693	26,207	26,732

Summary of Issues: The distribution system has traditionally been built to ensure adequate available capacity at all times by building the necessary distribution system capacity to accommodate forecasted peak loading on extreme weather days in accordance with the Company's planning criteria. Designing the system to meet these worst-case scenarios assuming one-way power flow eliminated or lessened the need for day-to-day load management for distribution grid management. In addition, when a fault does occur on the system, restoration has been made possible by manually switching to isolate the fault and serving with power from alternative sources where possible. As distributed energy resource ("DER") penetration increases and is located anywhere on the distribution system, it will result in possible two-way power flow, overloads in the reverse direction under light load conditions, and desensitization of protection systems during fault conditions. Similar to voltage management, the increasing complexity of the grid will require a transition away from simple autonomous controls to control schemes that are integrated across an entire feeder. The load control and near real-time power measurements provided by Advanced Reclosers, when used in combination with ADMS, enable engineering and operations personnel to automatically isolate faults and restore service ("FLISR") and better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all Rhode Island Energy customers through optimization. An accelerated deployment of Advanced Reclosers is being proposed to ensure distribution equipment is operated within its rated capacity and that faults on the system are cleared efficiently. Those areas and feeders with existing DER penetration and the greatest overload and/or protection

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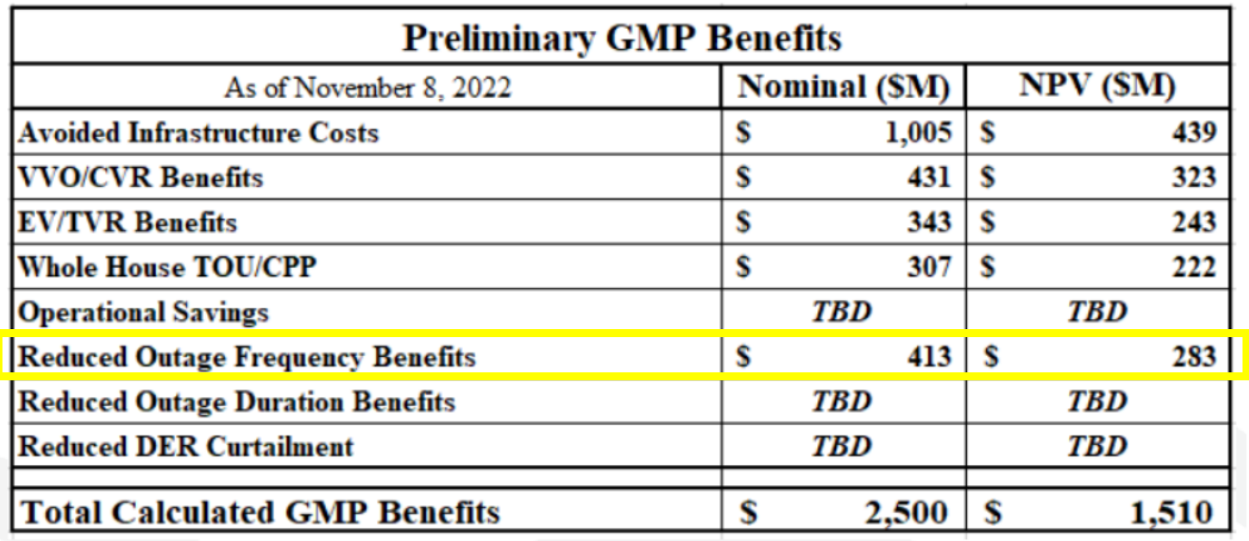
coordination risk will be prioritized. The targeted deployment of Advanced Reclosers, which is part of the Company's GMP, is forecasted to reduce both the duration and frequency of outages.

Recommended Plan: The GMP proposes investment in Advanced Reclosers on the Distribution class systems, taking into consideration Area Study solutions which may call for the reconfiguration and or conversion of certain circuits. The proposal calls for the installation of both main line and tie point reclosers.

Justification: The GMP reclosers provide a number of benefits including system visibility and sensing and operational efficiencies, but their primary benefit is improving system reliability. Preliminary results of the reliability benefits were developed using the USDOE ICE calculator and these benefits were presented in a November 2022 Power Sector Transformation Advisory Group meeting. The presentation is included in the response to DIV 1-36.

The preliminary benefits table is shown below in Table 1 with the recloser benefits highlighted.

Table 1 – Preliminary GMP Benefits



Preliminary GMP Benefits

As of November 8, 2022	Nominal ($M)	NPV ($M)
Avoided Infrastructure Costs	**$ 1,005**	**$ 439**
VVO/CVR Benefits	**$ 431**	**$ 323**
EV/TVR Benefits	**$ 343**	**$ 243**
Whole House TOU/CPP	**$ 307**	**$ 222**
Operational Savings	***TBD***	***TBD***
Reduced Outage Frequency Benefits	**$ 413**	**$ 283**
Reduced Outage Duration Benefits	***TBD***	***TBD***
Reduced DER Curtailment	***TBD***	***TBD***
Total Calculated GMP Benefits	**$ 2,500**	**$ 1,510**

Locations: Locations have not been determined for the GMP reclosers as of this time. They will be determined during the first quarter of calendar year 2023 in a similar manner to the prioritization of the Mainline Recloser Enhancement Project.

The Narragansett Electric Company
d/b/a Rhode Island Energy
In Re: Proposed FY 2024 Electric Infrastructure, Safety and Reliability Plan
Attachment DIV 1-23
Page 1 of 4

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

Circuits	Mainline Recloser Count	Average Customers Served	Tot 5yr Events	Tot 5yr CI	Tot 5yr CMI	Avg Events	Avg CI	Avg CMI	Avg Yr CKAIFI	Avg Yr CKAIDI
53-126W41	1	2346	14	28,100	1,136,588	2.8	5,620	227,318	2.40	96.90
56-155F4	1	1793	15	16,656	746,579	3.0	3,331	149,316	1.86	83.28
56-85T1	0	2760	12	20,179	1,514,028	2.4	4,036	302,806	1.46	109.71
53-112W41	1	1899	9	13,855	463,521	1.8	2,771	92,704	1.46	48.82
53-111J3	0	1087	8	7,154	497,546	1.6	1,431	99,509	1.32	91.54
53-107W61	1	2458	13	14,589	686,026	2.6	2,918	137,205	1.19	55.82
53-1201W4	0	915	5	5,417	353,882	1.0	1,083	70,776	1.18	77.35
56-16F2	1	1828	9	10,084	239,540	1.8	2,017	47,908	1.10	26.21
56-155F2	1	2009	8	10,968	804,313	1.6	2,194	160,863	1.09	80.07
53-26W3	1	2341	8	11,776	393,313	1.6	2,355	78,663	1.01	33.60
53-1201W7	0	806	7	4,020	262,620	1.4	804	52,524	1.00	65.17
53-102W44	1	2565	10	12,200	551,940	2.0	2,440	110,388	0.95	43.04
53-15F1	0	1185	5	5,434	338,072	1.0	1,087	67,614	0.92	57.06
53-107W80	1	2012	5	8,746	411,163	1.0	1,749	82,233	0.87	40.87
53-48F3	1	3079	5	13,305	1,043,379	1.0	2,661	208,676	0.86	67.77
53-18F13	1	2207	7	9,489	256,906	1.4	1,898	51,381	0.86	23.28
53-127W41	0	654	6	2,721	151,517	1.2	544	30,303	0.83	46.34
53-69F3	1	4786	7	19,363	1,143,964	1.4	3,873	228,793	0.81	47.80
53-112W43	1	986	4	3,906	239,227	0.8	781	47,845	0.79	48.52
56-63F5	1	2496	10	9,620	376,672	2.0	1,924	75,334	0.77	30.18
53-13F3	1	714	2	2,740	48,911	0.4	548	9,782	0.77	13.70
53-107W81	1	2431	13	9,233	1,138,213	2.6	1,847	227,643	0.76	93.64
56-36W42	1	1876	5	7,088	364,168	1.0	1,418	72,834	0.76	38.82
53-200W5	1	2019	5	7,611	230,135	1.0	1,522	46,027	0.75	22.80
56-87F3	1	1276	5	4,465	222,685	1.0	893	44,537	0.70	34.90
53-23F3	0	1500	5	4,833	319,537	1.0	967	63,907	0.64	42.60
56-63F3	1	2003	5	6,057	547,792	1.0	1,211	109,558	0.60	54.70

53-5F2	1	2555	7	7,515	1,034,181	1.4	1,503	206,836	0.59	80.95
53-38F5	0	1710	4	4,927	171,990	0.8	985	34,398	0.58	20.12
56-3F1	0	1899	3	5,397	442,797	0.6	1,079	88,559	0.57	46.63
53-21F4	1	2054	5	5,665	423,820	1.0	1,133	84,764	0.55	41.27
53-38F3	1	1355	4	3,724	172,393	0.8	745	34,479	0.55	25.45
53-48F6	1	1996	5	5,422	245,562	1.0	1,084	49,112	0.54	24.61
53-78F4	0	819	3	2,183	262,691	0.6	437	52,538	0.53	64.15
53-27F5	1	3070	4	7,840	480,951	0.8	1,568	96,190	0.51	31.33
53-76F7	1	2657	5	6,749	346,631	1.0	1,350	69,326	0.51	26.09
56-203W3	1	1438	6	3,613	137,107	1.2	723	27,421	0.50	19.07
53-112W42	1	2900	4	7,210	213,771	0.8	1,442	42,754	0.50	14.74
53-127W42	0	1038	3	2,533	175,564	0.6	507	35,113	0.49	33.83
56-42F1	1	2894	7	7,040	370,245	1.4	1,408	74,049	0.49	25.59
56-155F6	1	1727	6	4,132	240,392	1.2	826	48,078	0.48	27.84
53-102W52	0	1428	6	3,292	104,224	1.2	658	20,845	0.46	14.60
56-52F1	1	1642	4	3,754	153,814	0.8	751	30,763	0.46	18.73
53-102W42	1	3144	7	7,182	152,283	1.4	1,436	30,457	0.46	9.69
53-7F2	1	2046	7	4,660	123,923	1.4	932	24,785	0.46	12.11
53-48F5	1	3061	5	6,866	248,663	1.0	1,373	49,733	0.45	16.25
53-13F9	1	3090	8	6,886	870,929	1.6	1,377	174,186	0.45	56.37
53-18F10	1	2497	3	5,549	117,322	0.6	1,110	23,464	0.44	9.40
53-18F8	0	1762	3	3,899	169,715	0.6	780	33,943	0.44	19.26
53-20F1	0	761	3	1,651	49,886	0.6	330	9,977	0.43	13.11
53-50F2	0	2130	3	4,511	272,864	0.6	902	54,573	0.42	25.62
53-107W83	0	1418	3	2,993	132,534	0.6	599	26,507	0.42	18.69
53-5F3	1	2493	3	5,096	271,489	0.6	1,019	54,298	0.41	21.78
56-61F2	0	1452	2	2,918	142,744	0.4	584	28,549	0.40	19.66
56-14F2	1	1609	2	3,224	54,640	0.4	645	10,928	0.40	6.79
53-20F2	1	2095	3	4,120	183,344	0.6	824	36,669	0.39	17.50
56-64F1	0	1342	3	2,601	263,557	0.6	520	52,711	0.39	39.28
53-13F5	0	3919	2	7,428	36,627	0.4	1,486	7,325	0.38	1.87
56-203W5	1	2343	3	4,372	46,549	0.6	874	9,310	0.37	3.97
56-36W41	1	2088	2	3,886	310,346	0.4	777	62,069	0.37	29.73
56-22F6	1	1937	2	3,030	111,550	0.4	606	22,310	0.31	11.52

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56-61F3	0	987	3	1,501	74,373	0.6	300	14,875	0.30	15.07
56-63F4	1	2111	2	3,188	227,552	0.4	638	45,510	0.30	21.56
53-13F10	1	2444	3	3,677	267,180	0.6	735	53,436	0.30	21.86
53-126W54	1	738	4	1,088	20,392	0.8	218	4,078	0.29	5.53
56-72F6	0	2411	4	3,422	368,336	0.8	684	73,667	0.28	30.55
53-27F1	1	1712	3	2,375	67,438	0.6	475	13,488	0.28	7.88
53-18F7	1	3095	2	4,172	311,904	0.4	834	62,381	0.27	20.16
53-13F4	1	3837	3	5,171	519,775	0.6	1,034	103,955	0.27	27.09
56-57J2	0	624	3	829	150,392	0.6	166	30,078	0.27	48.20
56-36W43	0	1748	3	2,259	88,075	0.6	452	17,615	0.26	10.08
56-72F4	1	2636	3	3,219	102,324	0.6	644	20,465	0.24	7.76
56-22F3	0	1153	3	1,394	93,050	0.6	279	18,610	0.24	16.14
53-76F4	1	4997	2	5,950	114,175	0.4	1,190	22,835	0.24	4.57
53-76F1	1	2094	1	2,295	134,517	0.2	459	26,903	0.22	12.85
53-51F1	1	2100	2	2,196	127,527	0.4	439	25,505	0.21	12.15
56-65J12	0	740	1	746	45,350	0.2	149	9,070	0.20	12.26
53-107W66	1	3326	13	3,325	271,540	2.6	665	54,308	0.20	16.33
56-87F6	0	736	1	732	131,565	0.2	146	26,313	0.20	35.75
56-72F2	1	2646	1	2,626	175,700	0.2	525	35,140	0.20	13.28
56-32J14	0	565	1	560	9,548	0.2	112	1,910	0.20	3.38
53-23F1	1	1518	1	1,503	63,126	0.2	301	12,625	0.20	8.32
56-14F4	0	879	1	870	83,955	0.2	174	16,791	0.20	19.10
56-83F4	1	1918	2	1,864	186,034	0.4	373	37,207	0.19	19.40
53-38F4	1	2571	3	2,482	116,758	0.6	496	23,352	0.19	9.08
53-1201W3	1	1790	1	1,711	75,284	0.2	342	15,057	0.19	8.41
53-1201W6	1	3328	7	3,132	216,812	1.4	626	43,362	0.19	13.03
53-38F6	1	2809	3	2,487	230,131	0.6	497	46,026	0.18	16.39
56-150F2	0	1735	4	1,322	68,625	0.8	264	13,725	0.15	7.91
56-203W1	1	1430	5	996	114,427	1.0	199	22,885	0.14	16.00
56-37W5	0	1983	9	1,262	78,933	1.8	252	15,787	0.13	7.96
53-1201W1	1	1707	3	1,005	76,450	0.6	201	15,290	0.12	8.96
56-3F2	1	1901	2	1,085	24,862	0.4	217	4,972	0.11	2.62
56-52F3	1	2698	2	1,512	62,288	0.4	302	12,458	0.11	4.62
53-1201W5	1	2842	5	1,491	93,639	1.0	298	18,728	0.10	6.59

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56-150F8	1	2533	1	1,210	186,098	0.2	242	37,220	0.10	14.69
53-48F2	1	572	2	271	30,568	0.4	54	6,114	0.09	10.69
56-37W6	0	1628	6	755	87,920	1.2	151	17,584	0.09	10.80
53-102W54	1	2325	2	1,017	89,956	0.4	203	17,991	0.09	7.74
56-87F5	0	1436	1	616	241,793	0.2	123	48,359	0.09	33.68
56-150F6	1	3525	6	1,450	174,677	1.2	290	34,935	0.08	9.91
53-108W63	0	2829	2	1,021	16,024	0.4	204	3,205	0.07	1.13
53-1201W2	1	3145	2	747	97,110	0.4	149	19,422	0.05	6.18
56-16F4	1	1663	1	373	746	0.2	75	149	0.04	0.09
53-18F9	1	3626	1	602	9,030	0.2	120	1,806	0.03	0.50
56-87F1	1	1127	1	57	456	0.2	11	91	0.01	0.08
53-76F2	0	3984	1	89	2,889	0.2	18	578	0.00	0.15
56-150F4	1	1951	2	31	3,067	0.4	6	613	0.00	0.31
56-72F5	1	3341	1	6	780	0.2	1	156	0.00	0.05

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Division 1-24

Request:

National Grid previously performed a study that evaluated recloser replacements and the need for additional reclosers on the Rhode Island system (see National Grid Form 3A Recloser Replacement Study NE dated March 14, 2016). The projects emanating from this study are being completed under the discretionary spending category in the ISR Plan.

a. Provide a list of recloser replacements both completed and planned under this study with actual/estimated costs.

b. Are the reclosers compatible with RIE's proposed communication and control systems in the GMP? Explain.

c. Provide a detailed explanation of what portions of the 2016 recloser study completed by National Grid that RIE is retaining and what portion RIE is abandoning.

Response:

a. The Form 3A program was designed to replace near end-of-life assets. The average service life of each unit exceeded 25 years. Operational issues that initiated the program included battery charging circuit malfunctions and severe rusting of the control cabinets which led to mis-operations. New recloser placements were not part of this program. A list of Form 3A reclosers identified for replacement is shown in Attachment DIV 1-24.

b. The reclosers are compatible with Rhode Island Energy's proposed communication and control systems for the Grid Modernization Plan ("GMP") reclosers because they can be adopted into Rhode Island Energy's Outage Management System for remote control and to a Programable Logic Control for automatic switching schemes.

c. Rhode Island Energy has no plan to abandon reclosers installed as part of the Form 3A program.

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Form 3A Replacement List

Dist	Town	Feeder	Pole Location	WR	Field Complete	Estimated Cost	Actual Costs
Capital	Johnston	2211	p.0764 ROW of Manton 6 Sub	27894177	Yes	$71,600	$ 178,120
Capital	Providence	2211	p. 0808 ROW of Cowens plastics Tap	N/A	No	$71,600	TBD
Capital	Johnston	2227	p. 5 ROW of p35 W. Greenville Rd	24689446	Yes	$71,600	$ 109,388
Capital	Providence	13F3	p. 3 East Frontage Rd	23988996	Yes	$71,600	$ 80,397
Capital	Smithfield	23F6	p. 13-25 Whipple Rd	24662755	Yes	$71,600	$ 77,055
Capital	Cranston	27F2	p.193 1/2 pontiac Ave	25846596	Yes	$71,600	$ 62,099
Capital	Scituate	34F1	p.97 Chopmist Hill Rd.	22923543	Yes	$71,600	$ 70,549
Capital	Scituate	34F1	p.204-1 Danielson pike	22923589	Yes	$71,600	$ 52,011
Capital	Glocester	34F3	p.76-51 Reynolds Rd.	26018369	Yes	$71,600	$ 100,350
Capital	Smithfield	38F2	p. 48 pleasant View Ave	N/A	No	$71,600	TBD
Capital	Smithfield	38F4	p.29 Esmond St. (Device Removed)	22919861	Yes	$71,600	$ 3,328
Capital	E. Providence	48F5	p.39 S. Broadway	24962121	Yes	$71,600	$ 104,667
Capital	E. Providence	48F6	p.21 Sutton Ave	24962134	Yes	$71,600	$ 78,796
Capital	Bristol	51F2	p.32 Franklin St.	23220996	Yes	$71,600	$ 112,246
Capital	Bristol	51F3	p.2 1/2 popasquash Rd.	25888350	Yes	$71,600	$ 44,049
Capital	Barrington	53-2291	p.9097 County Rd. (Work completed outside of program)	N/A	Yes	$71,600	N/A
Capital	Barrington	5F1	p.6 New Meadow Rd.	23220931	Yes	$71,600	$ 103,085
Capital	Cranston	72F3	p. 27-50 Sockanosett Cross Rd	24532414	Yes	$71,600	$ 68,699
Capital	E. Providence	78F3	p.27 Woodward Ave	22934175	Yes	$71,600	$ 72,049
Capital	Providence	79F2	p.27 Camp St.	22934175	Yes	$71,600	$ 72,049
Capital	Providence	79F2	p.13 Doyle AVE.	22934197	Yes	$71,600	$ 71,930
Capital	Cranston	7F2	p.1 Chestnut Hill	25846399	Yes	$71,600	$ 18,295
Coastal	W. Warwick	14F3	p. 92 Providence St (Device Removed)	26686029	Yes	$71,600	$ 5,317
Coastal	Narragansett	17F2	p. 16 South pier Rd	25046367	Yes	$71,600	$ 65,842
Coastal	W. Warwick	29F1	p. 1 pontiac Ave.	N/A	No	$71,600	TBD
Coastal	Tiverton	33F2	p. 119 Main Rd.	21100070	Yes	$71,600	$ 52,934
Coastal	Tiverton	33F2	p. 114 Main Rd.	25004724	Yes	$71,600	$ 11,206
Coastal	Tiverton	33F3	p. 240 Nannaquaket Rd.	23132551	Yes	$71,600	$ 69,984
Coastal	Coventry	54F1	p.143 Harkney Hill Rd.	24162389	Yes	$71,600	$ 65,033
Coastal	South Kingston	59F3	p.60 Commodore Oliver Hazard perry Highway	26017727	Yes	$71,600	$ 63,836
Coastal	E. Greenwich	61F3	p.63-1 S. County Trail	28337391	Yes	$71,600	$ 92,863
Coastal	E. Greenwich	61F3	p.57-51 S. County Trail (Device Removed)	25812912	Yes	$71,600	$ 7,972
Coastal	W. Greenwich	63F2	p. 219 New London Turnpike	25054558	Yes	$71,600	$ 82,118
Coastal	South Kingston	68F1	p.2-50 Kingstown Road	25812911	Yes	$71,600	$ 85,175
Coastal	Charlestown	68F3	p.68 Old post Road	25476746	Yes	$71,600	$ 60,867
Coastal	South Kingston	68F5	p. 43-1 Fairgrounds Road	N/A	No	$71,600	TBD
Coastal	North Kingstown	83F2	p.5 3/4 Roger Williams Way	25437575	No	$71,600	TBD

Division 1-25

Request:

Provide a copy of the systemwide fault current study and "protective coordination study" and the standards followed for performing such a study.

Response:

Rhode Island Energy ("RIE" or the "Company") does not perform a systemwide fault current study. In lieu of a statewide study, RIE performs more resource efficient fault current analysis and protective coordination reviews for specific issues and projects. As examples, a distributed generation impact study includes complex coordination issues and certain area studies identify specific localized coordination concerns. These issues are reviewed, and recommendations are developed during those studies. Where there are no expected coordination concerns, such as with 2 to 3 reclosers in series on a circuit, coordination reviews are done during early stages of execution.

For previous ISR Plans, RIE has made many recommendations that include reclosers, breakers, and other protective devices, for which the protective coordination was determined during early engineering stages of project execution. Fault current levels and coordination issues are not a driver for any of the proposed investments.

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Division 1-26

Request:

Provide a copy of all protective coordination standards and protocols which serve as the basis for protective device installation and settings. This would include but is not limited to: use of a fuse save scheme, maximum fuse size applied; percent of setting above peak load current or cold load pickup percentage and so on. This information should spell out all the Company's protective coordination philosophies on relay application, recloser application, fuse application, and sectionalizer application.

Response:

The Company currently uses National Grid's protection coordination standards included as Attachment 1-26-1. PPL's protective coordination standards are also provided in Attachment DIV 1-26-2. Rhode Island Energy is currently reviewing the two standards and will be adopting the standards most applicable for Rhode Island for future protective device coordination efforts. There is substantial alignment between the two standards, but a few differences such as fuse save (PPL) versus fuse blow (National Grid) strategies exist. The differences will be carefully reviewed, but due to differences between the Pennsylvania and Rhode Island distribution system topology, a fuse save strategy is unlikely to be adopted.

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nationalgrid	**ENGINEERING DOCUMENT** **Guideline: Engineering and Asset Management**	Doc. # **GL.01.01.001** Page 1of 22
	Distribution Feeder Protection Guidelines Related to Feeder Breaker and Recloser Applications on Radial Distribution Circuits	Version 1.0 – 06/07/09

DOCUMENT CONTENTS

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1.0 INTRODUCTION

The procedures and criteria presented in this manual will provide guidance for the application of relay and control settings for feeder circuit breakers and reclosers on NATIONAL GRID's radial distribution feeders. These guidelines are applicable to distribution systems that are designed and constructed in accordance with the current NATIONAL GRID standards and design philosophies. There are many different legacy systems and equipment within NATIONAL GRID and the limitations and operation of these systems and equipment must be considered in the application of these guidelines.

2.0 OBJECTIVE OF OVERCURRENT PROTECTION

The protective schemes resulting from the application of the guidelines contained herein are intended to detect and clear all faults on the electric distribution system for the purpose of:

a. Maintaining a safe and reliable distribution system.
b. Minimizing the number of customers impacted for a given fault condition.
c. Protecting distribution equipment from damage due to fault current.
d. Aid in the locating of faults and thereby reducing restoration times.

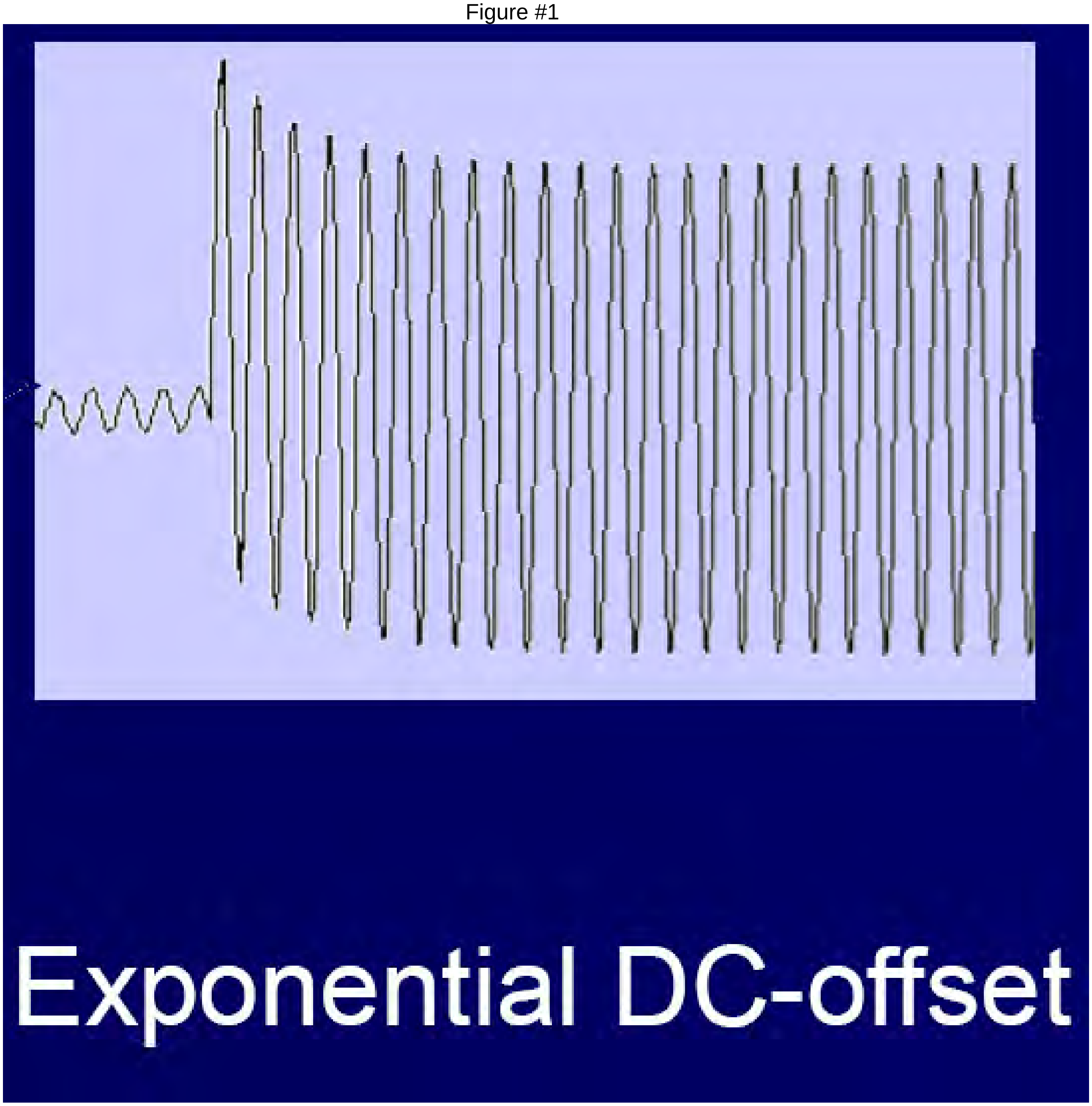
3.0 DEFINITION OF TERMS

Circuit Breaker
A sectionalizing device used to open or close an electric power circuit either during normal power system operation or during abnormal conditions. A circuit breaker serves in the course of normal system operation to energize or deenergize loads. During abnormal conditions, when excessive current develops, a circuit breaker opens to protect equipment and surroundings from possible damage due to excess current. These abnormal currents are usually the result of short circuits.

Coordinating Time Interval (CTI)
The differences in the operating times of series protective devices needed to ensure that coordination exists between the operation of these devices for expected fault conditions.

DC Offset
DC offset is a transient component of AC fault current resulting from the instantaneous change of fault current, refer to figure #1.

Figure #1

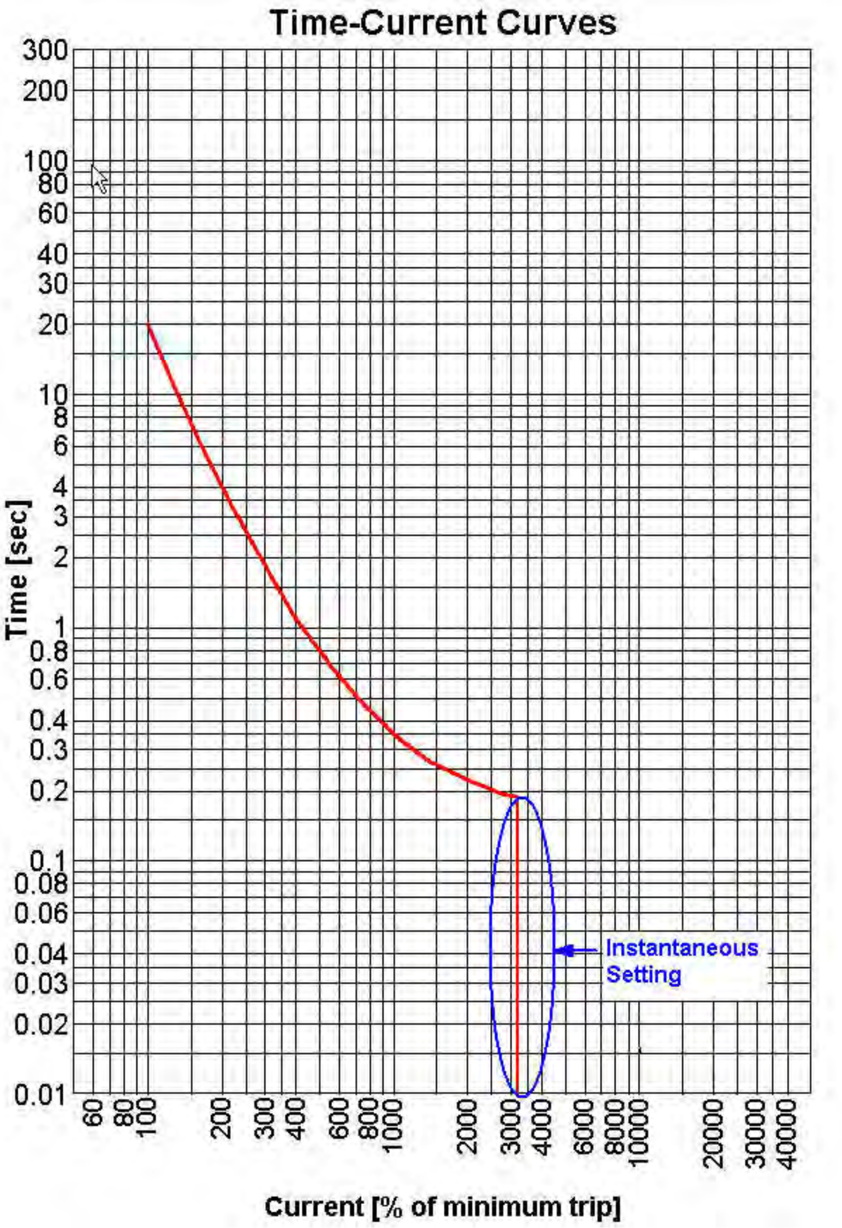


Dead Time/Band or Open Interval
In the reclosing cycle, a selectable time interval that will control how long the device will be open, following a trip operation, prior to the device issuing a reclose command.

Fuse Saving
Term used to describe the application of specific settings in a relayed protective device employing a fast trip with automatic reclosing that will allow it to operate fast enough to prevent a down stream fuse from operating/becoming damaged if a temporary fault, were to occur down stream of that fuse. In the application where a recloser is protected by a fuse, a fault on the downstream side of the fuse will result in the recloser tripping before the fuse link starts to melt. On subsequent reclose operations the recloser's protection settings will switch to a slower TOC setting and if the fault is still present, the fuse will clear before the recloser trips to lockout. This operation sequence is different than the preferred application, where the fuse will clear the fault before the recloser trips.

Instantaneous Settings
In general, instantaneous settings are used to limit equipment damage from high magnitude fault conditions. Unlike the typical time-overcurrent function, where the operating time of the device is inversely proportional to the magnitude of the current, a device utilizing the instantaneous function will essentially operate instantaneously for any current magnitude sensed by the device at, or above, the user selected instantaneous setting. Consequently, for any given fault equal to or great in magnitude than the value chosen for the instantaneous setting, coordination with down stream protective devices is generally not possible. As a practice, and to provide some level of coordination with down stream protective devices, instantaneous pickup settings can be derived by taking a value of 125% of the magnitude of an expected end of zone, bolted fault for a radial line for instantaneous elements that do not respond to dc offset. An instantaneous value of 150% of the magnitude of an expected end of zone, bolted fault is recommended if the instantaneous element is sensitive to DC offset. Generally, instantaneous functions are used in conjunction with time overcurrent functions where the instantaneous pickup value is set much higher than the time overcurrent pickup value, refer to figure #2.

Figure #2


Time-Current Curves
300
200
100
80
60
40
30
20
10
8
6
4
3
2
1
0.8
0.6
0.4
0.3
0.2
0.1
0.08
0.06
0.04
0.03
0.02
0.01
Time [sec]
60
80
100
200
300
400
600
800
1000
2000
3000
4000
6000
8000
10000
20000
30000
40000
Current [% of minimum trip]
Instantaneous Setting

Load Encroachment
The load encroachment function can be used in conjunction with overcurrent protection in those special cases where load current and fault current are similar in magnitude. The load encroachment function will typically block operation of the overcurrent protection under normal load conditions but allow operation of overcurrent protection under fault conditions by detecting the change in the impedance angle, power factor, of the line. Load impedance typically has a lower impedance angle (higher power factor) than fault impedance. The load encroachment relay can detect when this change in impedance angle occurs. The limitations with load encroachment are in those situations where load current has a very low power factor.

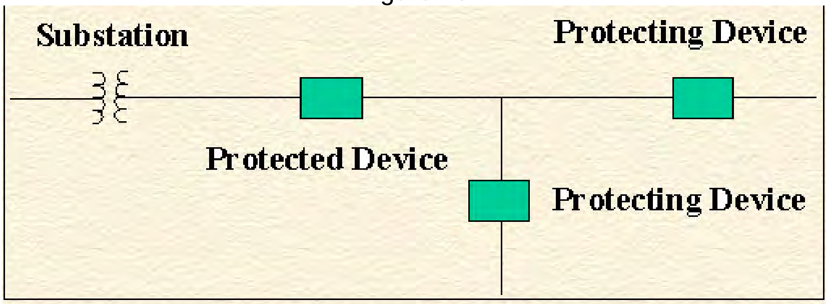
Overcurrent Protection
A protection scheme where a current sensing device will operate a breaker or recloser to interrupt fault current based upon an algorithm where the operating time of the protective device is generally inversely proportional to the magnitude of the sensed current. This function is often referred to as Time-Overcurrent Protection (TOC). The exception being when Instantaneous functions are used, see Instantaneous Settings.

Permanent Fault
Permanent faults are those which require human intervention, repairs, maintenance, or replacement of equipment, to clear before a circuit can be returned to service. Isolation of permanent faults can be accomplished by the operation of circuit breakers, reclosers, sectionalizers, and fuses.

Pickup
A selectable value that is the minimum magnitude of current that will allow a relayed protective device to operate

Protected and Protecting Device Coordination
Protection of an electrical circuit is accomplished through the coordinated application of series protective devices. Coordination exists between the protected (upstream) device and the protecting (downstream) device(s) when the protecting device clears a permanent or temporary fault before the protected device, which can be a recloser, breaker, or another fuse, operates, refer to figure #3

Figure #3



Protective Device Zone of Protection (Reach)
That section of an electrical circuit where a protective device can detect a fault and operate an interrupting device in order to isolate the faulted line section from the remainder of the circuit

Recloser
A self-contained relayed protective device that can be installed in an aerial, padmounted or substation pedestal arrangement. A recloser is usually made up an interrupting device, similar to a circuit breaker, controlled by multifunctional protective device.

Reclosing Function
The function by which a protective device will operate a breaker or recloser to isolate a faulted line section and remain open for a predetermined length of time, (Dead Time), then close again (Reclose) in an attempt to re-energize the that same line section under the presumption that the original fault was temporary in nature and has since cleared itself from the line. The protective device can be programmed to repeat this sequence a predetermined number of times (Operations/Shots to Lockout). If the fault is still present after the last programmed sequence of reclosing the protective device will trip and remain open (Trip to Lockout)

Reclosing Reset Time
A selectable time delay that is used by a recloser control or reclosing relay after a successful reclose to reset any accumulated trip operations. Reset after successful reclose occurs when the recloser or breaker is closed and no overcurrent is detected.

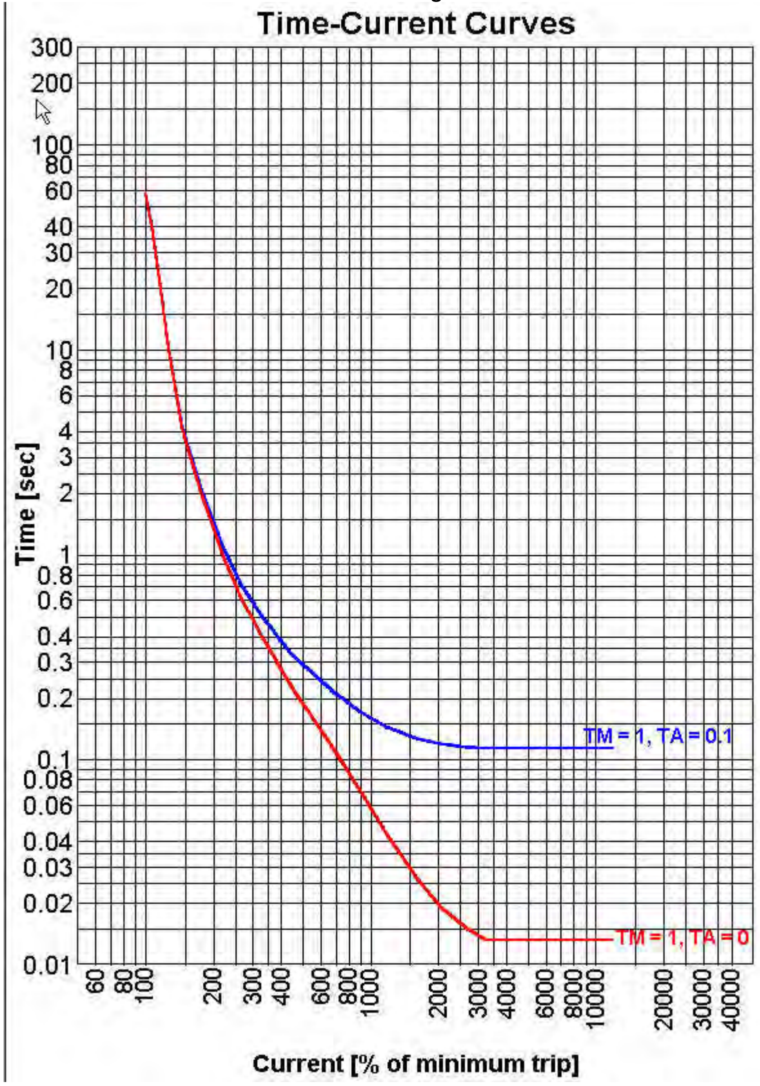
Relay
An electromagnetic or electronic device for remote or automatic control that is actuated by variation in conditions of an electric circuit and that operates in turn other devices (as switches, breaker, or reclosers) in the same or a different circuit.

Reset Time
The typical electromechanical relay will not reset its timing immediately after a fault is interrupted by a down stream device. There is usually a significant time needed for the timing disc to reset to its neutral position (Reset Time). Thus, when reclosing is employed by a down stream device such as a recloser, the recloser’s dead bands must be long enough and/or the number of reclose shots must be restricted to allow the upstream electromechanical relay to fully reset, otherwise, the relay will operate resulting in miscoordination. Reset times vary from manufacturer to manufacturer and relay model to model. The manufacturer’s literature should be reviewed to determine what that particular relay’s reset time is.

Temporary Fault
Fault conditions that are temporary in nature. They can be caused by momentary contacts with vegetation (a tree branch), contamination, lightning, even animal contact. Temporary faults generally clear themselves from electrical circuits in less than 1.0 seconds.

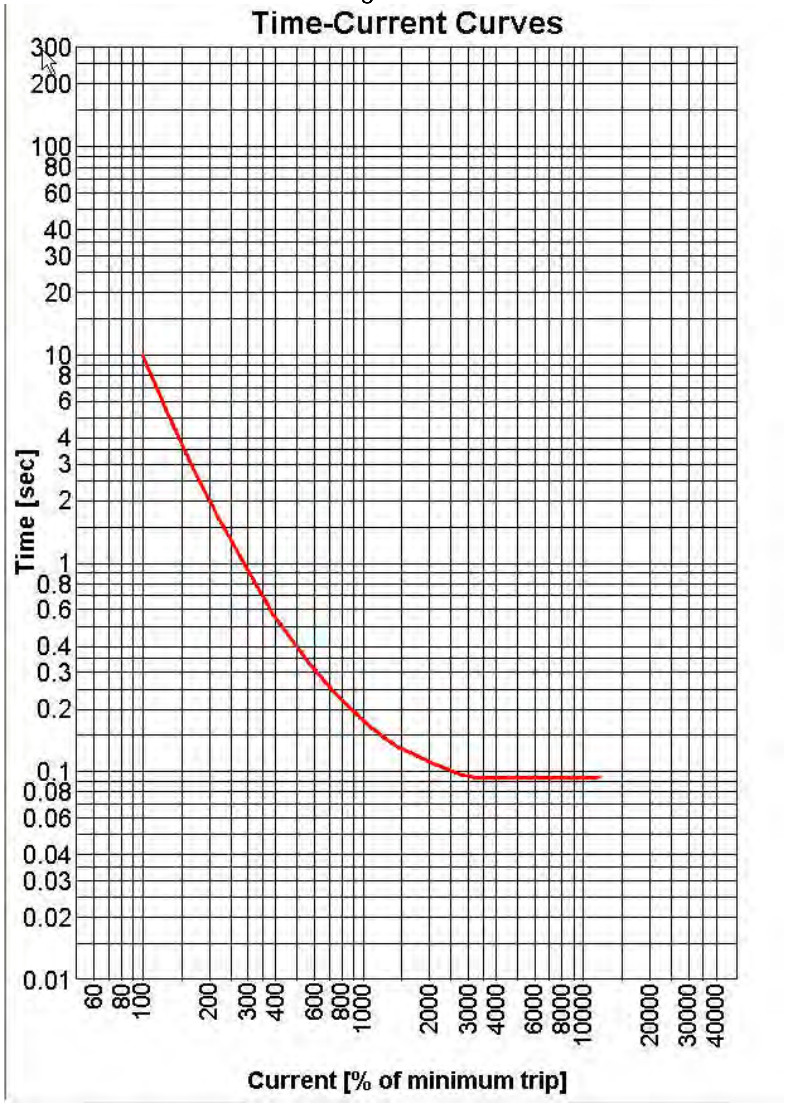
Time Adder
A selectable time delay where the trip time of a given TCC is shifted in time by the additional specified time. In contrast to the Time Multiplier, the Time Adder adds a constant delay time to the curve. For example if a curve had an operating time of 0.014 seconds for a specified current value and a 0.1sec time adder is used the new operating time would be 0.1140 seconds, refer to figure #4.

Figure #4



Time Current Characteristic (TCC)
The operating characteristic of the device represented as a log – log plot of the device's operating time versus current, where the operating time is generally inversely proportional, or some variation, to the magnitude of the current being sensed by the device. Time is plotted on the vertical axis and current magnitude is the horizontal axis, refer to figure #5.

Figure #5



Time Dial
A modifying function typically used on relay TCC curves, similar to the vertical TM function on recloser controls. The TCC curve is slowed down by shifting it upwards in Time Current space, refer to figure #6. Electromechanical relays have an actual adjustable time dial which governs how far the timing disk actually travels.

Figure #6

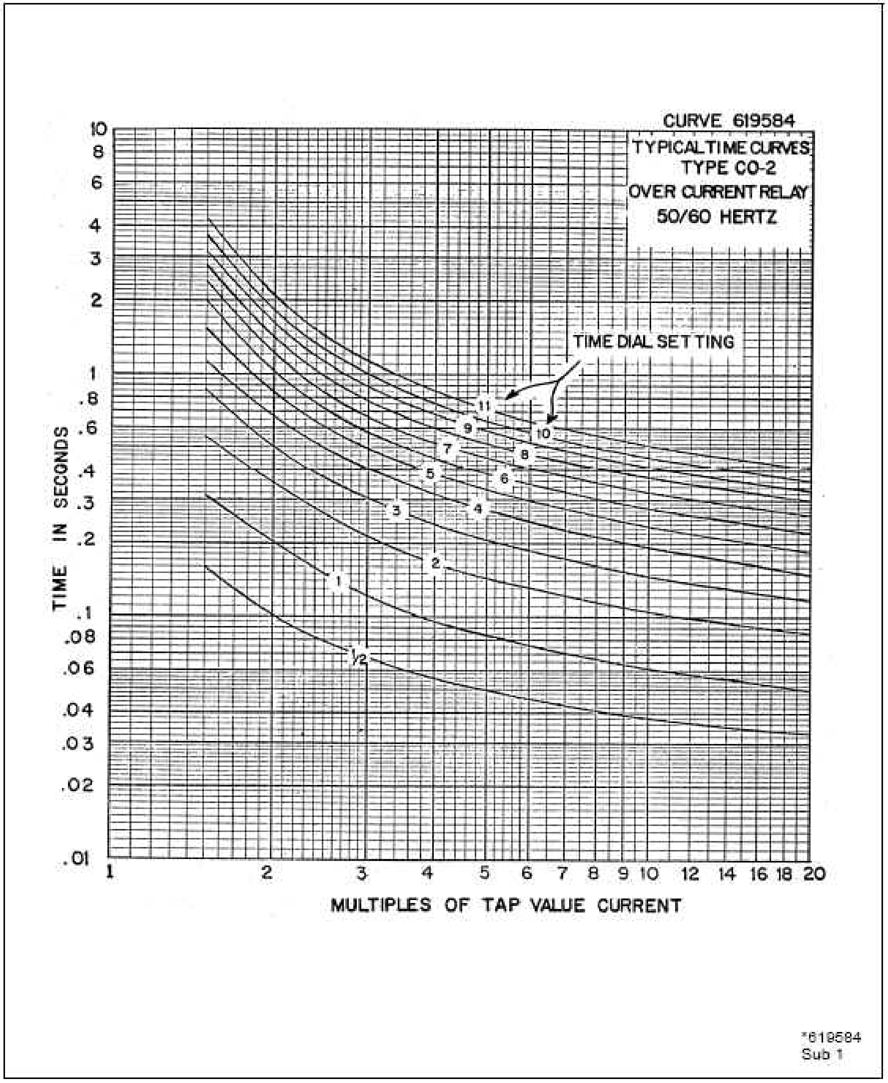


Figure 3: Typical Time Curve of the Type CO-2 Relay

Transformer Inrush Current

A transient phenomenon in which there occurs a short-duration inrush of magnetizing current when an unloaded, or loaded, distribution or power transformer is energized. The transformer's primary protective device must be capable of withstanding this inrush current without operating (or, in the case of certain types of fuses, without sustaining damage to their fusible elements). A conservative estimate of the integrated heating effect on the primary fuse as a result of this inrush current is roughly equivalent to a current defined by the following:

- 6 × nominal load current for one second;
- 12 × nominal load current for up to 0.1 seconds; and
- 25 × nominal load current for up to 0.01 seconds.

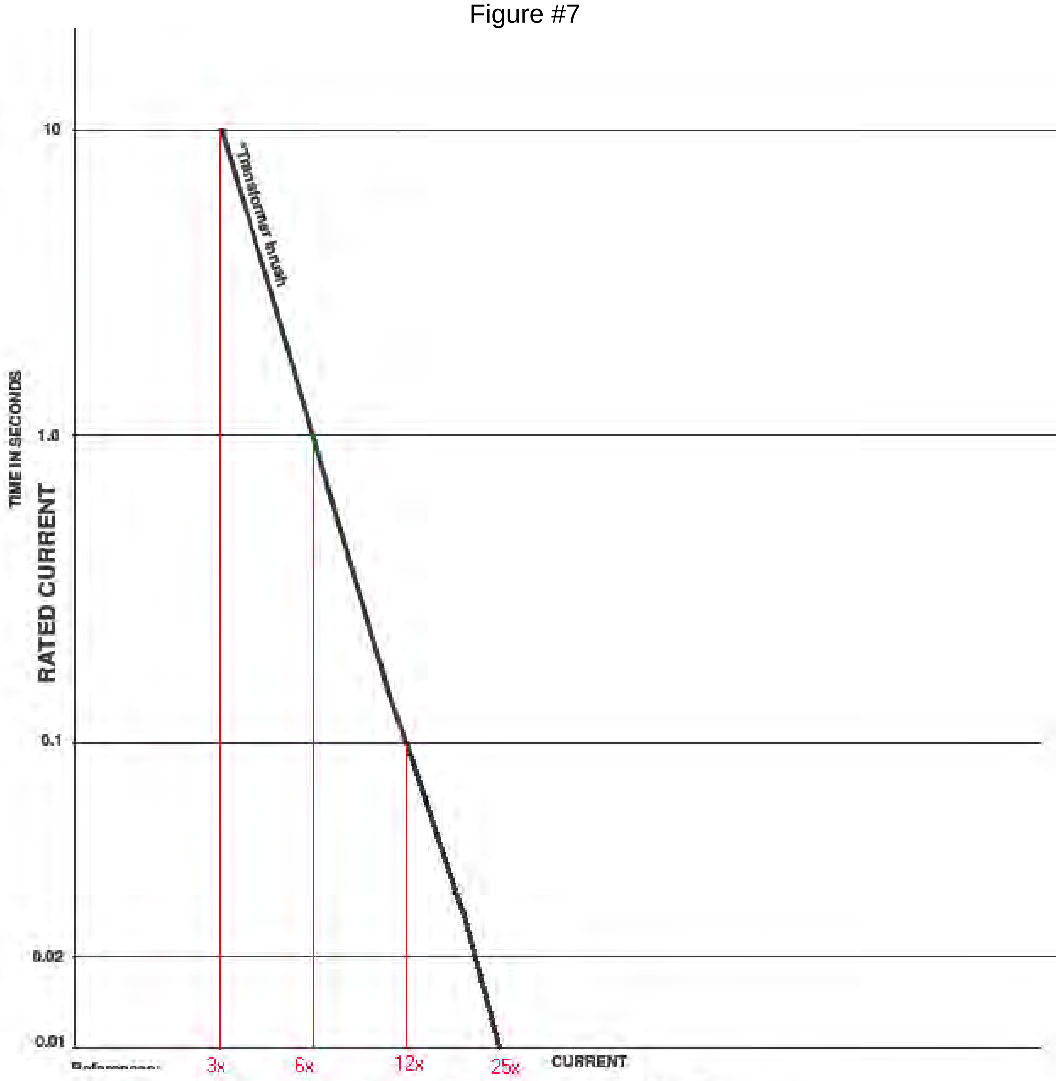
The inrush that occurs on any particular energization will depend, among other things, on the residual magnetism of the transformer core as well as the instantaneous voltage when the transformer is energized. Since these two parameters are unknown and uncontrollable, the proper relay setting or fuse must be selected to withstand the maximum inrush that can occur under worst-case energization. In the case of a fuse, the minimum-melting curve should be such that the fuse will not operate as a result of this magnetizing-inrush current.

To avoid a nuisance operation of the transformer-primary fuse or relayed protective device, it must be capable of withstanding the magnetizing-inrush current of the transformer superimposed on the transient overcurrent associated with picking up cold load current, the expected overload current associated with the total kVA connected. The time-integrated heating effect of the cold-load current profile on thermally responsive devices, such as fuses, is usually represented by the following equivalent multiples of transformer nominal rated load current:

- 3 × nominal load current for up to 10 seconds; and
- 2 × nominal load current for up to 15 minutes.

The transformer primary fuse or relayed protective device to must be able to withstand the combined magnetizing- and load-inrush current associated with an extended outage, refer to figure #7.

Figure #7

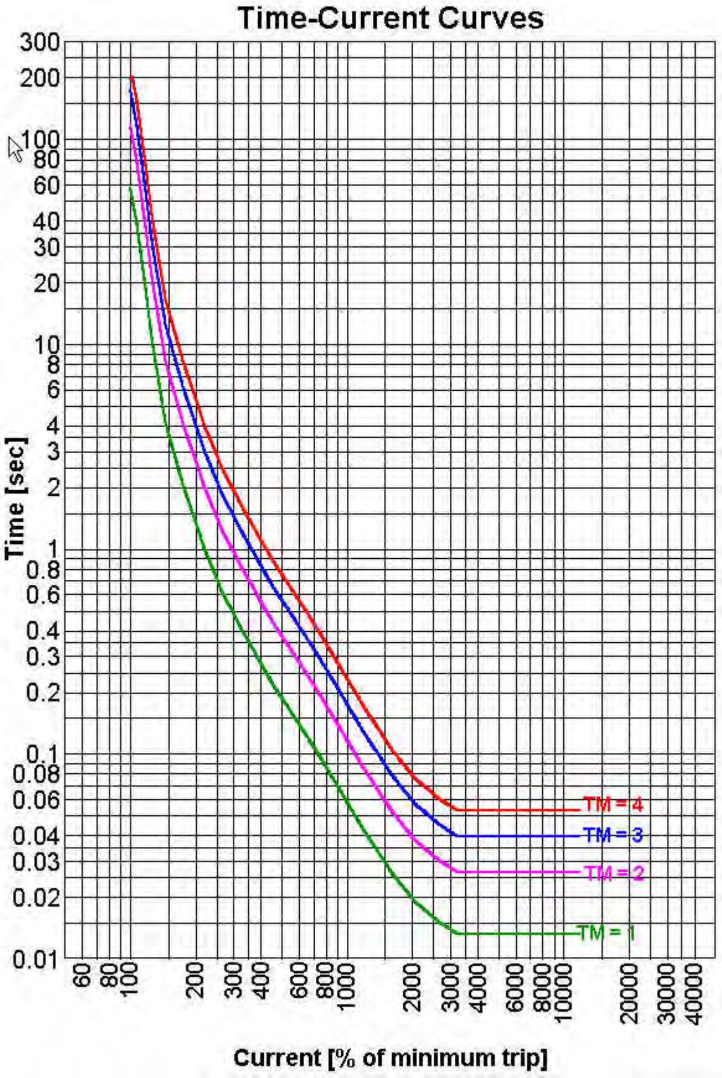


*Transformer inrush curve based on multiples of transformer (rated) full-load current: 25x, 12x, 6x, 3x, at 0.01, 0.1, 1.0, 10 seconds respectively.

Vertical Time Multiplier (TM)

A modifying function typically used on Recloser TCC curves, similar function to a Time Dial function on relays. The TCC curve is slowed down, shifted up in time by the specified multiplier, refer to figure #8. For example if a curve had an operating time of 0.4 seconds with a TM =1, for a specified current value, that same curve would have an operating time of 0.8 seconds, at the same specified current value, if TM=2.0.

Figure #8



4.0 GENERAL PRINCIPLES OF OVERCURRENT PROTECTION ON RADIAL CIRCUITS

Coordination of overcurrent protective devices is defined as their proper specification and arrangement in series along a distribution circuit so that they function to clear faults from the lines in accordance with a prearranged sequence of operation.

- The protecting device must clear a permanent or temporary fault before the protected device interrupts the circuit (fuse) or operates to lockout (relayed device)
- Outages caused by permanent faults must be restricted to the smallest section of the system for the shortest time

Relay controlled circuit breakers and reclosers are the devices addressed under these guidelines.

Main-Line Protection
Overcurrent protection is usually employed by the first protective device on a primary feeder in the form of a relayed circuit breaker or a power-class recloser located in the substation. If portions of the main-line and long laterals extend beyond the zone of protection of the relay controlled breaker or recloser at the substation, additional overcurrent protective equipment such as fuses or reclosers should be installed in series on the main-line to ensure that any bolted faults that can possibly occur on the line can be detected and isolated in less than a 1.0 seconds.

Utilizing Reclosing for Temporary Fault Protection
On overhead line circuits the majority of the faults that may develop are temporary in nature. For this reason reclosing is generally utilized on these lines in an attempt to try and clear the temporary fault, and reenergize the line, thus avoiding a permanent outage. Reclosing is not to be utilized on completely underground circuits or where more than 50% of the circuit main line is underground mainline since cable faults, by their very nature, are rarely temporary. In many cases circuits are comprised of a combination of both large overhead and UG mainline sections. In those cases where a large underground section of mainline does rise up and transition to overhead, line reclosers can be used to provide overcurrent protection and reclosing on the overhead section of mainline. Likewise, on those circuits where a large underground mainline section originates off a large overhead section of line, a recloser can be used to provide overcurrent protection without reclosing on the underground line section while reclosing is employed on the feeder breaker.

Instantaneous Settings
The use of the Instantaneous Setting Function is a very limited application due to the fact that coordination with down stream protective devices is usually not possible. The application of instantaneous settings is basically limited to underground circuits that are express in nature and where the expected fault current magnitudes are very high. Specifically the instantaneous application is warranted when a protective device using typical time-overcurrent curves alone will not operate fast enough to isolate the faulted section before critical equipment on the line is damaged. Generally, equipment damage curves are reviewed to determine this. Typical cable damage curves are derived from the equation $T = (k\ (A/I))^2$, where A is the area in circular mils, T is the time, I is the current, and k is a constant. In the case of new mainline underground construction, it is usually the solid dielectric cable in conduit, where the limiting element is the shield wire, our current standard being 18 strands of #14 Cu. The assumption is that the neutral wires are connected together in every manhole, and that a

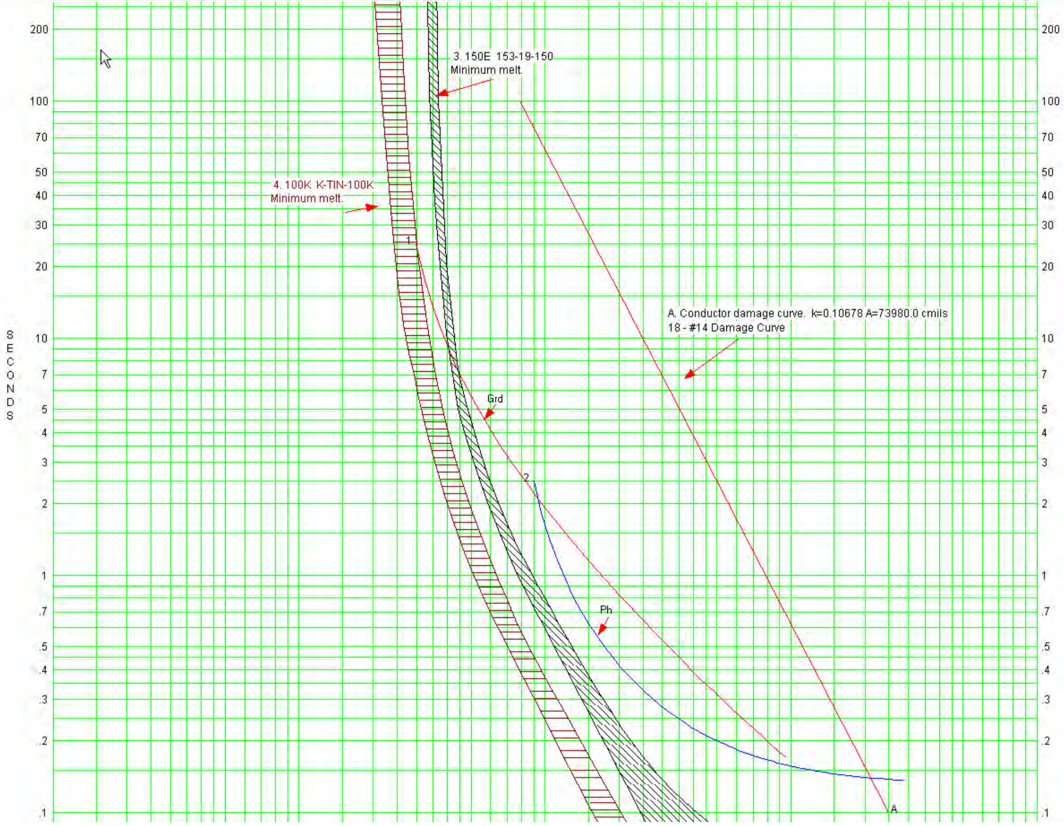
cable section will be replaced after a fault. The shield needs to survive long enough to allow the protective relaying to operate, but cable damage in the faulted section is allowed. The shield wires are limited to withstand the following current magnitudes over time before they are damaged.

Shield Wire - 18 strands of #14 Cu

Seconds	Cycles	Current kA
0.08	5	27.3
0.167	10	19.3
0.5	30	11.2
1.0	60	7.9

Figure 9 illustrates the resulting conductor damage curve plotted against fuse and relay TCCs.

Figure 9



Due to the significant volume of varied legacy underground cable in service, the appropriate equipment damage curves should be reviewed whenever fault current magnitudes exceed 8kA.

In those cases where instantaneous tripping is warranted and minimal coordination is to be maintained with down stream devices, as a practice, instantaneous pickup settings can be derived by taking a value of 125% (150% for clapper or plunger type inst) of the magnitude of an expected end of zone, bolted fault, in addition, reclosing is not to be utilized.

When relayed protective devices, such as reclosers, are added to main line down stream of substation relays employing instantaneous settings, and it is desirable to continue to utilize the instantaneous function on the line section between the recloser location and the instantaneous relay, the recommended practice is to set the instantaneous pickup settings to a value of 125% (150% for clapper or plunger type inst) of the magnitude of an expected, bolted fault at the recloser location. This will allow the Time Over Current element to take precedence over the Instantaneous element, for any fault that may occur down stream of the recloser. The recloser can be coordinated with this TOC setting to ensure that the recloser will operate and isolate a fault down stream of it with out causing the feeder's instantaneous element to trip the substation breaker. If maintaining instantaneous the setting is not desired, disable, or set the instantaneous pickup setting higher that than the largest magnitude of expected fault current.

Fuse Saving
Choosing TCC curves and settings to allow fuse saving is not a recommend practice as it can result in excessive momentary interruptions for all customers downstream of that recloser or breaker.

The use of saving is discouraged and its use is limited to pre-approved special situations.
In those special approved situations, in order for fuse saving to be successful, all of the following criteria must be met:

- Only in areas where line reclosers are protecting remotely accessible single phase line sections, where fused single phase circuit branches (65K fuse or size greater fuse) experience a high frequency of operation due to temporary faults.
- In locations beyond the protecting fuses, the fault current must not exceed 1,180amps, otherwise, the recloser cannot clear the fault fast enough without damaging the fuse.

Fuse saving should never be used on substation feeder breakers/reclosers, otherwise a significant number of customers will be exposed to nuisance momentary outages.

Load Encroachment
Load Encroachment is applied on distribution feeders in conjunction with time overcurrent protection to maintain sensitivity for detection of end-of-feeder faults in applications where load growth has exceeded minimum fault detection levels. Load encroachment allows phase overcurrent elements to be set independent of load levels or thermal ratings. This enables phase overcurrent elements to be set with pick values that may otherwise thermally limit that feeder or line section and still allow adequate fault sensitivity under high load conditions, refer to National Grid Doc #PR.10.00.00 "Application Guide : Protection – Feeder Load Encroachment"

Recommended Load Encroachment settings for distribution feeders using SEL351 or 651R relays/recloser controls:

PLAF = 32 degrees

NLAF = -90
PLAR = 95
NLAR = 270

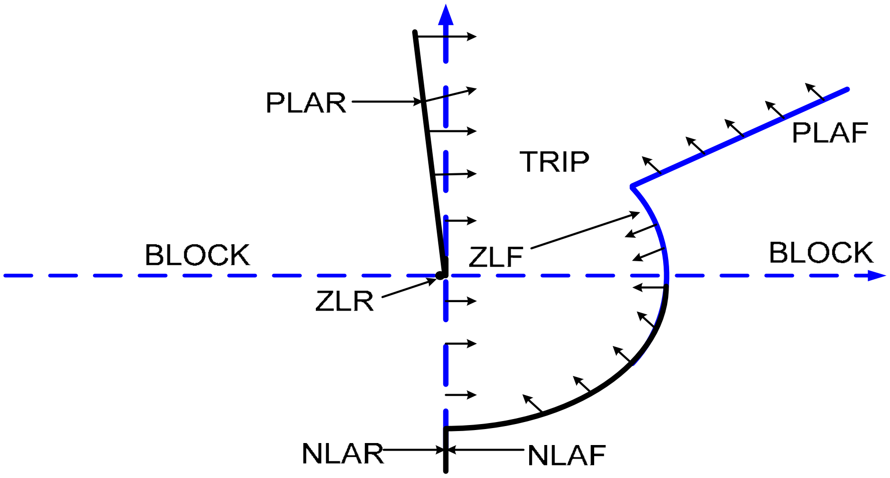
$$ZLF = \frac{.85 \times 1000 \times KV_{LG}}{2 \times FeederRating_{Amps} \times 1.15}(\Pr iOhms) \times \frac{CTR}{PTR}(SecOhms)$$

ZLR = .1 min setting (sec-ohms)

Where:

PLAF = Maximum Positive Load Angle Forward (-90 to +90 deg)
NLAF = Maximum Negative Load Angle Forward (-90 to +90 deg)
PLAR = Maximum Positive Load Angle Reverse (+90 to +270 deg)
NLAR = Maximum Negative Load Angle Reverse (+90 to +270 deg)
ZLF = Forward minimum load impedance (.05 – 64 ohms-sec)
ZLR = Reverse minimum load impedance (.05 – 64 ohms-sec)

Figure #10



Under normal load conditions operation of the time overcurrent phase element is blocked by the load encroachment element. When a fault does occur, the load angle swings from the blocked zone into the trip zone and the time over current element is no longer blocked thereby allowing the breaker or recloser to operate to clear the fault, refer to figure #10.

5.0 GUIDELINES FOR DETERMINING TIME OVERCURRENT SETTINGS FOR CIRCUIT BREAKERS AND RECLOSERS ON RADIAL CIRCUITS PROTECTING SECTIONS OF FEEDER MAIN LINE

5.1 When two or more relayed protective deices are arranged in series on the same circuit, the TCC pickup value chosen for a protection element (Phase or Ground) on the upstream device must always be greater in magnitude that the pickup value for the corresponding TCC protection element (Phase or Ground) on the downstream device.

5.2 Phase pickup settings are not intended to be selected to prevent thermal overload of a limiting element or circuit.

5.2.1 The phase setting must be able to coordinate with the largest down stream fuse and/or the phase setting of any relayed down stream protective device.

5.2.2 At a minimum, the phase setting shall coordinate with a 140K fuse.

5.2.3 As a general rule, the phase setting must be able to clear an end of zone bolted 3 phase fault in less than a second.

5.2.4 Ideally, substation relay/recloser phase pickup settings should be selected to be at least greater than 115% of the current rating of the circuit’s limiting element, (check summer normal rating or where applicable winter normal rating), found in that protective device’s zone of protection.

5.2.5 Line recloser Phase pickup settings shall be at least 115% of the expected peak loading for the line section in the recloser’s zone of protection.
5.2.6 Phase settings must be able to carry inrush current (includes magnetizing and cold load inrush).

5.3 Ground settings for a substation relay/recloser must fully coordinate with any downstream settings of any relayed protective device, and a 100K fuse.

5.3.1 If fuses larger than 100K are present down stream, and, if system parameters allow, coordination with that fuse can be attempted, for a bolted fault, within that fuse’s zone of protection.

5.3.2 As a general rule, a bolted end of zone ground fault should be cleared less than a second. This criteria can be met through activation of either the Ground or the Phase Element.

5.4 Line recloser ground settings must coordinate with the ground characteristics of any downstream protective devices, (another recloser or reclosers), and with a 100K fuse.

5.4.1 In applications where reclosing is utilized, it is acceptable to have the relay ground TCC to fall between the fuse's minimum melt and total clearing characteristics, this will allow the fuse to clear a fault down stream of it during the breaker or recloser's reclose cycle before the recloser goes to lockout..

5.4.2 When fuses larger than 100K are present on the line down stream of the recloser, an attempt should be made to coordinate for bolted fault within that fuse's zone of protection.

5.5 To ensure adequate fault sensitivity, a bolted end of line fault, at the end of the protective device's zone of protection, (reach), should be cleared in less than a second.

5.5.1 In many areas there will be circuits where fault magnitudes are such that this criteria will be difficult to meet (for example, when the fault current magnitude is less than 500amps, a 100K fuse will not clear a fault in less than 1.0 second). In such instances consideration should be given to additional mainline protection, or the use of enhanced overcurrent protection, such as load encroachment settings should be considered. Consequently, good engineering judgment must come into play to determine what is feasible and practical.

5.6 The protective device must be able to clear the maximum fault available without damage to itself (interrupting rating), and before damage occurs to equipment.

5.7 The recommended coordinating time interval (CTI) to ensure coordination between series protective devices is as follows:

5.7.1 Electromechanical relay to Electromechanical relay – 0.4 seconds
0.3 seconds is considered adequate assuming breaker time does not exceed 0.1 seconds

5.7.2 Electromechanical relay to electronic device - 0.3 seconds
Electromechanical device to fuse – 0.2 seconds

5.7.3 Electronic device to electronic device – 0.2 seconds

5.7.4 Electronic device to fuse – 0.1 seconds

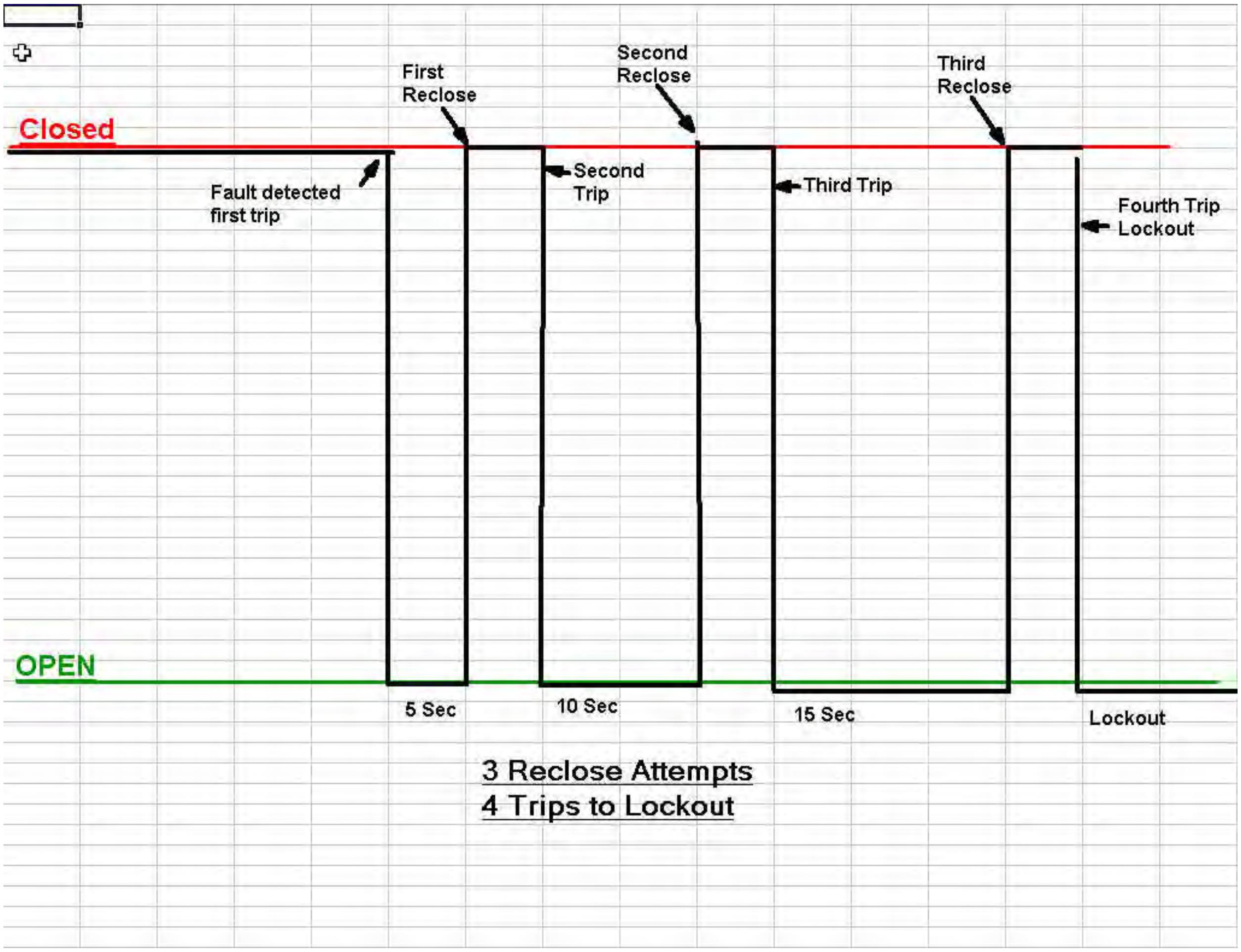
5.7.5 Fuse to fuse – 0.1 seconds

5.8 Substation feeder relay/recloser settings and line recloser settings are the responsibility of the Network Asset Planning Department. The System Protection Department shall review and approve any requested substation relay/recloser settings before they are issued to the appropriate group for implementation.

6.0 GUIDELINES FOR RECLOSING

Generally, reclosing shall be used on all overhead main line conductors. Two reclose attempts (3 shots to lockout) are recommended to be used for substation reclosing and three reclose attempts (four trips to Lockout) are generally recommended for line reclosers, refer to figure #11.

Figure #11



Consideration may be given to a fourth reclose attempt for line reclosers on feeders in remote rural areas. Typically, the open time for the first open interval should be 5 seconds, 10 seconds for the second, and 15 for the third and fourth open intervals. Reclosing reset time is recommended at 60 seconds.

These reclose and reclosing reset times can be applied to most electronic or microprocessor type protective devices. Certain older electronic recloser controls have limitations on the available settings due to the discreet plug in modules that are used. Any electromechanical protective relays in the circuit require consideration of that device’s reset time and hence much longer dead bands may be required to allow the relays to fully reset. Also, electromechanical reclosing relays will have setting limitations due to the nature of their construction and operation.

7.0 ALTERNATE SETTINGS PROFILE

Certain microprocessor based protective devices allow the user to program in multiple setting profiles that can be used for special applications. An alternate settings profile can be employed to prevent tripping of a protective device during certain emergency contingency situations. In such an application, the phase pickup value is recommended to be at least **115% of the short time emergency** rating on the circuit. Generally reclosing will not be employed. The responsibility for activating these settings and subsequently returning to the normal settings will reside with the Regional Control Centers providing the units are on EMS. Coordination with other series protective devices will be compromised when these settings are enabled.

8.0 REVISION HISTORY

Version	Date	Description of Revision
1.0	6/07/09	Initial version of document. Based on and supersedes NE EDP-DIV-2 “Settings for Distribution Feeder Overcurrent Protective Devices”, Rev.1 dated 11/16/98.

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Distribution Protection Department

Distribution Protection Philosophy

Standard No.	1-003
Revision	04
Effective Date	04.03.2017
Valid Until	06.01.2021
Sheet	1 of 49

Revision Notes

Revision	Date	Author	Approved By	Comments
01	01.04.2016	Mychal Kistler		*Document creation*
02	05.13.2016	Mychal Kistler		*Added SEL sections on relay function and logic*
03	08.02.2016	Mychal Kistler		*Minor corrections, added end of line device method*
04	09.15.2016	Mychal Kistler		*Added examples*

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1. Executive Summary

1.1 Abstract

A. Define a set of rules to improve service performance to customers through optimization of automatic line sectionalizing.

1.2 Automatic sectionalizing philosophy guidelines

A. A set of guiding principles for circuit optimization can be found in **Table 1.1**. These principles are meant to allow flexibility in the method of developing automatic sectionalizing while achieving a consistent result across the distribution system.

Sectionalizing Principle	Purpose	Performance Indicator
Isolate permanent faults with the nearest upstream automatic sectionalizing device.	Interrupt the fewest amounts of customers possible.	Reliability
	Reduce the number of operations per device by reducing the number of devices tripping.	Maintenance
Clear faults in the fastest reasonable time.	Reduce maintenance costs by limiting equipment damage caused by heat generated during faults.	Maintenance
	Reduce voltage dip induced momentaries caused by slow clearing.	Reliability
Implement hot line tag on capable devices.	Protect crews performing hot line work by reducing incident energy to the lowest amount possible.	Safety
Save fuses for transient faults.	The upstream automatic sectionalizing device should operate to protect line fuses from operating during transient faults.	Maintenance / Reliability
	Where the fuse cannot be saved the upstream device should not operate.	Reliability

Table 1.1 Sectionalizing Principles

1.3 Impact on key performance indicators

A. The automatic sectionalizing guidelines provide a circuit optimization strategy to improve reliability performance indicators and reduce maintenance costs by reducing device wear and tear, while maintaining at minimum a baseline of industry standard protection.

B. Properly set and coordinated protective schemes offer many benefits to key performance indicators, which are detailed in subsequent discussion points in this section.

C. **Scheme Implementation:** The effect on key performance indicators applies to all *new* protective schemes. While all efforts are made to revise older schemes and bring them up to current standards it is not always possible to replace existing equipment or revisit existing settings in a timely manner.

D. **SAIFI:** Proper coordination of protective devices reduces SAIFI by reducing the number of customer interruptions – when the desired protective device trips to isolate a system disturbance (that is, the device closest to the fault) – the number of customers experiencing an outage caused by the interruption is reduced.

$$SAIFI = \frac{\sum Total\ Number\ of\ Customer\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

E. **SAIDI:** Proper coordination of protective devices reduces SAIDI by reducing the number of customer interruptions – fewer customers experiencing an outage will reduce the sum of the “Customer Interruption Durations.”

$$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customers\ Served}$$

F. **CAIDI:** Proper coordination of protective devices reduces CAIDI by reducing the total number of customers affected by an interruption – when the device closest to the system disturbance isolates the fault less customers will experience the interruption, and the sum of the “Customer Interruption Durations” will also be reduced.

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customer\ Interruptions}$$

G. **MAIFI:** Eliminating fuse savings at the feeder CB relay improves MAIFI be preventing the CB from tripping for faults that will also be cleared by a fuse, reducing the number of customers that would have experienced a momentary when a permanent outage will also occur. Other performance indicators should not be affected because the fuse was likely to have operated anyway, causing a permanent outage.

Reducing the number of devices that trip to save a fuse to one will provide only minor reductions to MAIFI, but will prevent misoperations that can occur when multiple devices trip for the same fault.

$$MAIFI = \frac{\sum Total\ Number\ of\ Custmer\ Momentary\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

1.4 Summary of automatic sectionalizing strategy

A. Each distribution feeder shall be equipped with a circuit breaker controlled by a protective relay or recloser operated in protective mode. The protective elements shall be set in accordance with the guidelines described in this document and the distribution protection standards. At a minimum protection will include, but is not limited to: overcurrent, hot line tag and reclosing.

B. Automatic line sectionalizing devices, which include: reclosers, sectionalizers and fuses, shall be set in similar fashion to the feeder protective device. The placement of line sectionalizing devices shall be decided by distribution planning, reliability engineering or distribution design with consultation from distribution protection. To maximize the efficiency of the system all devices shall have settings that comply with the automatic sectionalizing guidelines described in this document.

C. Overcurrent protection is the preferred method to detect and isolate faults on the distribution system because it provides accurate fault detection for reasonable cost and requires a moderate level of setting calculation complexity. Overcurrent detects faults downstream from the device point of origin, while the device is normally sourced, and initiates tripping instantaneously or by time-delayed curves where the clearing is inversely proportional to the current. The clearing times are optimized to provide maximum coordination with upstream protective devices (substation or transmission sectionalizing device at the feeder CB, feeder CB or other reclosers for line devices) and downstream automatic sectionalizing devices.

D. Reclosing is provided on circuit breakers and reclosers and is utilized to automatically close the device after a protective trip is initiated. Given that an estimated 85%[1] of faults are transient this relieves the system operator or line crew from having to manually close the device after each transient operation. Reclosing is limited to a maximum of three operations because the chance of holding on the third and subsequent trips is less than 1%. Reclosing attempts may be reduced or blocked due to excessive lengths of downstream cable or excessive fault magnitudes that could damage equipment, or in rare cases for coordination with other line devices.

E. Hot line tag is provided for crew safety while hot line work is performed within the minimum approach distance (MAD). OSHA requires that reasonable estimates of incident energy be made

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[1] IEEE C37.104-2012

for crews performing live line work within the MAD to establish the required personal protective equipment (PPE) such that no clothing shall melt and damage the workers skin during a flash. Hot line tag makes all tripping instantaneous and blocks reclosing, thus reducing the incident energy to the minimum and potentially eliminating the need for additional PPE that could prove hazardous in certain working conditions.

F. Fuse savings is provided because of the estimated 85% transient faults. While not all transient faults are past fuses, without fuse savings those transient faults that are past fuses would result in a permanent outage, increasing duration of outage and circuit restoration times when the transient could have been cleared and automatically restored by the upstream line device.

G. In accordance with the guidelines provided in this document all automatic sectionalizing devices shall be coordinated to limit interruptions to the fewest amount of customers possible and to reduce tripping to the fewest devices possible. All efforts will be made to limit the overreach of the protective zones where coordination cannot be achieved.

H. In general, the last device before a normally point will be made protective so that some form of line protection is provided during a transfer.

I. Detailed descriptions of operation for each automatic sectionalizing device element can be found in subsequent sections.

2. Definition of Schemes

2.1 Explanation of protective zone

A. A protective zone is defined as the circuit downstream from the protective device while it is normally sourced. The limit of the protective zone is the next downstream protective automatic sectionalizing device, with the exception of fuses due to the fuse savings scheme. See **Figure 2.1** for an illustration.

B. The limit of protection is the minimum line-end fault current within the device's zone of protection – i.e. the device must be able to detect all unrestricted faults within its zone. A variable percent margin of error is added to line-end faults to account for some fault restriction, inaccuracy in metering equipment and inaccuracy in system models. IEEE recommends a minimum of 150%[2] safety margin on line-end faults.

C. Due to circuit configuration there are instances where the placement of automatic sectionalizing devices on the distribution system does not allow for a clear "next downstream" device. In these instances the protective zones may overlap and multiple devices could operate for transient

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[2] IEEE Std C37.230-2007

faults. The standards provide guidelines to limit multiple devices from going to lockout for permanent faults wherever this coordination is possible.

D. Further, there are locations where the 69 KV zone distance protection will overreach substation power transformers and portions of the 12 KV line. Where this occurs the feeder relay instantaneous overcurrent must be set to clear faults faster than the zone distance relays and detect faults 20% further than the zone distance relays in all cases. It is not desirable to operate transmission protection for 12 KV faults. Therefore, at these locations the overlapping of protective zones cannot be avoided and multiple line devices may operate to lockout for permanent faults. See **Figure 2.2** for an illustration.

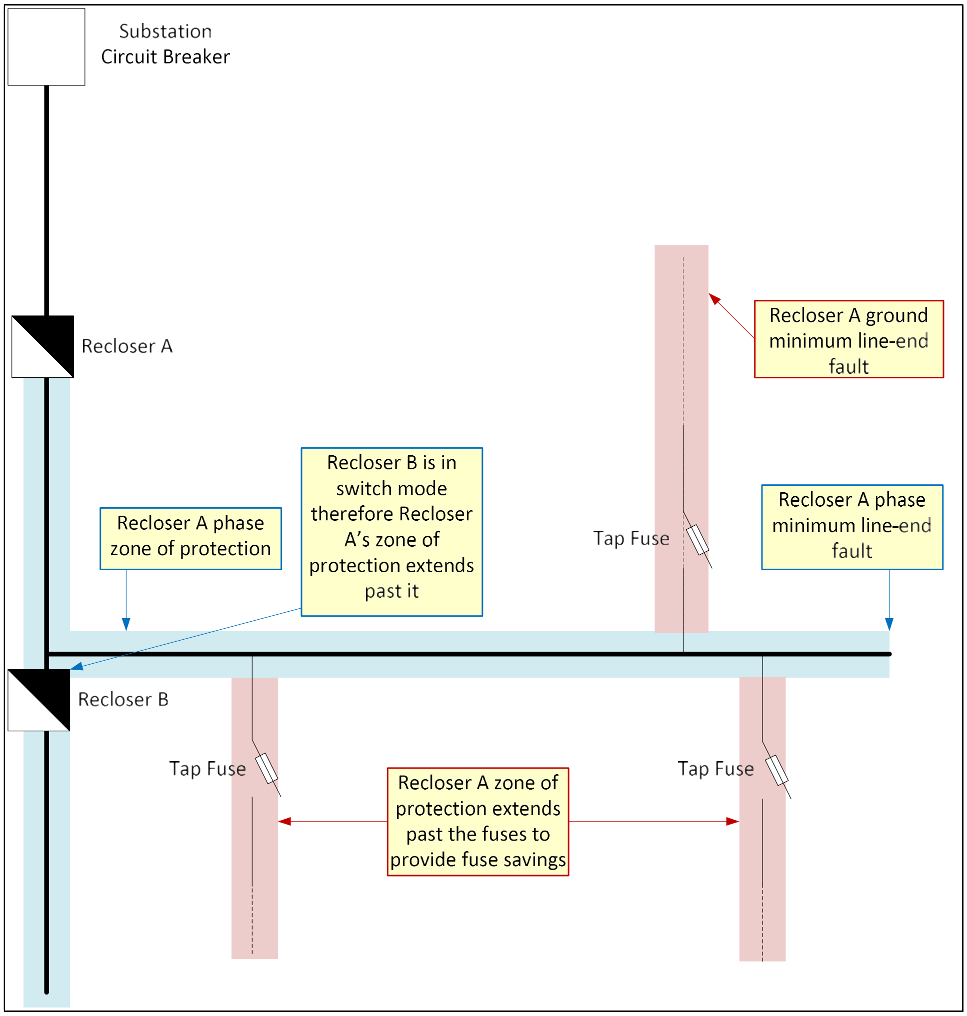


Figure 2-1 Illustration of protective zones

E. Finally, at substations where 69 KV fuses are used to protect the power transformer the 69 KV fuse zone of protection will overreach the 12 KV line for considerable distance. Since it is not desirable to operate the 69 KV fuses for line faults the feeder CB must operate faster than the fuses for all line faults. This is accomplished with instantaneous overcurrent elements. As with the zone distance overreach, the overlap of the protective zones cannot be avoided and therefore multiple line devices may operate for permanent faults. See **Figure 2.3** for an illustration.

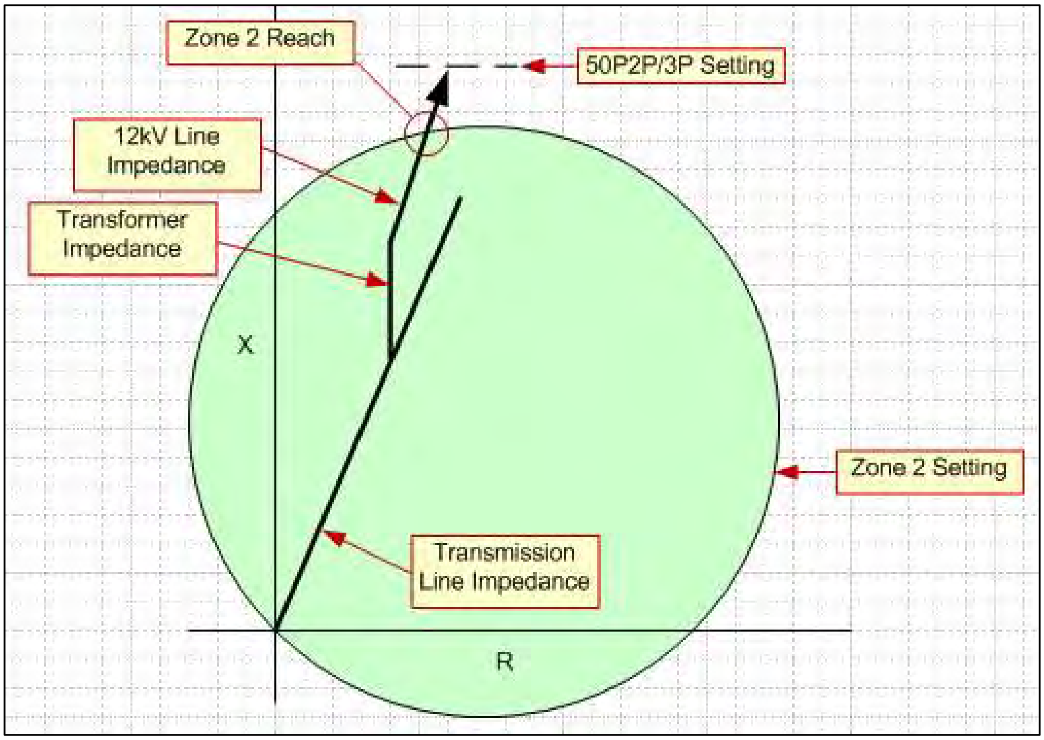


Figure 2-2 Example of Zone Distance Overreach

1. The zone 2 reach is set at 125% of the transmission line impedance.
2. The zone 2 reach is the area inside the circle.
3. In this example the 69/12kV transformer falls inside the circle, as does some length of 12kV line impedance.
4. The point where the 12kV line crosses the arc of the zone 2 circle is the extent of the zone 2 reach onto the 12kV system.
5. The 50P2P/3P setting is determined at 90% of the phase-to-phase fault magnitude at that location, +10% further reach of the zone 2.

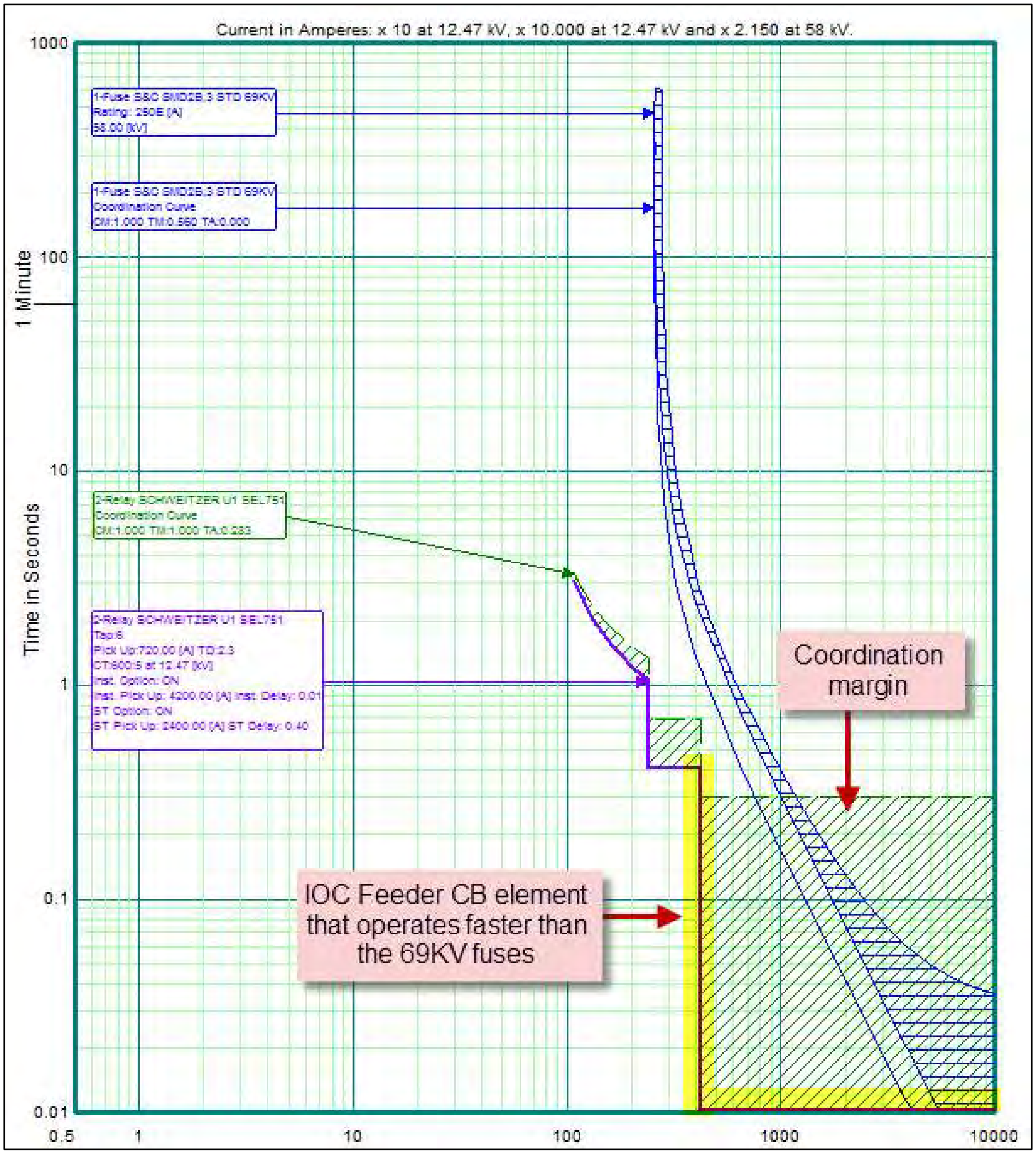


Figure 2-3 Example TCC Graph for 69 KV Fuse Coordination

2.1 Explanation of overcurrent protection and coordination

A. Overcurrent protection uses input current from current transformers (CTs) mounted in the device bushings that meter the line current; the metered current is then compared to the calculated setting and if the current exceeds the setting trip-timing begins. When the timer expires a trip command is sent to the recloser or circuit breaker. See **Figure 2.4** for an example of how the internal relay decision logic works for an overcurrent element.

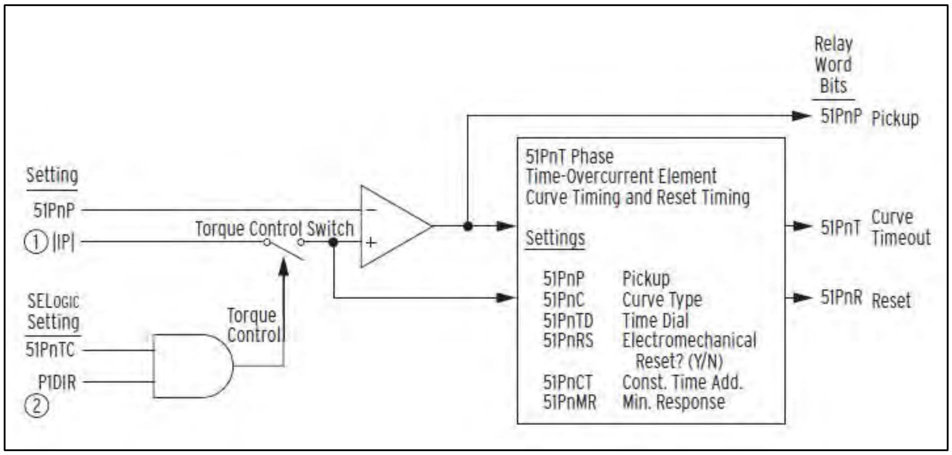
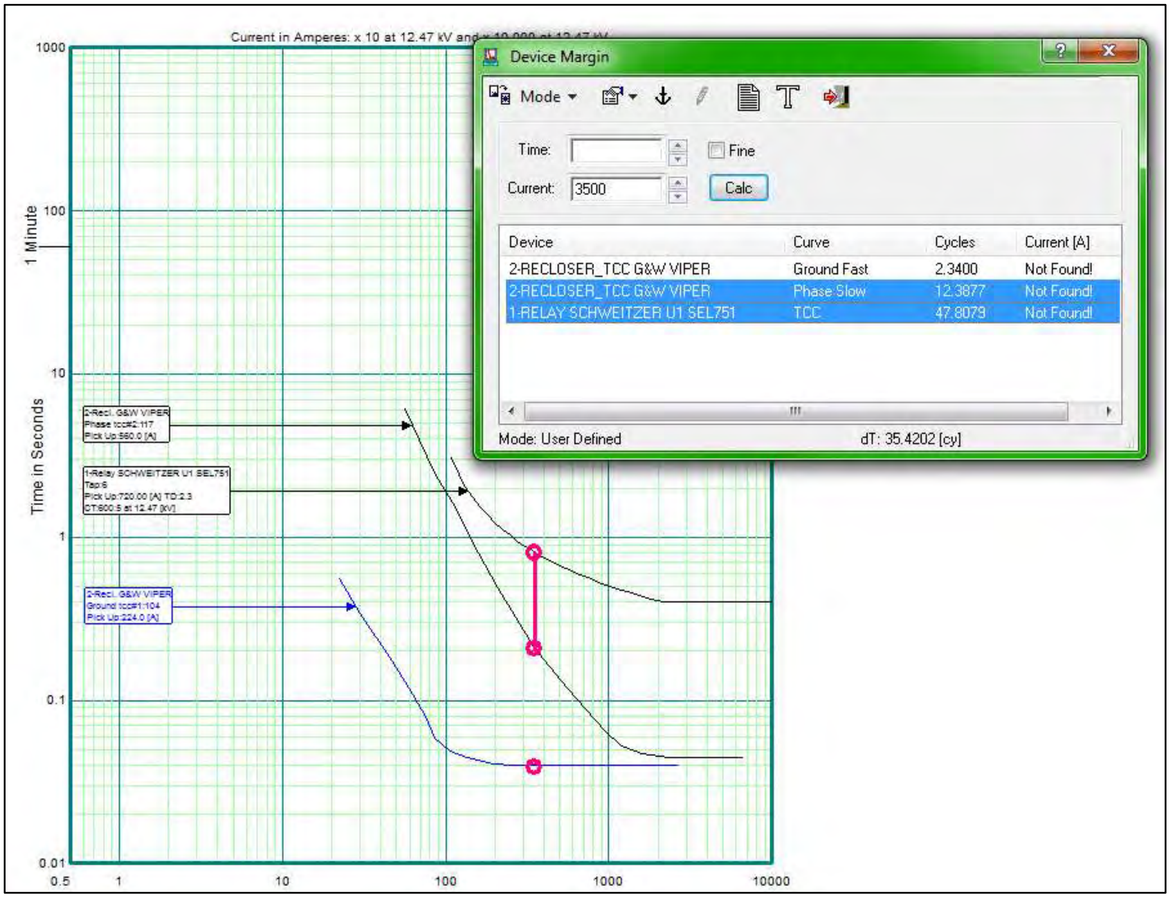


Figure 2-4 Example Time Overcurrent Relay Logic

B. The overcurrent pickup setting is calculated to be as sensitive as possible while still allowing for maximum line loading. This ensures the protective device will protect line equipment and detect as many restricted faults as possible while not being load limiting. These calculations may not be valid while the device is abnormally sourced and it is understood that overcurrent settings are developed for “system normal” conditions only.

C. Instantaneous overcurrent (IOC) elements will detect faults and send a trip command in approximately 1 cycle; therefore it is not possible to coordinate IOC elements. It is understood that where IOC protective zones overlap multiple devices will operate for the same fault. This is not desirable but is an unavoidable byproduct of overcurrent protection schemes. Because these elements cannot be coordinated all efforts are made to limit the overlap of zones.

D. It is common for time overcurrent (TOC) protective zones to overlap, however these elements will send a trip command after a variable time delay based on curve timeout, therefore it is possible to make the devices operate in a desired order. The process of developing the required settings to achieve the desired operating order is known as “coordination.” See **Figure 2.5** for an example of TOC coordination.



Time:

Current: 3500

☐ Fine

Device	Curve	Cycles	Current [A]
2-RECLOSER_TCC G&W VIPER	Ground Fast	2.3400	Not Found!
2-RECLOSER_TCC G&W VIPER	Phase Slow	12.3877	Not Found!
1-RELAY SCHWEITZER U1 SEL751	TCC	47.8079	Not Found!

Mode: User Defined

dT: 35.4202 [cy]

Figure 2-5 Sample TCC Graph for TOC Coordination

2.2 Explanation of hot line tag

A. Hot line tag (HLT) is an industry defined function that, when enabled on a device disables reclosing and makes all tripping instantaneous. Any detected fault will cause a trip command to be sent instantaneously and reclosing will not be allowed.

B. HLT is available for crew safety and is used while hot line work is being performed within the MAD.

C. Tripping is made instantaneous to reduce the incident energy released to the smallest amount possible. Reclosing is not allowed so crews have a chance to clear the area if a fault occurs.

2.3 Explanation of reclosing and fuse savings

A. Per IEEE C37.104-2002 85-90% of all faults are transient, meaning a protective device detected a short circuit and interrupted the current flow, and then the fault self-cleared. It is thus desirable to automatically close the protective device without any operator or line crew action. This is known as “reclosing.”

B. The number of recloses is determined by a variety of factors but generally 3 reclose attempts are made. The percentage chance of holding upon reclosing decreases to approximately 15% on the second trip and 1% for all subsequent trips. We can therefore conclude that most faults that don’t clear on the first trip are permanent faults.

C. Given that 85% of faults are transients it is not desirable to operate the fuse when the fault could be cleared and the line automatically restored by an upstream device within a few seconds. This is called a “fuse savings” scheme. To accomplish fuse savings the upstream protective device must operate with a time delay shorter than the fuse total clear time which is typically less than 5 cycles.

D. If fuse savings were eliminated any transient fault downstream from a fuse would result in operation of the fuse. This increases CAIDI because the customers have been interrupted and cannot be remotely restored because the fuse can only be replaced locally, and increased maintenance costs because a line crew must be sent to the location to replace the fuse.

E. On a feeder relay, fuse savings is accomplished with instantaneous elements, however, upon study it was found that fault magnitudes within the typical feeder CB zone of protection will operate the fuse and the CB at the same time. Therefore, fuse savings was eliminated on the feeder CB.

F. In a recloser, fuse savings is accomplished with “fast curves” which operate instantaneously above approximately 1,000A and have a short time delay at lower magnitudes. Old style hydraulic reclosers have 2 fast trips built in to the operating mechanism; modern programmable recloser controls are set to 1 fuse savings operation.

G. In older schemes overlap of fast curves was allowed because of equipment limitations; in modern recloser controls fast trips can be easily blocked, therefore, fuse savings should be limited to one device per fuse. That is, one device should operate one time to save any fuse. Multiple devices may still operate where circuit configuration does not provide for coordination.

3. Feeder Protection

3.1 Description of feeder relay protective elements

A. **Scheme Implementation:** The relay information in this and subsequent sections applies to all *new* protective schemes. While all efforts are made to revise older schemes and bring them up to current standards it is not always possible to replace existing equipment or revisit existing settings in a timely manner.

B. **Current and Potential Inputs:** Protective elements in the primary and backup relays rely mainly on current inputs from the CT, except the Blown Fuse Trip Logic, which uses potential from the PT inputs, and the Under-Frequency trip logic, which uses potential, but can switch to current if the voltage is not available. The CTs are connected on the bus side of the feeder breaker, and the PTs are connected on the 12.47kV bus.

C. **51P1:** 51P1 is a phase time overcurrent element. The pickup is set below the minimum line-end fault, but above maximum load. The time characteristics are adjusted to provide at least 18 cycles of coordination with downstream reclosers. In Group 2, the 51P1 pickup is typically set 1 tap higher than the Group 1 pickup to allow increased load on the feeder.

D. **51P2:** 51P2 is a phase time overcurrent element used for fast tripping when the relay is set to Hot Line Tag. The 51P2 pickup is set the same as the 51P1 pickup, but the time dial is set lower.

E. **51G1:** 51G1 is a residual time overcurrent element. The pickup is set above the allowed feeder unbalance, but below the 51P pickup, in order to detect high-impedance ground faults. A trip on this element will block reclosing, since these faults are frequently caused by downed conductors. The 51G should coordinate with downstream ground elements, if they are in use.

F. **50P1:** 50P1 is a definite time overcurrent element used to provide fast tripping for some portion of the feeder. 50P1 will typically have a definite time delay to allow downstream fuses overreached by the element to operate; however, the delay is set off when the relays are in Group 2 to allow fuse savings.

G. **50P2/Q2:** The 50P2/Q2 elements are used to prevent high side transformer fuses from blowing for a high magnitude feeder fault when the substation is in abnormal configuration, i.e., one of the 12.47kV main or bus section breakers are open at a station where the bus section is normally closed. At a substation with high side circuit breakers/switchers, or at a substation with a normally open bus section breaker, 50P2/Q2 would typically not be used. 50P2 operates on phase current, while 50Q2 operates on negative sequence current.

H. **50P3/Q3:** The 50P3/Q3 elements are used to prevent high side transformer fuses from blowing for a high magnitude feeder fault when the substation is in Normal configuration, and to coordinate with zone distance relays at the remote source substation if the distance settings reach through the transformer into the 12.47kV system. If the transformers have high side circuit breakers/switchers rather than fuses, 50P3/Q3 would be set to cover some portion of the getaway for high magnitude faults, and to coordinate with any overreaching transmission distance elements. 50P3 operates on phase current, while 50Q3 operates on negative sequence current.

I. **Blown Fuse Trip:** Blown Fuse Trip logic is only in use at substations where the high side of the transformer is protected by fuses. If a fault causes only one fuse to operate, phase to neutral 12.47kV bus voltage will be approximately half of nominal on two of the phases. Upon detecting this condition, the logic will wait for three minutes, and then trip the feeder to protect customer equipment from the unbalanced voltage condition. A Blown Fuse trip will also lock out reclosing. If the transformer has a high side circuit breaker/switcher, the Blown Fuse logic should be blocked.

J. **Underfrequency (81) Trip:** If Underfrequency Load Shedding is in use at the substation, and the primary and backup relays are tasked with controlling the scheme, the 81 element will trip the feeder if frequency dips below the set point for more than the specified time delay. The 81 element is supervised by checking for sufficient current and voltage before allowing a trip. The underfrequency scheme at a given substation might or might not be controlled by the primary and backup SEL-751s, as some stations have the scheme implemented by means of a PLC.

3.2 Description of feeder relay inputs

A. **43M Recloser Selector Switch:** If the Recloser Selector switch is set in the Primary position, the primary relay will control reclosing operations. If the switch is set to Backup, the backup relay will control reclosing. This input is used in the relay reclose initiate supervision logic and used to supervise closing.

Relay Trouble (To Backup from Primary only): If the primary relay experiences a trouble state, such as a hardware/software alarm or a complete loss of operation, the backup relay will receive a signal on this input which allows it to assume control of reclosing. The primary relay trouble signal should be connected in parallel with the 43M Recloser Selector Switch so that either primary Relay Trouble OR the 43M switch set in the Backup position will allow the backup relay to assume control of reclosing.

B. **101 NAC Supervisory Disable:** The 101 Circuit Breaker Control Switch must be in the Normal After Close (NAC) position (red semaphore) to allow reclosing, a SCADA close, or a SCADA trip in either relay.

C. **52A Contact:** A 52A contact is required to supervise a number of operations, including Unlatch Trip, Unlatch Close, Reclose Initiate, Unlatch Blown Fuse Alarm, Unlatch Underfrequency Trip Alarm, Manual Closing, Slow Breaker Logic, and Trip and Close Coil Monitors. For example, the relay can use the 52A status to ensure that the breaker has opened before unlatching TRIP.

D. **Activate IOC When Abnormal (Abnormal Station Status):** At a substation with a normally closed bus section breaker (that is, the 12.47kV bus is normally supplied by both transformers in parallel), the primary and backup SEL-751 feeder relays will receive a signal from the SEL-487B bus relays if the station is in an Abnormal condition.

The 487Bs send the Abnormal signal when any of the low side main or bus section breakers are open, indicating that the feeders are only being supplied by a single transformer. The feeder relays are then allowed to trip on 50P2/Q2 settings (see settings discussion below) for a high magnitude fault. At a station with a normally open bus section breaker, this input may be left unwired since the feeders will always be supplied only by a single transformer.

E. **101 CB Control Switch Close:** Turning this switch to the Close position will start a 10 second timer in the primary and backup relays. Upon timeout, both relays will attempt to close the CB.

F. **Input Fuse Monitor:** If DC input voltage is lost to the primary and/or backup relays, circuit breaker trouble logic will send an alarm to SCADA.

G. **Spring Charge Fail:** A low spring charge will typically open the normally closed contacts on 49MX. The primary and backup relay Spring Charge Fail input will thus go low when spring charge is low and circuit breaker trouble logic will send an alarm to SCADA. If no spring charge contact is available, this input should be wired directly to the positive DC supply. The resulting constant high signal will ensure that the Spring Charge Fail logic will not assert.

H. **IPP Reclosing Block:** If there is live voltage from customer-owned generation on a tripped feeder (open contact), a low IPP Block Reclose input will temporarily stall an in-progress reclosing operation. If the voltage persists more than 60 seconds, reclosing will be locked out.

On feeders that do not have significant customer-owned generation, and thus no feeder-side voltage check, this input should be wired directly to the positive DC supply. The resulting constant high signal will ensure that the IPP Block Reclose logic will not assert.

I. **Supervisory (SCADA) Trip:** As long as the 101 Circuit Breaker Control Switch is in the NAC position, a signal received from hardwired SCADA on this input will cause the relay to attempt to open the breaker.

J. **Supervisory (SCADA) Close:** As long as the 101 Circuit Breaker Control Switch is in the NAC position, and the relay is not receiving an IPP Delayed Reclose signal, a signal received from hardwired SCADA on this input will cause the relay to attempt to close the breaker.

K. **Relay Trip Input (Reclose Initiate):** The primary and backup relays each receive a Trip contact from the other relay, i.e., the primary receives a trip from the backup and vice versa. If the primary receives a trip, it will attempt to initiate reclosing, and likewise for the backup.

However, the reclosing initiate will only be successful in the given relay if the previously mentioned reclosing supervision conditions are met.

L. **Close Coil Monitor:** If voltage to the breaker close circuit is lost, the Close Coil Monitor input to the primary and backup relays will go low. If this occurs while the breaker is open, circuit breaker trouble logic will send an alarm to SCADA. Note that there are multiple methods of obtaining the close voltage status, depending on the type of breaker in use.

M. **Trip Coil Monitor:** The Trip Coil Monitor indicates whether the circuit breaker trip coil is continuous/ready to trip while the breaker is closed. If the trip coil is not ready to trip (TCM input is low) and the breaker is closed, relay reclosing will be driven to lockout, and circuit breaker trouble logic will send an alarm to SCADA. Note that there are multiple methods of obtaining the trip coil ready status, depending on the type of breaker in use.

3.3 Description of feeder relay outputs

A. **Trip:** The Trip output from the primary and backup relays is wired to the CB trip coil and will close to trip the breaker for the operation of any relay protective element. Note that the 101 CB Control Switch trip contact is wired directly to the CB trip coil rather than to a relay input and hence will not trip the breaker through the relay.

B. **Close (Manual and Auto):** The Close output from the primary and backup relays is wired to the CB close coil. The output will close the breaker for an operation of the reclose logic, or after a 10-second delay if the 101 CB Control switch is moved to the Close position.

C. **Relay Failure Alarm:** If the primary or backup relay experiences a trouble state, such as a hardware or software alarm, or fails completely, the Relay Failure contact will close. The primary Relay Failure contact is wired to an input on the backup relay, which will allow the backup to assume reclosing control in case of a primary failure. The backup Relay Trouble contact is not used the logic.

D. **SCADA Trip:** As long as the 101 Circuit Breaker Control Switch is in the NAC position, a signal received by the primary and/or backup relay through the Supervisory (SCADA) Trip input, or through a remote open command, will close this output and attempt to open the breaker. The output is wired to the circuit breaker trip coil.

E. **SCADA Close:** As long as the 101 Circuit Breaker Control Switch is in the NAC position, and the relay is not receiving an IPP Delayed Reclose signal, a signal received by the primary and/or backup relay through the Supervisory (SCADA) Close input, or through a remote close command, will close this output and attempt to close the breaker. The output is wired to the circuit breaker close coil.

F. **Breaker Failure Trip:** When the primary or backup relay issues a TRIP command, the relay starts the Breaker Failure Delay (BFD) timer. If BFD times out before the relay detects that all current through the feeder breaker has been interrupted, the relay will issue a Breaker Failure Trip (BFT) to alert the SEL-487B bus relays of the failed breaker. The BFT contact from the primary SEL-751 feeder relay is wired to the SEL-487B/R1 and from the backup feeder relay to the SEL-487B/R2.

G. **Relay Trip Output (Reclose Initiate):** If the primary and/or backup relay trips for any protection function other than 51G, Underfrequency, or Blown Fuse Logic, the Relay Trip (Reclose Initiate) output will indicate to the other relay that the trip has occurred, i.e., the primary signals the backup, and vice versa. This allows both relays to be aware when the other relay has tripped and to initiate reclosing if it is currently tasked with reclosing duty.

4. Substation Transformer Protection

4.1 Explanation of transformer differential scheme protective elements

A. **Scheme Overview:** The SEL-487E transformer relay provides primary differential protection for the transformer, as well as backup protection in the form of overcurrent elements. In addition to current based protection, the relay can also trip the transformer for protective functions (low oil, high temperature, etc.) provided by monitoring equipment in the transformer control cabinet. No reclosing is permitted for any transformer trip, but the 487E will initiate breaker failure to the high side SEL-751 for a trip.

B. **Current Inputs:** The number and location of current inputs to the transformer SEL-487E depends on the type of high side fault interrupter in use.

If the high side device is a circuit switcher, the 487E will typically receive currents from a three-phase CT located on the high side transformer bushings, a three-phase CT on the bus side of the low side main breaker, and a CT on the transformer neutral. The high and low side three-phase CTs are used for transformer differential and overcurrent, and the neutral CT is used for the REF element.

If the high side interrupter is a circuit breaker, the 487E will typically receive currents from a three-phase CT on the line side of the high side breaker, a three-phase CT on the bus side of the low side main breaker, three-phase CTs on the high and low side transformer bushings, and a CT in the transformer neutral.

The breaker CTs are used for transformer differential and overcurrent, the neutral CT is used for the REF element, and the bushing CTs are used for fault location targeting.

The 487E does not receive any potential inputs.

C. **Transformer Differential (87):** The transformer SEL-487E will trip for restrained and unrestrained differential elements (87R and 87U) for faults in the transformer zone of protection. The restrained element functions by comparing operate current with restraint current using the differential characteristic. The unrestrained element functions purely on the operate current and does not consider harmonic blocking or restraint current. This element trips the high and low side fault interrupters.

D. **51P:** 51P is set to protect the transformer against internal faults, as well as faults on the high side of the transformer. The pickup is set above load, while the curve is chosen to coordinate with the transformer damage curve and the transformer inrush current, and the time dial is chosen to coordinate with the transformer damage curve, the transformer inrush current, and the low side feeder curves. 51P is set the same as a similar element in the high side SEL-751. This element trips the high and low side fault interrupters.

E. **51G:** 51G is set to protect the transformer against internal ground faults, as well as ground faults on the high side of the transformer. Since the element is not responsive to load, it can be set more sensitively than the corresponding phase element (51P), but must coordinate with the remote transmission terminal ground relays. The pickup is selected to be above the highest transformer unbalance due to load, while the curve and time dial are selected to coordinate with the transmission relays. 51G is set the same as a similar element in the high side SEL-751. This element trips the high and low side fault interrupters.

F. **50P:** 50P is set to protect the high side of the transformer and might protect for some internal faults. It is set above the transformer's rated current and above the low side's maximum fault current, and hence does not require a time delay to coordinate with low side devices. This element trips the high and low side fault interrupters.

G. **50G:** 50G is set to protect the high side of the transformer for ground faults and might protect for some internal faults. It should be set slightly lower than the 50G element at the remote transmission terminal, which assumes that both the local and remote breakers will trip. However, the local breaker will not reclose, while the remote breaker will. 50G is set the same as a similar element in the high side SEL-751. This element trips the high and low side fault interrupters.

H. **REF:** The Restricted Earth Fault (REF) element provides sensitive detection of ground faults which occur near the transformer neutral. REF compares current in the transformer neutral with 3I0 on the low side of the transformer to determine if a fault exists. The REF element will be disabled if no transformer neutral CT is available. This element trips the high and low side fault interrupters.

I. **Transformer Low Oil Level Trip:** The relay will trip the high and low side fault interrupters if transformer monitoring equipment indicates that transformer main tank oil level is low (below a specific level). If oil level monitoring is not available or tripping is not desired, the logic can be disabled.

J. **Transformer Winding Temperature Trip:** The relay will trip the high and low side fault interrupters if transformer monitoring equipment indicates that the transformer winding temperature is excessive. If winding temperature monitoring is not available or tripping is not desired, the logic can be disabled.

K. **Transformer Fault Pressure Trip:** The relay will trip the high and low side fault interrupters if transformer monitoring equipment indicates that sudden/fault pressure is excessive. If the relay detects a fault outside of the differential zone, sudden/fault pressure tripping will be blocked. If pressure monitoring is not available or tripping is not desired, the logic can be disabled.

L. **LTC Oil Temp Trip:** The relay will trip the high and low side fault interrupters if transformer monitoring equipment indicates that LTC oil temperature is excessive. If LTC oil temperature monitoring is not available or tripping is not desired, the logic can be disabled.

M. **LTC Low Oil Trip:** The relay will trip the high and low side fault interrupters if transformer monitoring equipment indicates that LTC oil level is low (below a specific level). If LTC oil level monitoring is not available or tripping is not desired, the logic can be disabled.

4.2 SEL-487E relay inputs explanation

A. **High Side Fault Interrupter 52A:** A high side fault interrupter 52A contact is included in the relay Event Reports (ER), Sequential Events Recorder (SER) and breaker monitoring, but is not used to supervise any protection or control operations.

B. **Low Side Main 52A:** A low side main circuit breaker 52A contact is included in the relay Event Reports (ER) and Sequential Events Recorder (SER), but is not used to supervise any protection or control operations.

C. **Transformer Low Oil Level Trip (Normally Open):** The relay will receive a signal on this input if monitoring equipment indicates that the transformer main tank oil level is low (below a specific level). The contact used to supply this signal is normally open, and must logically agree with a normally closed oil level monitoring contact (below) before the relay will issue a transformer trip. If this monitor is not available or tripping is not desired, the logic can be disabled.

D. **Transformer Low Oil Level Trip (Normally Closed):** The relay will see the signal on this input drop out if monitoring equipment indicates that the transformer main tank oil level is low (below a specific level). The contact used to supply this signal is normally closed, and must logically agree with a normally open oil level monitoring contact (above) before the 487E will issue a transformer trip. If this monitor is not available or tripping is not desired, the logic can be disabled.

E. **Transformer Winding Temperature Trip:** The relay will receive a signal on this input and issue a transformer trip if monitoring equipment indicates that the transformer winding temperature is excessive. If this monitor is not available or tripping is not desired, the logic can be disabled.

F. **Transformer Fault Pressure Trip:** The relay will receive a signal on this input if monitoring equipment indicates that transformer sudden pressure (fault pressure) is excessive. The 487E supervises this input with relay word bit CON (external fault detected). If CON is low (that is, no external fault is detected) and the sudden pressure input is high, the relay will issue a transformer trip. If this monitor is not available or tripping is not desired, the logic can be disabled.

G. **LTC Oil Temp Trip:** The transformer SEL-487E will receive a signal on this input and issue a transformer trip if monitoring equipment indicates that the LTC oil temperature is excessive. If this monitor is not available or tripping is not desired, the logic can be disabled.

H. **LTC Low Oil Level Trip (Normally Open):** The relay will receive a signal on this input if monitoring equipment indicates that the LTC oil level is low. The contact used to supply this signal is normally open, and must logically agree with a normally closed oil level monitoring contact (below) before the 487E will issue a transformer trip. If this monitor is not available or tripping is not desired, the logic can be disabled.

I. **LTC Low Oil Level Trip (Normally Closed):** The relay will see the signal on this input drop out if monitoring equipment indicates that the LTC oil level is low. The contact used to supply this signal is normally closed, and must logically agree with a normally open oil level monitoring contact (above) before the 487E will issue a transformer trip. If this monitor is not available or tripping is not desired, the logic can be disabled.

J. **Input Fuse Monitor:** If DC input voltage is lost to the relay, trouble logic will send an alarm to SCADA.

K. **Winding Temperature Fuse Monitor:** If DC input voltage to the equipment associated with Transformer Winding Temperature monitoring is lost, this input will drop out and relay logic will send an alarm to SCADA.

L. **Top Oil Temperature Fuse Monitor:** If DC input voltage to the equipment associated with Top Oil Temperature monitoring is lost, this input will drop out and relay logic will send an alarm to SCADA.

M. **Fault Pressure Trip Fuse Monitor:** If DC input voltage to the equipment associated with Fault Pressure monitoring is lost, this input will drop out and relay logic will send an alarm to SCADA.

4.3 SEL-487E relay outputs explanation

A. **Trip High Side Fault Interrupter Trip Coil 1:** The relay will trip the high side fault interrupter through this output for the following elements/conditions: Transformer differential (restrained or unrestrained), overcurrent (inverse or instantaneous), Restricted Earth Fault (REF), Transformer Low Oil, Transformer Winding Temperature, Transformer Fault Pressure, LTC Oil Temperature, or LTC Low Oil. This output is wired to the high side fault interrupter trip coil.

B. **Trip High Side Fault Interrupter Trip Coil 2:** The relay will trip the high side fault interrupter through this output for the following elements/conditions: Transformer differential (restrained or unrestrained), overcurrent (inverse or instantaneous), Restricted Earth Fault (REF), Transformer Low Oil, Transformer Winding Temperature, Transformer Fault Pressure, LTC Oil Temperature, or LTC Low Oil. This output is wired to the high side fault interrupter trip coil #2. It is left unwired if the fault interrupter does not have a second trip coil.

C. **Breaker Failure Initiate to High Side SEL-751:** Upon issuing a transformer trip command, the transformer SEL-487E will signal the high side SEL-751 to initiate breaker failure on the fault interrupter.

D. **Trip Low Side CB:** The relay will trip the low side main breaker through this output for the following elements/conditions: Transformer differential (restrained or unrestrained), overcurrent (inverse or instantaneous), Restricted Earth Fault (REF), Transformer Low Oil, Transformer Winding Temperature, Transformer Fault Pressure, LTC Oil Temperature, or LTC Low Oil. This output is wired to the low side main breaker trip coil.

E. **Trip Low Side CB Status (No reclose):** If the transformer SEL-487E issues a transformer trip, this contact will close to signal the low side main SEL-751 that the trip has occurred and to block reclosing. Upon receiving the signal, the 751 will retrip the breaker and drive reclosing to lockout.

F. **Relay Testing 87 Trip:** The Relay Testing Differential Trip output will close for a restrained or unrestrained (87R or 87U) transformer differential trip.

G. **Relay Testing 50/51 Trip:** The Relay Testing 50/51 Trip output will close for any overcurrent trip (REF, 51P, 51G, 50P, 50G).

4.4 SEL-751 TX protective element explanation

A. **Current and Potential Inputs:** Protective elements in the high side SEL-751 rely mainly on current inputs from the CTs, except for the 59P Balanced Power trip signal to the SEL-487B bus relays, which uses potential from the PT inputs, and the Low Gas Lockout which depends on a contact signal from the fault interrupter.

The three-phase CTs are connected on the high side of the transformer, and might be shared with the SEL-487E transformer differential, depending on whether the high side fault interrupter is a circuit switcher or a circuit breaker. If the high voltage lightning arrester lies outside of the transformer differential zone of protection, currents from a CT connected to the ground lead of the arrestor will also be provided to the 751.

The PTs are connected A-phase-to-ground and C-phase-to-ground on the high side of the transformer. No B-phase PT is connected because in the event of a high side ground fault, the voltage on two of the phases will rise. Thus, for any ground fault, at least A or C will provide indication to the relay.

B. **50P2:** 50P2 is set to protect the high side of the transformer and might protect for some internal faults. It is set above the transformer’s rated current and above the low side’s maximum fault current, and hence does not require a time delay to coordinate with low side devices. 50P2 is backup to a similar element in the SEL-487E transformer relay.

C. **50P3:** 50P3 is a “high set” instantaneous phase overcurrent element. Its function is to serve as last-chance phase protection in case of failure in other phase elements. 50P3 is not settable in the RDB template.

D. **51P:** 51P is set to protect the transformer against internal faults, as well as faults on the high side of the transformer. The pickup is set above load, while the curve is chosen to coordinate with the transformer damage curve and the transformer inrush current, and the time dial is chosen to coordinate with the transformer damage curve, the transformer inrush current, and the low side feeder curves. 51P is backup to a similar element in the SEL-487E transformer relay.

E. **50N1:** The 50N1 element is only in use at stations that have a circuit switcher as the high side fault interrupter. The element receives current from a CT in the ground lead of the lightning arrester and is used to detect a failed arrester.

F. **50N2:** 50N2 is a “high set” instantaneous element. Its function is to serve as last-chance failed lightning arrester protection in case of failure in the 50N1 element. 50N2 is not settable in the RDB template.

G. **51G:** 51G is set to protect the transformer against internal ground faults, as well as ground faults on the high side of the transformer. Since the element is not responsive to load, it can be set more sensitively than the corresponding phase element (51P), but must coordinate with the remote transmission terminal ground relays. The pickup is selected to be above the highest transformer unbalance due to load, while the curve and time dial are selected to coordinate with the transmission relays. 51G is backup to a similar element in the SEL-487E transformer relay.

H. **50G1:** 50G1 is set to protect the high side of the transformer for ground faults and might protect for some internal faults. It should be set slightly lower than the 50G element at the remote transmission terminal, which assumes that both the local and remote breakers will trip. However, the local breaker will not reclose, while the remote breaker will. 50G1 is backup to a similar element in the SEL-487E transformer relay.

I. **50G2:** 50G2 is a “high set” instantaneous phase overcurrent element. Its function is to serve as last-chance ground protection in case of failure in other ground elements. 50G2 is not settable in the RDB template.

J. **59P:** 59P is an overvoltage element used to protect B-type substations from single-phase-to-ground faults on the 69kV system. The delta high side of the 69/12.47kV transformer cannot provide zero sequence current for a ground fault, thus the voltage will rise on the two unfaulted high side phases. Once the remote terminal trips for the fault, the high side SEL-751 will signal the SEL-487B bus relays to trip the low side main breaker and isolate the fault.

K. **Low Gas Lockout:** If the high side fault interrupter provides a low gas lockout contact to the SEL-751 high side relay, the relay will include the lockout in the trip equation, as well as the breaker failure initiate equation.

L. **Breaker Failure Initiate:** The relay includes the following elements/inputs in the breaker failure initiate equation: Any trip, except a trip due to a failure of the low side main circuit breaker; a breaker failure initiate signal from the SEL-487E transformer relay; or a low gas fault interrupter lockout. Upon initiation of the breaker failure timer, the relay will retrip the fault interrupter. If breaker failure times out, the relay will send a signal to trip the low side main breaker and attempt to open the high side MOD or the circuit switch disconnects, depending on the equipment in use.

M. **Low Side Main Circuit Breaker Failure:** If the high side SEL-751 receives a signal from the SEL-487B bus relay that the low side main circuit breaker has failed, the 751 will trip the high side fault interrupter.

4.5 SEL-751 TX relay inputs explanation

A. **Fault Interrupter 52A Contact:** A 52A contact is required to supervise a number of operations, including Unlatch Trip, Unlatch Close, Trip Coil and Close Coil Monitors, Slow Trip and Slow Close alarms, and Open and Close MOD outputs. For example, the relay uses the 52A status in conjunction with current detection to ensure that the high side fault interrupter has opened before unlatching TRIP.

B. **Circuit Fault interrupter 52B Contact:** A 52B contact is used by the relay to supervise the 10 second delay for local control switch open or close of the high side MOD.

C. **Trip Coil Monitor #1:** The Trip Coil Monitor indicates whether the high side fault interrupter trip coil #1 is continuous/ready to trip while the fault interrupter is closed. If the trip coil is not ready to trip (TCM input is low) and the fault interrupter is closed, circuit breaker trouble logic in the relay will send an alarm to SCADA.

D. **Close Voltage Monitor:** If voltage to the high side fault interrupter close circuit is lost, the Close Voltage Monitor input to the relay will go low. If this occurs while the fault interrupter is open, circuit breaker trouble logic will send an alarm to SCADA.

E. **Trip Coil Monitor #2:** The Trip Coil Monitor indicates whether the high side fault interrupter trip coil #2 is continuous/ready to trip while the switcher is closed. If the trip coil is not ready to trip (TCM input is low) and the fault interrupter is closed, circuit breaker trouble logic in the relay will send an alarm to SCADA.

F. **Low Side Circuit Breaker Fail:** If the SEL-487B bus relays receive a signal indicating that the low side main breaker has failed, the 487Bs will pass that signal to the high side SEL-751. The 751 will then trip the high side circuit fault interrupter and will not initiate breaker failure.

G. **Input Fuse Alarm:** If DC input voltage is lost to the relay, circuit breaker trouble logic will send an alarm to SCADA.

H. **MOD Contact:** An ‘a’ contact from the high side MOD is used to indicate MOD open/close status to SCADA. This contact is only available if a separate MOD is in use.

I. **Breaker Failure Initiate from SEL-487E:** The SEL-487E transformer relay will send a signal to the high side SEL-751 for any transformer trip. Upon receiving this input, the 751 will initiate breaker failure timing for the high side fault interrupter.

J. **Low Gas Pressure Alarm:** If gas pressure in the high side circuit breaker drops below the specified alarm level, this relay input will go high and send an alarm to SCADA.

K. **Low Gas Pressure Lockout Alarm:** If gas pressure in the high side circuit breaker drops below the specified lockout level, this relay input will go high and send an alarm to SCADA. A gas lockout will also cause the relay to trip the circuit breaker and initiate breaker failure.

L. **Spring Charge Fail:** A low spring charge will typically open the normally closed contacts on 49MX. The relay Spring Charge Fail input will thus go low when spring charge is low and circuit breaker trouble logic will send an alarm to SCADA.

M. **CB Control Switch Close:** Turning this control switch to the Close position will start a 10 second timer in the relay. Upon timeout, the relay will attempt to close the high side fault interrupter, as long as it is open.

N. **101 Supervisory Disable:** The 101 Circuit Breaker Control Switch must be in the Normal After Close (NAC) position for the relay to allow a SCADA close of the circuit fault interrupter.

O. **MOD Control Switch NAC:** The MOD Control Switch must be in the Normal After Close (NAC) position for the relay to allow a local or remote close of the MOD. The control switch is only installed/wired if a separate MOD is in use.

P. **MOD Control Switch Open:** If the high side circuit breaker is open, turning the MOD control switch to the trip position will start a 10 second timer in the relay. Upon timeout, the relay will attempt to open the high side MOD. The control switch is only installed/wired if a separate MOD is in use.

Q. **MOD Control Switch Close:** If the high side circuit breaker is open, turning the MOD control switch to the close position will start a 10 second timer in the relay. Upon timeout, the relay will attempt to close the MOD, as long as the breaker is still open and the MOD control switch is in the NAC position. The control switch is only installed/wired if a separate MOD is in use.

4.6 SEL-751 TX relay outputs explanation

A. **Breaker Failure Trip to Low Side Breaker:** The high side SEL-751 will initiate breaker failure timing on the high side circuit fault interrupter for the following conditions: Any trip, other than a low side breaker fail trip; a breaker failure initiate signal from the SEL-487E transformer relay; or a low gas lockout from the high side breaker. If breaker failure times out, the 751 will issue a trip with no reclose signal through this contact to the low side SEL-751.

B. **Close (Manual and Auto):** If the 101 CB Control Switch is turned to the close position, the relay will start a 10 second timer. Upon time out, the relay will attempt to close the high side fault interrupter after ensuring that it is already open.

C. **SCADA Open:** A signal received by the relay through a SCADA remote open command will close this output and attempt to open the circuit fault interrupter. The output is wired to the trip coil.

D. **SCADA Close:** As long as the 101 CB Control Switch is in the NAC position, a signal received by the relay through a SCADA remote close command will close this output and attempt to close the high side fault interrupter after ensuring that it is already open. The output is wired to the close coil.

E. **Balanced Power Trip to 487B/R1:** If the high side SEL-751 detects an overvoltage condition on the high side of the transformer, this contact will close to send a signal to bus relay SEL-487B/R1, which will in turn trip the low side main breaker.

F. **Balanced Power Trip to 487B/R2:** If the high side SEL-751 detects an overvoltage condition on the high side of the transformer, this contact will close to send a signal to bus relay SEL-487B/R2, which will in turn trip the low side main breaker.

G. **Open MOD:** The high side SEL-751 will close this contact to open the high side MOD or the circuit switcher disconnects for three conditions. The first condition is if breaker failure times out in the relay. After a breaker failure trip, the relay will wait 2 additional seconds, then open the MOD/disconnects even if the breaker/switcher is closed.

   The second condition is after receiving an open signal from the MOD control switch. The relay will wait for 10 seconds, then open the MOD after ensuring that the circuit breaker/switcher is already open. This function is only available if a separate MOD is in use.

   The third condition is upon receiving a remote MOD open command from SCADA.

H. **Close MOD:** This output will attempt to close the high side MOD after a 10 second delay if the MOD control switch is turned to the close position, or if the relay receives a remote MOD close command from SCADA. In both cases, the circuit breaker/switcher must be open and the MOD control switch must be in the NAC position to attempt the close operation. The MOD control switch is only installed/wired if a separate MOD is in use.

I. **Trip Breaker Trip Coil #1:** This output is wired to the high side fault interrupter trip coil #1 and will close to trip the fault interrupter for any protective trip, any breaker failure initiation, or for a breaker failure on the low side breaker.

J. **Trip Breaker Trip Coil #2:** This output is wired to the high side fault interrupter trip coil #2 and will close to trip the fault interrupter for any protective trip, any breaker failure initiation, or for a breaker failure on the low side breaker. Note that a circuit switcher will typically only have a single trip coil.

5. Substation Bus Protection

5.1 Explanation of bus differential scheme protective elements

A. **Scheme Overview:** The SEL-487B bus relays provide differential protection for the bus, as well as balanced power protection for the transformers. Differential trips are issued based on the zone (bus L or bus R) in which the fault occurs. Balanced power trips are issued by the 487Bs either for reverse power through the transformer, or upon receiving an overvoltage signal from the high side SEL-751.

   Although there are two 487Bs (R1 and R2), neither relay is consider primary or backup, with both relays being able to provide all protection and control capabilities.

In addition to strictly protective functions, the 487Bs also signal the appropriate SEL-751 breaker relays to allow or block reclosing, trip adjacent breakers for failed breaker conditions, and perform auto transfers for loss of voltage on the low side buses.

B. **Current and Potential Inputs:** Protective elements in the bus SEL-487Bs rely on current from CTs (bus differential, reverse power), and potential from PTs (trip/auto transfer for loss of voltage), as well as contact logic from other relays (breaker failure, high side over voltage).

The SEL-487Bs receive currents from three-phase CTs on the feeder side of all feeder breakers, both sides of the bus section breaker, and the transformer side of both low side main breakers. All CTs are connected so that current flowing into the bus is seen as positive current by the relay.

The 487Bs also receive A-phase-to-ground potential from the L side of the bus section breaker, and C-phase-to-ground potential from the R side of the bus section breaker.

C. **Bus Differential (87):** The SEL-487Bs will trip on restrained and unrestrained differential elements for faults in either bus zone of protection. The differential elements in the relays are divided into three separate zones: A zone for bus R, a zone for bus L, and an overall “Check Zone” which combines both buses into a single zone. In order to issue a differential trip for a specific bus, the relays must sense a fault internal to the zone for that bus, as well as internal to the Check Zone.

D. **Trip for Loss of Voltage:** At a station with a normally open bus section breaker, the SEL-487Bs will trip the appropriate low side main breaker if voltage is lost on either bus due to loss of the transmission line. If all other conditions are met, the relay will attempt to energize the dead bus from the live bus by issuing a close to the bus section breaker.

E. **Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from an adjacent SEL-751 relay, the 487Bs will trip the correct surrounding breakers and signal the associated SEL-751s to block reclosing.

F. **Balanced Power (Reverse Power):** Reverse power protection consists of six 51P phase inverse time overcurrent elements, one for each phase on both of the low side main breakers. These elements are torque controlled by directional elements in the low side main SEL-751s. If the 51P elements time out for an overcurrent and the torque control from the 751s indicate reverse current (current flowing from the low side bus towards the high side bus through a transformer), the 487Bs will trip the appropriate low side main breaker.

The 487Bs will only trip for reverse power if both of the low side main breakers and the bus section breaker are closed.

G. **Balanced Power (Overvoltage) from High Side Relay:** At a B-type substation, a high side SEL-751 that senses an overvoltage (59) will signal the SEL-487s to trip the appropriate low side main breaker. For more information on the 59 element, see the Protective Elements section of the high side SEL-751 Operating Philosophy document.

5.2 SEL-487B relay inputs explanation

A. **Bus Section 52A Contact:** A bus section breaker 52A contact is used to supervise a number of operations in the SEL-487Bs, including supervision of Balanced Power tripping, Balanced Power closing, initial conditions for Loss of Voltage Auto Transfers, and bus section breaker tripping for bus restoration after an auto transfer. At a B-type substation, the bus section 52A is used as part of the logic that signals the feeder SEL-751s when the station is in normal or abnormal configuration.

B. **Bus Section Breaker Failure:** If the SEL-487Bs receive a bus section breaker failure signal from the bus section SEL-751, the 487Bs will trip both low side main breakers, block reclosing, and block auto transfers.

C. **Main R 52A Contact:** A 52A contact from main breaker R is used to supervise a number of operations in the SEL-487Bs, including supervision of Balanced Power tripping, Balanced Power closing, initial conditions for Loss of Voltage Auto Transfers, bus section breaker closing for auto transfers, and bus section breaker tripping for bus restoration after an auto transfer. At a B-type substation, the main R 52A is used as part of the logic that signals the feeder SEL-751s when the station is in normal or abnormal configuration.

D. **Main R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the main R SEL-751, the 487Bs will retrip main R and block reclosing, trip the bus section breaker (assuming it is closed) and block reclosing, block auto transfers, and trip the transformer high side fault interrupter and block reclosing.

E. **Balanced Power Reverse Direction Main R:** When the main R SEL-751 detects current flowing from the low side bus towards the high side (reverse direction), the 751 will signal the bus SEL-487Bs. The 487Bs use this input to torque control Balanced Power tripping elements (see Balanced Power in the Protective Elements section, below).

F. **2R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 2R SEL-751, the 487Bs will trip the main R breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

G. **3R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 3R SEL-751, the 487Bs will trip the main R breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is already open), and block auto transfers.

H. **4R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 4R SEL-751, the 487Bs will trip the main R breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

I. **5R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 5R SEL-751, the 487Bs will trip the main R breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

J. **6R Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 6R SEL-751, the 487Bs will trip the main R breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

K. **Balanced Power (59) TXR:** The TXR high side SEL-751 will send a signal to the bus SEL-487Bs if an overvoltage condition is detected on the high side of the transformer. Upon receiving the signal on this input, the 487Bs will trip the main R breaker, block reclosing, and disable auto transfers.

L. **Input Fuse Monitor:** If DC input voltage is lost to the bus SEL-487Bs, relay logic will send an alarm to SCADA.

M. **Main L 52A Contact:** A 52A contact from main breaker L is used to supervise a number of operations in the SEL-487Bs, including supervision of Balanced Power tripping, Balanced Power closing, initial conditions for Loss of Voltage Auto Transfers, bus section breaker closing for auto transfers, and bus section breaker tripping for bus restoration after an auto transfer. At a B-type substation, the main L 52A is used as part of the logic that signals the feeder SEL-751s when the station is in normal or abnormal configuration.

N. **Main L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the main L SEL-751, the 487Bs will retrip main L and block reclosing, trip the bus section breaker (assuming it is closed) and block reclosing, block auto transfers, and trip the transformer high side fault interrupter and block reclosing.

O. **Balanced Power Reverse Direction Main L:** When the main L SEL-751 detects current flowing from the low side bus towards the high side (reverse direction), the 751 will signal the bus SEL-487Bs. The 487Bs use this input to torque control Balanced Power tripping elements (see Balanced Power in the Protective Elements section, below).

P. **2L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 2L SEL-751, the 487Bs will trip the main L breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

Q. **3L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 3L SEL-751, the 487Bs will trip the main L breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

R. **4L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 4L SEL-751, the 487Bs will trip the main L breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

S. **5L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 5L SEL-751, the 487Bs will trip the main L breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

T. **6L Breaker Failure:** If the SEL-487Bs receive a breaker failure signal from the feeder 6L SEL-751, the 487Bs will trip the main L breaker and block reclosing, trip the bus section breaker and block reclosing (assuming it is closed), and block auto transfers.

U. **Balanced Power (59) TXL:** The TXL high side SEL-751 will send a signal to the bus SEL-487Bs if an overvoltage condition is detected on the high side of the transformer. Upon receiving the signal on this input, the 487Bs will trip the main L breaker, block reclosing, and disable auto transfers.

5.3 SEL-487B relay outputs explanation

A. **Main R Trip:** The bus SEL-487Bs will trip the main R breaker through this output for the following conditions: A bus R differential trip, a main R breaker failure, a bus R feeder breaker failure, a bus section breaker failure, an R-side reverse power or overvoltage (balanced power) trip, or loss of voltage on bus R (auto transfer). This output is wired to the breaker trip coil.

B. **Main L Trip:** The bus SEL-487Bs will trip the main L breaker through this output for the following conditions: A bus L differential trip, a main L breaker failure, a bus L feeder breaker failure, a bus section breaker failure, an L-side reverse power or overvoltage (balanced power) trip, or loss of voltage on bus L (auto transfer). This output is wired to the breaker trip coil.

C. **Bus Section Trip:** The bus SEL-487Bs will trip the bus section breaker for the following conditions (assuming it is closed): A differential trip on either bus R or bus L, a feeder breaker failure on either bus, a main R or main L breaker failure, or to re-open the bus section breaker for successful restoration of a bus after a loss of voltage auto transfer. This output is wired to the breaker trip coil.

D. **Bus Section Close, Auto Transfer:** After the bus SEL-487Bs trip the appropriate low side main breaker for a loss of bus voltage, the 487Bs will issue a close signal through this output to the bus section SEL-751. The 751 will then attempt to close the bus section breaker after checking for certain conditions. If the bus section breaker successfully closes, the dead bus will be energized by the live bus.

E. **Station in Abnormal State, 'Type B':** The SEL-751 feeder relays at a B-type substation have two levels of instantaneous overcurrent protection. The correct instantaneous element to be used is dependent on whether the station is in normal or abnormal configuration. If either of the low side main breakers or the bus section breaker is open, the SEL-487Bs will send a signal through this output to an auxiliary relay, which in turn signals the feeder 751s indicating that the station is in abnormal configuration.

F. **Relay Testing Differential (87) Trip:** The Relay Testing Differential Trip output will close for a bus differential trip on either the R bus or the L bus.

G. **Relay Testing Breaker Failure Trip:** The Relay Testing Breaker Failure Trip output will close for a feeder breaker failure trip on either the R bus or L bus, or on the main R or main L breaker.

H. **Bus Section Trip Status, Reclose:** If the bus SEL-487Bs trip the bus section breaker for a differential fault on either bus, the 487Bs will close this contact to signal the bus section SEL-751 that reclosing is permitted. This contact will only close if the number of permitted bus differential operations has not been exceeded.

I. **Bus Section Trip Status, No Reclose:** If the bus SEL-487Bs trip the bus section breaker for a feeder breaker failure on either the R bus or L bus, a breaker failure on the main R or main L breaker, or a successful bus restoration after an auto transfer, the 487Bs will close this contact to signal the bus section SEL-751 that reclosing is not permitted.

J. **Main R Close Status, Balanced Power:** After tripping main R for balanced power (reverse power or high side overvoltage), the SEL-487Bs will wait for a selectable time, then close this contact and send a signal to the main R SEL-751 requesting a breaker close. Before sending the signal, the 487Bs will check that the allowable number of balanced power operations has not been exceeded and that the bus section breaker is closed.

K. **Main R Trip Status, No Reclose:** Upon tripping the main R breaker for any of the following reasons, the bus SEL-487Bs will close this contact to send a signal to the main R SEL-751 that reclosing is not permitted: Bus section breaker failure, a balanced power operation (reverse power or high side overvoltage), bus R feeder breaker failure, main R breaker failure, or the number of allowable bus differential operations is exceeded.

L. **Main R Trip Status, Reclose:** If the SEL-487B trips main R for a differential fault on bus R, or as part of a loss of voltage auto transfer, this contact will close to send a signal to the main R SEL-751 that reclosing is permitted. This contact will only close for a differential trip if the number of permitted bus differential operations has not been exceeded.

M. **TXR Circuit Breaker Trip:** If the bus SEL-487Bs receive a breaker failure trip signal from the main R SEL-751, the 487Bs will trip the TXR high side fault interrupter. This output is wired to the fault interrupter trip coil.

N. **TXR Circuit Breaker Trip, No Reclose (Main R Failed):** If the bus SEL-487Bs receive a breaker failure trip signal from the main R SEL-751, the 487Bs will close this contact to signal the TXR high side SEL-751 to block breaker failure initiate and retrip the breaker.

O. **TXL Circuit Breaker Trip:** If the bus SEL-487Bs receive a breaker failure trip signal from the main L SEL-751, the 487Bs will trip the TXL high side fault interrupter. This output is wired to the fault interrupter trip coil.

P. **TXL Circuit Breaker Trip, No Reclose (Main L Failed):** If the bus SEL-487Bs receive a breaker failure trip signal from the main L SEL-751, the 487Bs will close this contact to signal the TXL high side SEL-751 to block breaker failure initiate and retrip the breaker.

Q. **Main L Close Status, Auto Transfer:** After tripping main L for balanced power (reverse power or high side overvoltage), the SEL-487Bs will wait for a selectable time, then close this contact and send a signal to the main L SEL-751 requesting a breaker close. Before sending the signal, the 487Bs will check that the allowable number of balanced power operations has not been exceeded and that the bus section breaker is closed.

R. **Main L Trip Status, No Reclose:** Upon tripping the main L breaker for any of the following reasons, the bus SEL-487Bs will close this contact to send a signal to the main L SEL-751 that reclosing is not permitted: Bus section breaker failure, a balanced power operation (reverse power or high side overvoltage), bus L feeder breaker failure, main L breaker failure, or the number of allowable bus differential operations is exceeded.

S. **Main L Trip Status, Reclose:** If the SEL-487B trips main L for a differential fault on bus L, or as part of a loss of voltage auto transfer, this contact will close to send a signal to the main L SEL-751 that reclosing is permitted. This contact will only close for a differential trip if the number of permitted bus differential operations has not been exceeded.

5.4 SEL-751 main relay protective elements explanation

A. **Scheme Overview:** The low side main SEL-751 performs control and monitoring functions for the 12.47 kV low side main circuit breaker.

Protective trips are issued directly to the breaker by the SEL-487B bus and SEL-487E transformer relays, and also communicated to the low side SEL-751. The 751 will retrip the breaker upon receipt of the trip signal, and controls reclosing, only allowing the reclose process to begin if the trip was caused by a bus fault or an auto transfer due to loss of voltage. The 751 will also begin timing and notify the SEL-487Bs if breaker failure times out.

If the trip was due to failure of an adjacent breaker, an excessive number of bus differential operations, a transformer trip, or a balanced power trip, reclosing will be locked out. Breaker failure will not be initiated in the low side SEL-751 for a trip that does not allow reclosing.

The relay also handles local control switch closing, SCADA trip, SCADA close, and breaker monitoring functions such as trip coil, close coil, and spring charge alarms.

B. **Current and Potential Inputs:** The low side SEL-751 is primarily a control relay, but does perform two protective functions. The relay can send a breaker failure trip signal to the SEL-487Bs as necessary, and also supplies directional torque control signaling to the 487Bs for balanced power trips. Both functions rely on current inputs from CTs connected on the transformer side of the low side main breaker.

The relay also receives voltages from PTs connected on both sides of the low side main breaker. Voltages from the bus side are three phase to neutral, while the voltage coming from the transformer side is C phase to neutral only. These voltages are used to qualify breaker closing conditions. (See Input: Close from SEL-487B, above, for more information on voltage checks).

5.5 SEL-751 main relay inputs explanation

A. **52A Contact:** A 52A contact is required to supervise a number of operations, including Unlatch Trip, Unlatch Close, Reclose Initiate, Auto Transfer Logic, Slow Breaker Logic, and Trip and Close Coil Monitors. For example, the relay uses the 52A status to ensure that the breaker has opened before unlatching TRIP.

B. **Spring Charge Fail:** A low spring charge will typically open the normally closed contacts on 49MX. The relay Spring Charge Fail input will thus go low when spring charge is low and circuit breaker trouble logic will send an alarm to SCADA.

C. **Close from SEL-487B:** If the SEL-487B bus relays issue an auto transfer close to the low side main SEL-751, the low side relay will check several conditions before attempting to close the breaker. To close, the line side of the breaker must be Live (>95% nominal voltage) and the bus side must be Dead (<25% nominal voltage), or the two sides must pass a synch check. Additionally, the 101 Circuit Breaker Control Switch must be in the Normal After Close (NAC) position to prevent closing the breaker if it has been locally tripped through the 101 switch.

D. **Trip Status, No Reclose:** The SEL-487B bus, SEL-487E transformer, and the high side SEL-751 relays will send a signal to the low side SEL-751 if they are issuing a trip for the following reasons: A breaker failure condition, a balanced power trip, the bus differential has exceeded its maximum number of operations, or a transformer trip. Upon receiving this signal the low side SEL-751 will retrip the breaker and drive reclosing to lockout. These trips will not initiate breaker failure.

E. **Trip Status, Reclose:** The SEL-487B bus relay will send a signal to the low side SEL-751 if it is issuing a trip for the following reasons: A bus differential operation, or an auto transfer due to loss of voltage. Upon receiving this signal the low side SEL-751 will retrip the breaker and initiate breaker failure timing. Reclosing will not be blocked by this input, thus reclosing operations can begin normally if all other supervision conditions permit.

F. **Close Coil Monitor:** If voltage to the low side breaker close circuit is lost, the Close Coil Monitor input to the relay will go low. If this occurs while the breaker is open, circuit breaker trouble logic will send an alarm to SCADA. Note that there are multiple methods of obtaining the close voltage status, depending on the type of breaker in use.

G. **101 CB Control Switch Close:** Turning this switch to the Close position will start a 10 second timer in the relay. Upon timeout, the relay will attempt to close the breaker as long as the voltage check is passed (see Input: Close from SEL-487B, above), and the 101 switch is back in the NAC position.

H. **Input Fuse Alarm:** If DC input voltage is lost to the relay, circuit breaker trouble logic will send an alarm to SCADA.

I. **Trip Coil Monitor:** The Trip Coil Monitor indicates whether the circuit breaker trip coil is continuous/ready to trip while the breaker is closed. If the trip coil is not ready to trip (TCM input is low) and the breaker is closed, circuit breaker trouble logic in the relay will send an alarm to SCADA. Note that there are multiple methods of obtaining the trip coil ready status, depending on the type of breaker in use.

J. **101 NAC Supervisory Disable:** The 101 Circuit Breaker Control Switch must be in the Normal After Close (NAC) position for the low side SEL-751 to allow reclosing, a SCADA close, a local control switch close, or a close from the SEL-487B bus differential relays.

5.6 SEL-751 main relay outputs explanation

A. **Trip:** The Trip output from the low side SEL-751 is wired to the low side main CB trip coil and will close to retrip the breaker upon receipt of a trip signal from the SEL-487B bus relays. Note that the 101 CB Control Switch trip contact is wired directly to the CB trip coil rather than to a relay input and hence will not trip the breaker through the relay.

B. **Close (Manual and Auto):** The Close output from the low side SEL-751 is wired to the low side main CB close coil. The output will attempt to close the breaker for an operation of the reclose logic; upon receipt of a close signal from the SEL-487B bus relays while NAC and voltage checks are passed; or after a 10-second delay if the 101 CB Control switch is moved to the Close position while the NAC and voltage checks are passed. (See Input: Close from SEL-487B, above, for more information on voltage checks).

C. **SCADA Trip:** A signal received by the relay through a SCADA remote open command will close this output and attempt to open the breaker. The output is wired to the circuit breaker trip coil.

D. **SCADA Close:** As long as the 101 CB Control Switch is in the NAC position and voltage checks are passed, a signal received by the relay through a SCADA remote close command will close this output and attempt to close the breaker. The output is wired to the circuit breaker close coil. (See Input: Close from SEL-487B, above, for more information on voltage checks).

E. **Breaker Failure Trip to SEL-487B/R1:** If breaker failure times out in the low side SEL-751, the relay will send a breaker failure trip to the SEL-487B/R1 bus relay. 487B/R1 then trips and locks out the bus section breaker and the appropriate high side fault interrupter.

F. **Breaker Failure Trip to SEL-487B/R2:** If breaker failure times out in the low side SEL-751, the relay will send a breaker failure trip to the SEL-487B/R2 bus relay. 487B/R2 then trips and locks out the bus section breaker and the appropriate high side fault interrupter.

G. **Balanced Power Reverse Direction to SEL-487B/R1:** If the low side SEL-751 sees current flowing from the 12.47kV bus toward the 69kV bus/buses, the 751 will signal SEL-487B/R1 on this input. The signal is used as torque control in the 487B for balanced power trips.

H. **Balanced Power Reverse Direction to SEL-487B/R2:** If the low side SEL-751 sees current flowing from the 12.47kV bus toward the 69kV bus/buses, the 751 will signal SEL-487B/R2 on this input. The signal is used as torque control in the 487B for balanced power trips.

5.7 SEL-751 bus section relay protective elements explanation

A. **Current and Potential Inputs:** The SEL-751 bus section relay is primarily a control relay and does not perform any protective functions other than breaker failure trip signaling. Breaker failure timing relies on current inputs from CTs connected on the R side of the bus section breaker.

The relay also receives voltages from PTs connected on both sides the bus section breaker. Voltages from the R side are three phase to neutral, while the voltage coming from the L side is C phase to neutral only. These voltages are used to qualify breaker closing conditions. (See Input: Close from SEL-487B, above, for more information on voltage checks).

5.8 SEL-751 bus section relay inputs explanation

A. **52A Contact:** A 52A contact is required to supervise a number of operations, including Unlatch Trip, Unlatch Close, Reclose Initiate, Manual Closing, Slow Breaker Logic, and Trip and Close Coil Monitors. For example, the relay uses the 52A status to ensure that the breaker has opened before unlatching TRIP.

B. **Spring Charge Fail:** A low spring charge will typically open the normally closed contacts on 49MX. The relay Spring Charge Fail input will thus go low when spring charge is low and circuit breaker trouble logic will send an alarm to SCADA.

C. **Close from SEL-487B:** If the SEL-487B bus differential relays issue an auto transfer close to the bus section SEL-751 on this input, the bus section relay will check several conditions before attempting to close the breaker. To close, one side of the breaker must be Live (>95% nominal voltage) and the other side must be Dead (<25% nominal voltage), or the two sides must pass a synch check. Additionally, the 101 Circuit Breaker Control Switch must be in the normal after close (NAC) position to prevent closing the bus section if it has been locally tripped through the 101 switch.

D. **Trip from SEL-487B, No Reclose:** The SEL-487B bus differential relays can directly trip the bus section breaker. However, if the trip is required due to a breaker failure situation, or an auto transfer, the bus section SEL-751 will receive a signal from the 487Bs to retrip the breaker and drive reclosing to lockout. This prevents the bus section relay from attempting to reclose the breaker when an adjacent breaker has failed or for an auto transfer situation.

E. **Trip from SEL-487B, Reclose:** The SEL-487B bus differential relays can directly trip the bus section breaker. However, if the trip is required due to a bus differential operation, the bus section SEL-751 will receive a signal from the 487Bs to retrip the breaker and initiate breaker failure timing. Reclosing will not be blocked by this input, thus reclosing operations can begin normally if all other reclosing supervision conditions permit.

F. **Close Coil Monitor:** If voltage to the breaker close circuit is lost, the Close Coil Monitor input to the relay will go low. If this occurs while the breaker is open, circuit breaker trouble logic will send an alarm to SCADA. Note that there are multiple methods of obtaining the close coil voltage status, depending on the type of breaker in use.

G. **101 CB Control Switch Close:** Turning this switch to the Close position will start a 10 second timer in the relay. Upon timeout, the relay will attempt to close the breaker as long as the voltage check is passed (see Close from 487B, above), and the 101 switch is back in the Normal After Close (NAC) position.

H. **Input Fuse Alarm:** If DC input voltage is lost to the relay, circuit breaker trouble logic will send an alarm to SCADA.

I. **Trip Coil Monitor:** The Trip Coil Monitor indicates whether the circuit breaker trip coil is continuous/ready to trip while the breaker is closed. If the trip coil is not ready to trip (TCM input is low) and the breaker is closed, circuit breaker trouble logic in the relay will send an alarm to SCADA. Note that there are multiple methods of obtaining the trip coil ready status, depending on the type of breaker in use.

J. **101 NAC Supervisory Disable:** The 101 Circuit Breaker Control Switch must be in the Normal After Close (NAC) position for the bus section SEL-751 to allow reclosing, a SCADA close, a local control switch close, or a close from the SEL-487B bus differential relays.

5.9 SEL-751 bus section relay outputs explanation

A. **Trip:** The Trip output from the bus section SEL-751 is wired to the breaker trip coil and will close to retrip the breaker upon receipt of a trip signal from the SEL-487B bus relays. Note that the 101 CB Control Switch trip contact is wired directly to the CB trip coil rather than to a relay input and hence will not trip the breaker through the relay.

B. **Close (Manual and Auto):** The Close output from the bus section SEL-751 is wired to the CB close coil. The output will attempt to close the breaker for an operation of the reclose logic;

upon receipt of a close signal from the SEL-487B bus relays while NAC and voltage checks are passed; or after a 10-second delay if the 101 CB Control switch is moved to the Close position while the NAC and voltage checks are passed. (See Input: Close from SEL-487B, above, for more information on voltage checks).

C. **SCADA Trip:** A signal received by the relay through a SCADA remote open command will close this output and attempt to open the breaker. The output is wired to the circuit breaker trip coil.

D. **SCADA Close:** As long as the 101 CB Control Switch is in the NAC position and voltage checks are passed, a signal received by the bus section SEL-751 through a SCADA remote close command will close this output and attempt to close the breaker, as long as the breaker is open. The output is wired to the circuit breaker close coil. (See Input: Close from SEL-487B, above, for more information on voltage checks).

E. **Breaker Failure Trip to SEL-487B/R1:** If breaker failure times out in the bus section SEL-751, the relay will send a breaker failure trip to the SEL-487B/R1 bus relay. The 487B/R1 relay then trips and locks out the main low side breakers.

F. **Breaker Failure Trip to SEL-487B/R2:** If breaker failure times out in the bus section SEL-751, the relay will send a breaker failure trip to the SEL-487B/R2 bus relay. The 487B/R2 relay then trips and locks out the main low side breakers.

6. Feeder Protection Examples

6.1 Purpose statement

A. Several examples of different feeder configurations are included in this section, each demonstrating the general procedure for applying the protection standards.

B. In reality it is impossible to apply protection standards in a truly uniform manner as every feeder has unique conditions, be they fault coverage, coordination with PPL or customer equipment, or reliability concerns. These examples are provided to show the decision process for how the general protection principles can be applied in a specific manner, customizing each feeder to maximize effectiveness.

6.2 Phase Overcurrent Fault vs. Load Coverage

A. Phase overcurrent elements must be balanced between a minimum level of fault coverage and maximum circuit loading. In all cases the phase overcurrent pickup is set at a minimum of 1.5x the lowest short circuit current within the protective devices zone. It is therefore possible the protective setting will encroach on load and limit the feeder loadability. This is an unavoidable byproduct of all protective schemes, and the circuit must be planned and operated accordingly.

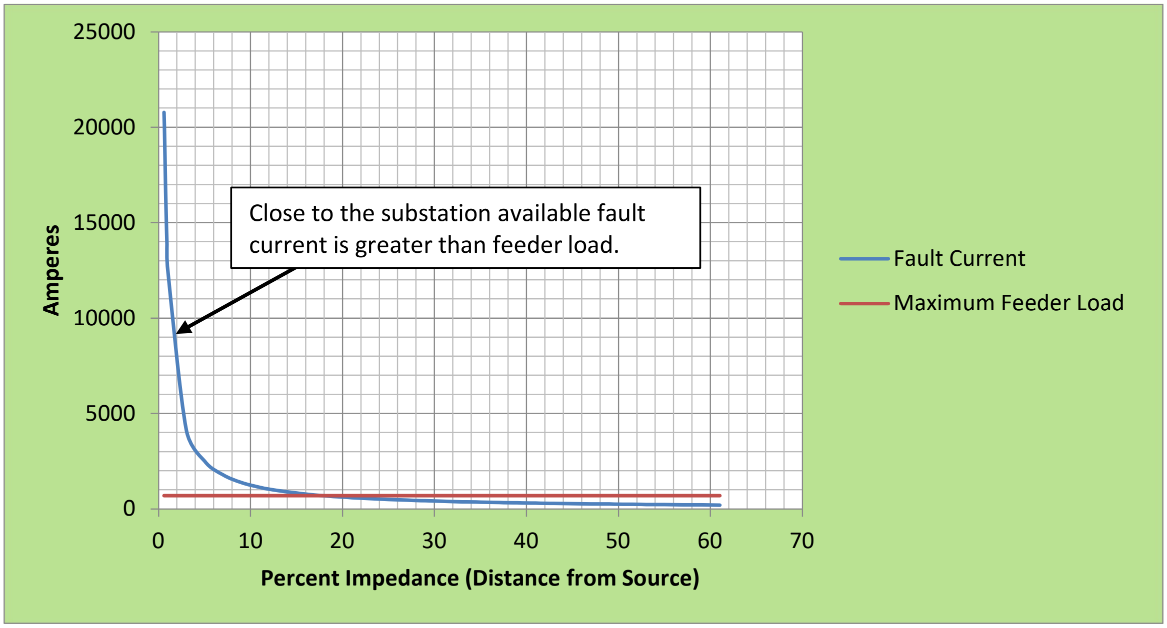
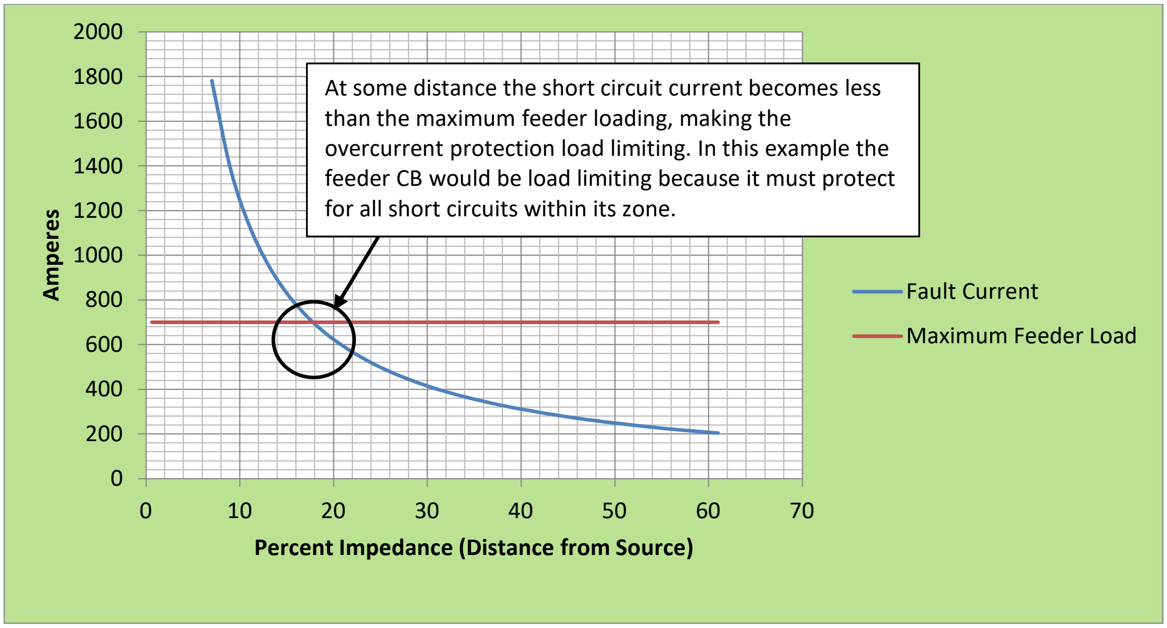
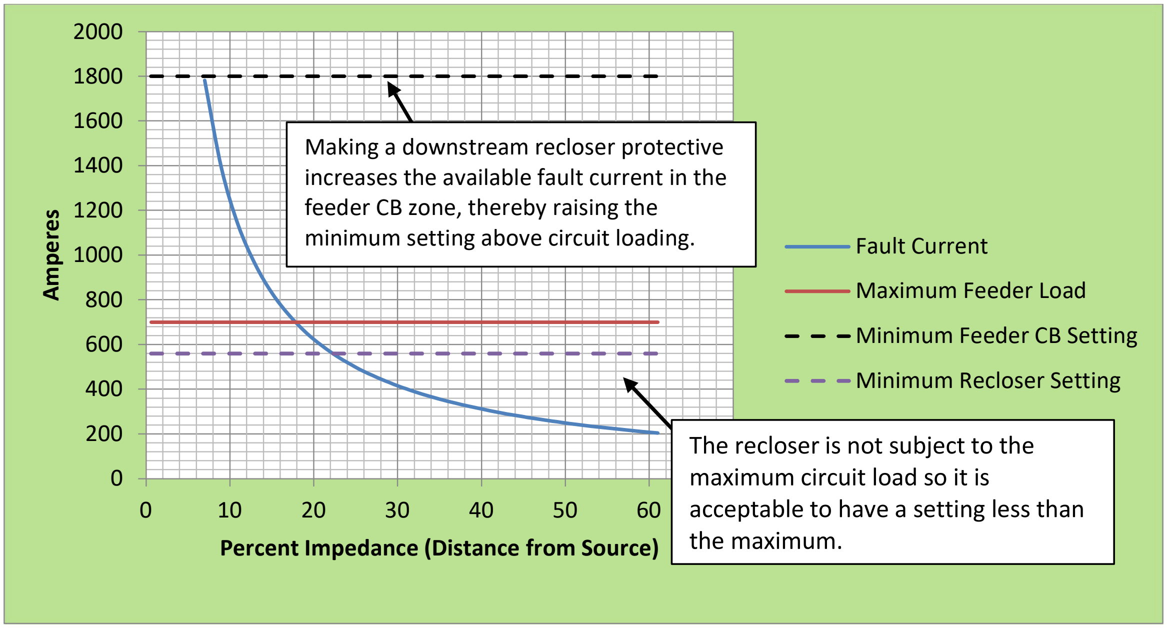


Figure 6-1: Typical Feeder Fault Current vs. Typical Maximum Circuit Loading



At some distance the short circuit current becomes less than the maximum feeder loading, making the overcurrent protection load limiting. In this example the feeder CB would be load limiting because it must protect for all short circuits within its zone.

Figure 6-2: Feeder Load vs. Overcurrent Pickup Overlap

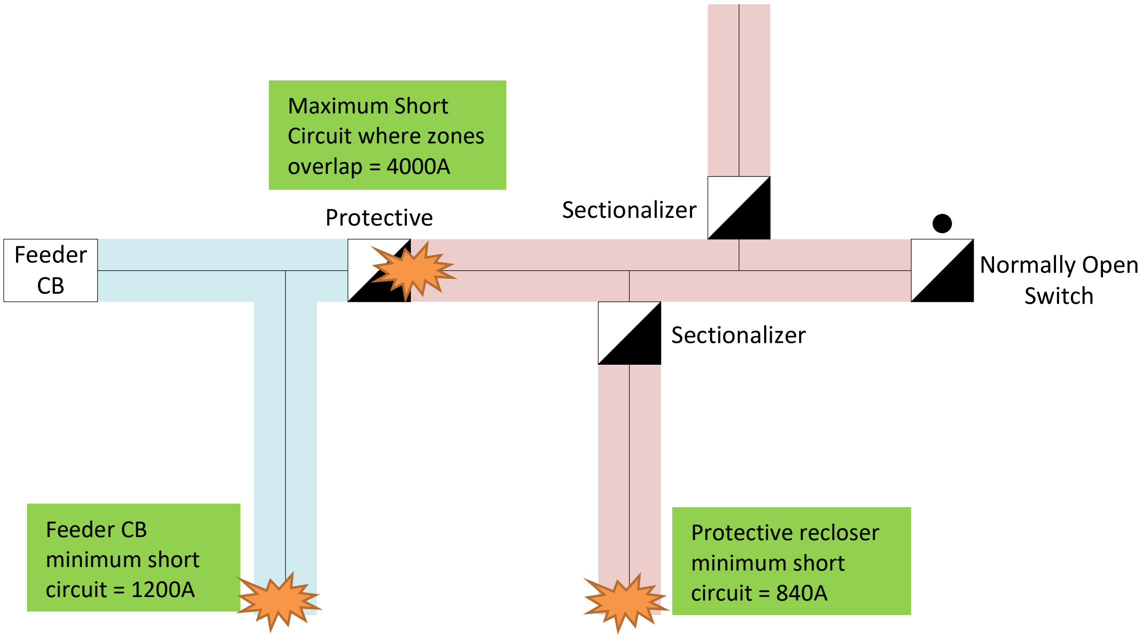


Making a downstream recloser protective increases the available fault current in the feeder CB zone, thereby raising the minimum setting above circuit loading.

The recloser is not subject to the maximum circuit load so it is acceptable to have a setting less than the maximum.

Figure 6-3: Feeder CB Minimum Setting vs. Recloser Minimum Setting

6.3 Example 1: Basic Feeder Configuration



Protection Summary

Zones of Protection

- The feeder CB is always protective. Its zone covers the blue highlighted area.
- The first recloser is made protective to provide an automatic sectionalizing point at approximately the mid-point of the feeder. Its zone is the red highlighted area.
- This divides the feeder into two distinct protective zones, which is an advantage because it allows the feeder overcurrent pickup to be set above the maximum feeder load while still providing the maximum sensitivity for faults within its zone of protection. The protective recloser then provides fault coverage for the remainder of the feeder.

Fuse Savings

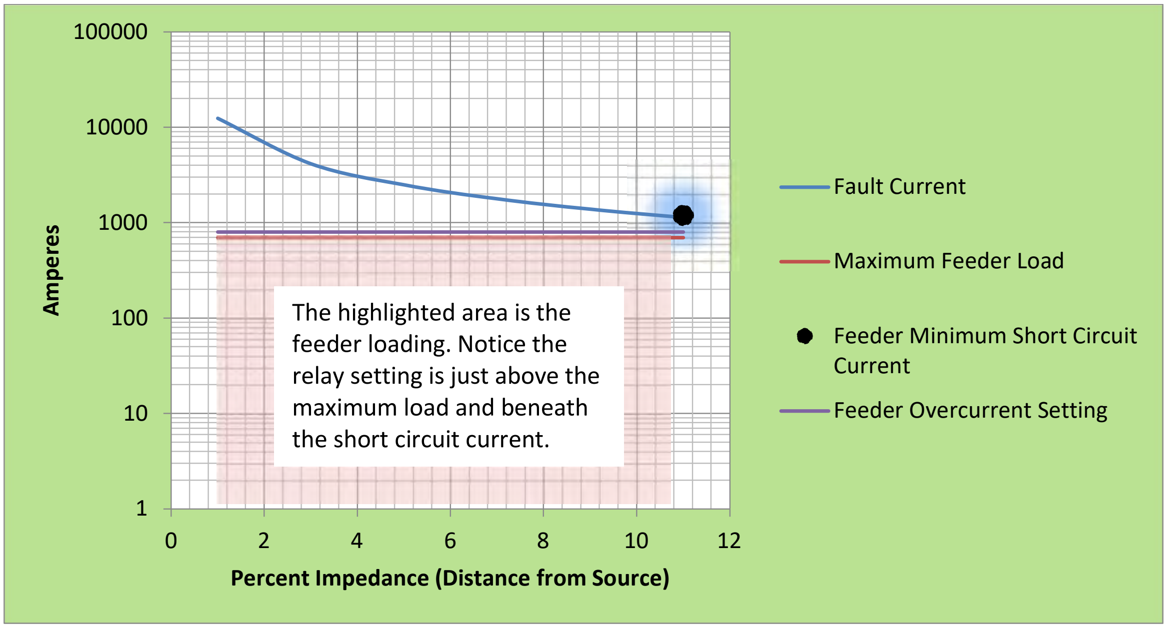
- The feeder CB zone does not provide fuse savings.
- The protective recloser provides fuse savings for its entire zone. One fast fuse savings ground trip would be enabled. This fulfills the fuse savings principle.

Coordination

- The feeder CB instantaneous trips are set short of the first protective recloser wherever possible.
- The feeder CB and protective recloser are coordinated on delayed curves at the maximum available short circuit current where the zones overlap. This fulfills the principle of clearing faults in the fastest possible time.
- Both downstream tapped reclosers are made sectionalizers to eliminate the coordination process with the upstream protective reclosers. This fulfills both the principle of isolating faults with the nearest upstream automatic sectionalizing device and clearing faults in the fastest possible time.

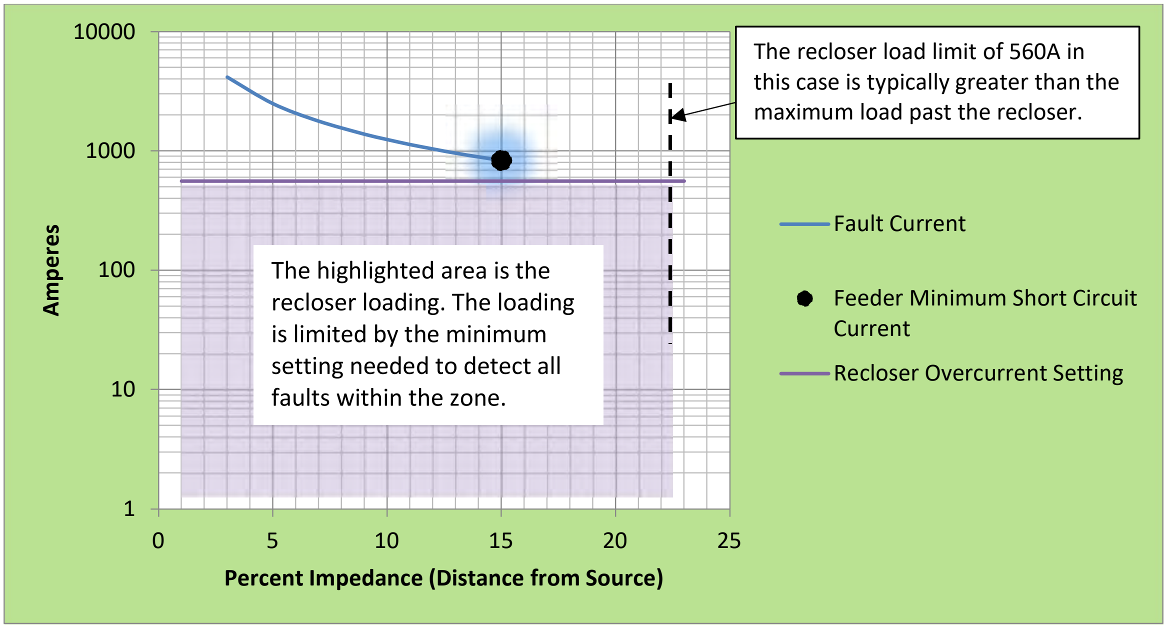
Safety

- All electronic reclosers have hot line tag available. The crew should white tag the nearest protective device upstream from their work location.



The highlighted area is the feeder loading. Notice the relay setting is just above the maximum load and beneath the short circuit current.

Figure 6-4: Example 1 Feeder CB Minimum Fault Current and Overcurrent vs. Feeder Load

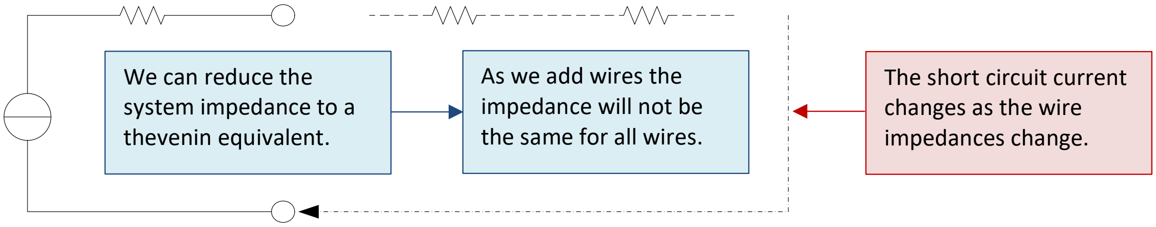


The recloser load limit of 560A in this case is typically greater than the maximum load past the recloser.

The highlighted area is the recloser loading. The loading is limited by the minimum setting needed to detect all faults within the zone.

Figure 6-5: Example 1 Recloser Minimum Fault Current vs. Overcurrent Setting

A. From this example we can conclude that overcurrent protection can be load limiting. As the distance from the source is increased the circuit impedance increases, reducing the available short circuit current at any given location. Further, as the study point is moved away from the feeder source the conductor size will decrease, sometimes quite dramatically on taps, causing a non-linear increase in circuit impedance and thus a large reduction in available fault current.



We can reduce the system impedance to a thevenin equivalent.

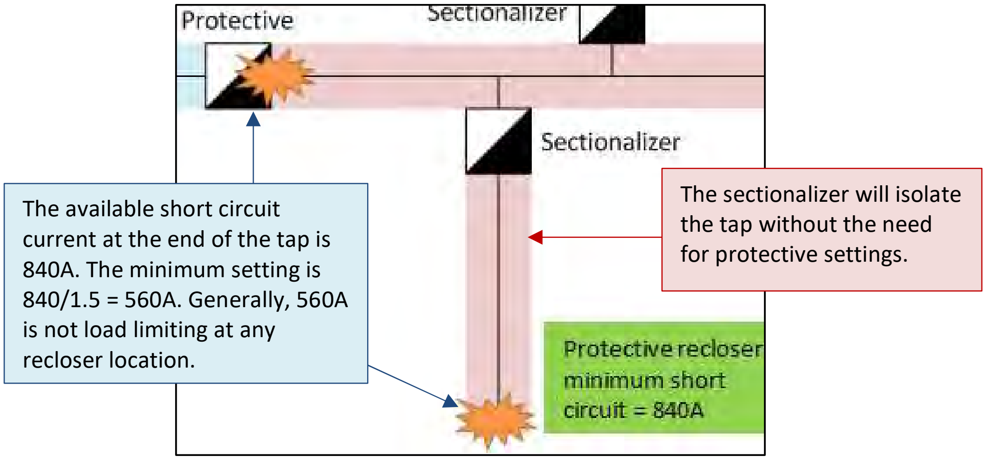
As we add wires the impedance will not be the same for all wires.

The short circuit current changes as the wire impedances change.

Figure 6-6: Thevenin Equivalent Circuit

B. We can also conclude that making one recloser protective, where possible, is the most efficient and effective course of action. For this example the available fault current on the taps is high enough that setting the midline recloser to be protective will not cause it to be load limiting, and we can reduce the number of operations to save a fuse to one trip by the protective recloser, rather than multiple overreaching trips by multiple protective reclosers.

C. Sectionalizers eliminate the need for coordination and are not affected by load so they are logical choices to automatically isolate faults on the taps. That is, for faults on the taps the protective recloser would trip and the sectionalizer would count, and when the maximum count is reached the sectionalizer will open, isolating the tap and keeping the rest of the customers past the protective recloser in service.

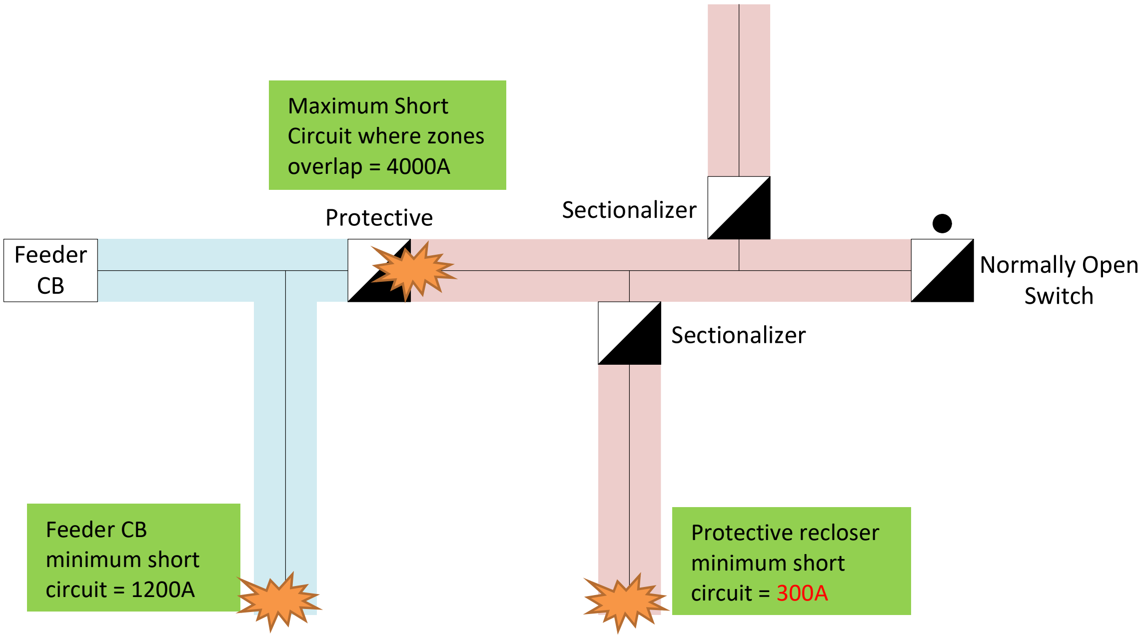


The available short circuit current at the end of the tap is 840A. The minimum setting is 840/1.5 = 560A. Generally, 560A is not load limiting at any recloser location.

The sectionalizer will isolate the tap without the need for protective settings.

Figure 6-7: Overcurrent Reach

6.4 Example 2: Evolution of Example 1



Protection Summary

Zones of Protection

- There is a subtle but important difference in this example – the available fault current at the end of the tap has changed to 300A. This could result from increased tap length and/or small wire, which has higher impedance.
- If we were to leave the midline recloser protective it would now be load limiting. That is, the minimum setting required to detect a fault at the end of the tap is 300A/1.5=200A. A setting 0f 200A would almost certainly be load limiting for a midline device.
- Therefore, on this circuit it would better to make the midline device a switch and the tapped reclosers protective, providing coverage to the taps without being load limiting at the midline.

Fuse Savings

- The feeder CB zone does not provide fuse savings.
- The tapped reclosers would each provide a single fast trip.
- The midline recloser would not provide any fuse savings, meaning all fuse savings would be eliminated for taps fed from the main three phase backbone. This may or may not be desirable depending on the reliability of the circuit.

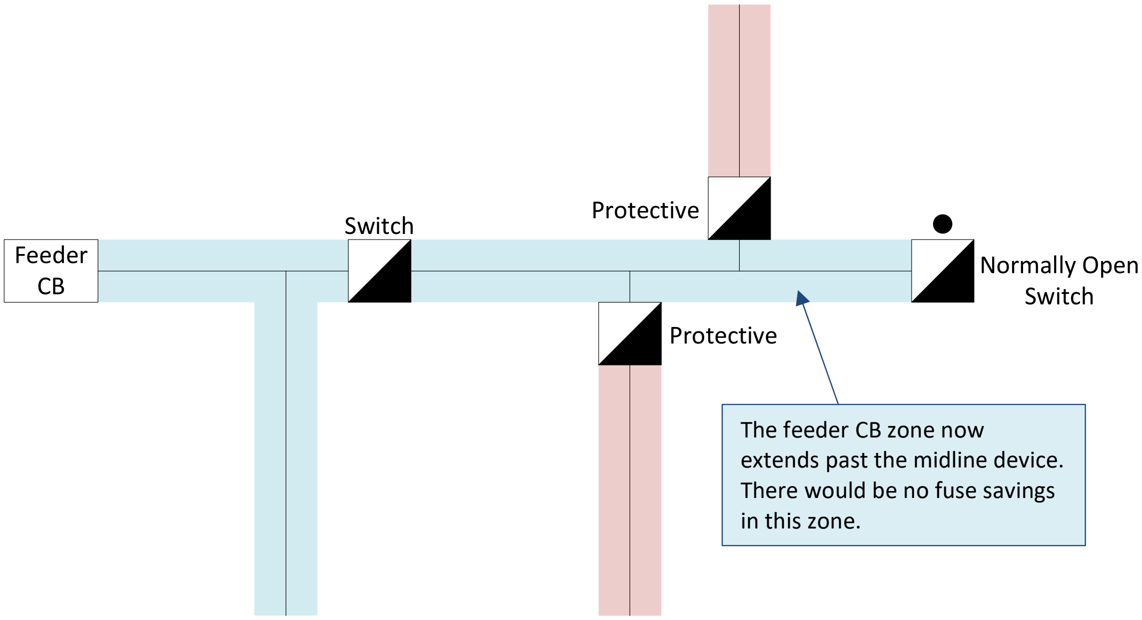
Coordination

- The feeder CB instantaneous trips are set short of the first protective recloser(s) wherever possible.

Safety

- The crew should white tag the nearest protective device upstream from their work location.

The new circuit configuration would look as follows:



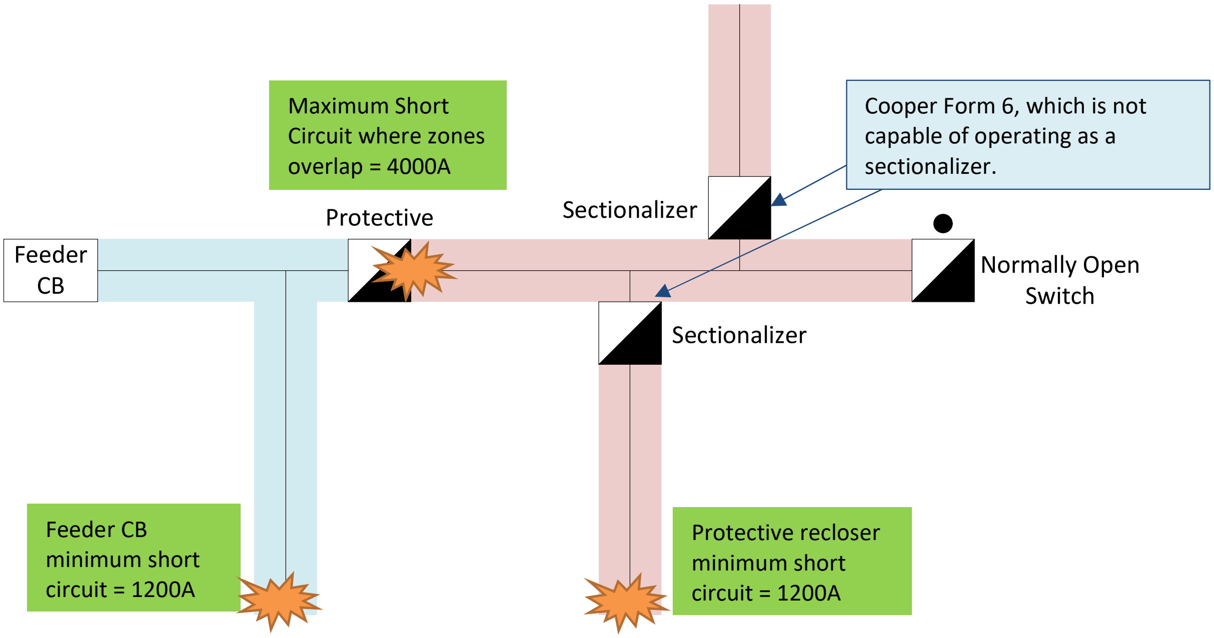
The feeder CB zone now extends past the midline device. There would be no fuse savings in this zone.

A. From this example we can conclude that a simple variation in wire impedance or length can cause the operation of the circuit to be drastically reconfigured. The single tap that has low available fault current makes it impossible for the midline device to detect all faults within its zone and not be load limiting, therefore the recloser on that tap must be made protective.

B. Making the tapped reclosers protective causes them to miscoordinate with the midline device, requiring that device to be made a switch. This forces all of the protection on the feeder CB for the zone that would have been covered by the midline recloser.

C. The feeder CB does not provide fuse savings, and since the midline recloser has been made a switch it also does not provide fuse savings. This means any single phase taps in the blue zone would not have fuse savings – that is, any fault past those fuses will immediately operate the fuse without a trip from the feeder CB. In this kind of circuit configuration the loss of fuse savings is unavoidable.

6.5 Example 3: Equipment Variation with Example 1



Protection Summary

Zones of Protection

- There is another subtle variation in this circuit – the available fault current at the end of the tap is now 1200A. This means it is once again possible to set the midline recloser as a protective device and not be load limiting.
- However, let us consider that the tapped reclosers are not capable of sectionalizer operation – perhaps they are Cooper Form 6 devices which do not have that function available.
- The result is that all the tapped reclosers must be made protective. Further, if it was desired to have the midline device be protective, perhaps for fuse savings, or required for zone coverage, we would need to coordinate all three devices in three separate zones.

Fuse Savings

- The feeder CB zone does not provide fuse savings.
- The tapped reclosers would have the fast trip blocked.
- The midline recloser would provide fuse savings for the whole circuit past its location. This prevents multiple operations to save the same fuse, eliminating the overlapping fast trips that cannot be coordinated.

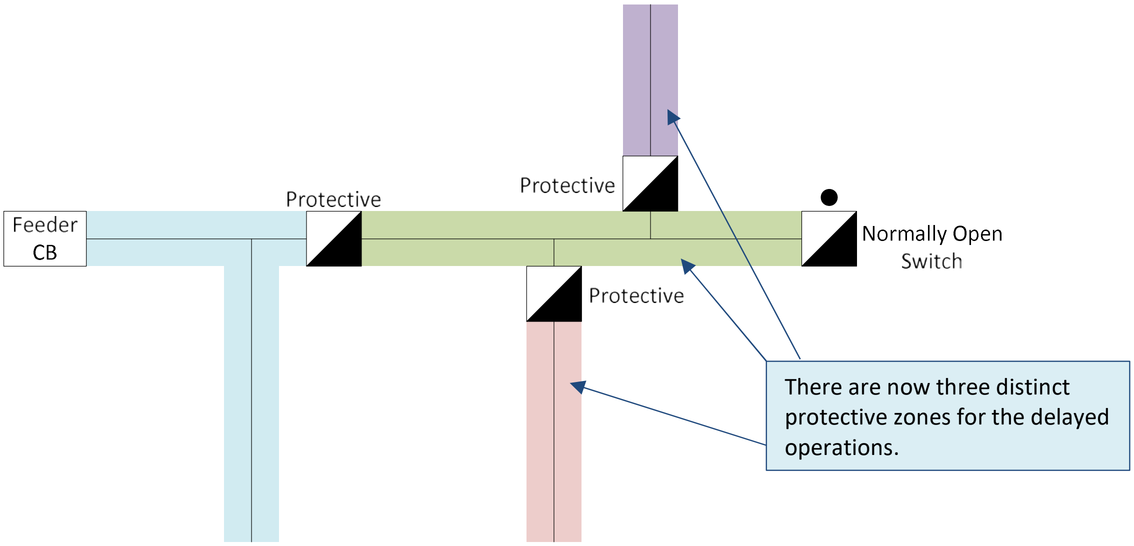
Coordination

- The feeder CB instantaneous trips are set short of the first protective recloser(s) wherever possible.
- The protective devices are coordinated on delayed curves.
- Fast curves cannot be coordinated.

Safety

- The crew should white tag the nearest protective device upstream from their work location.

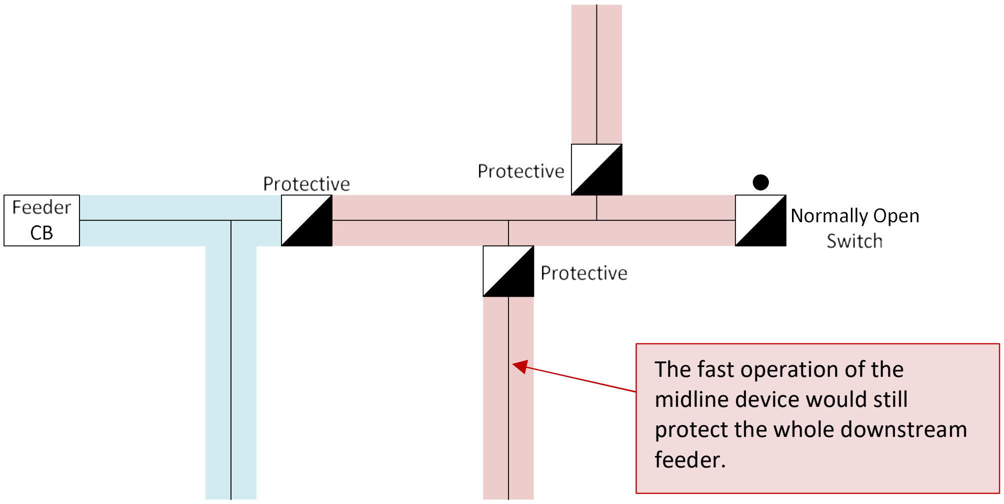
The reconfigured circuit would look as follows:



There are now three distinct protective zones for the delayed operations.

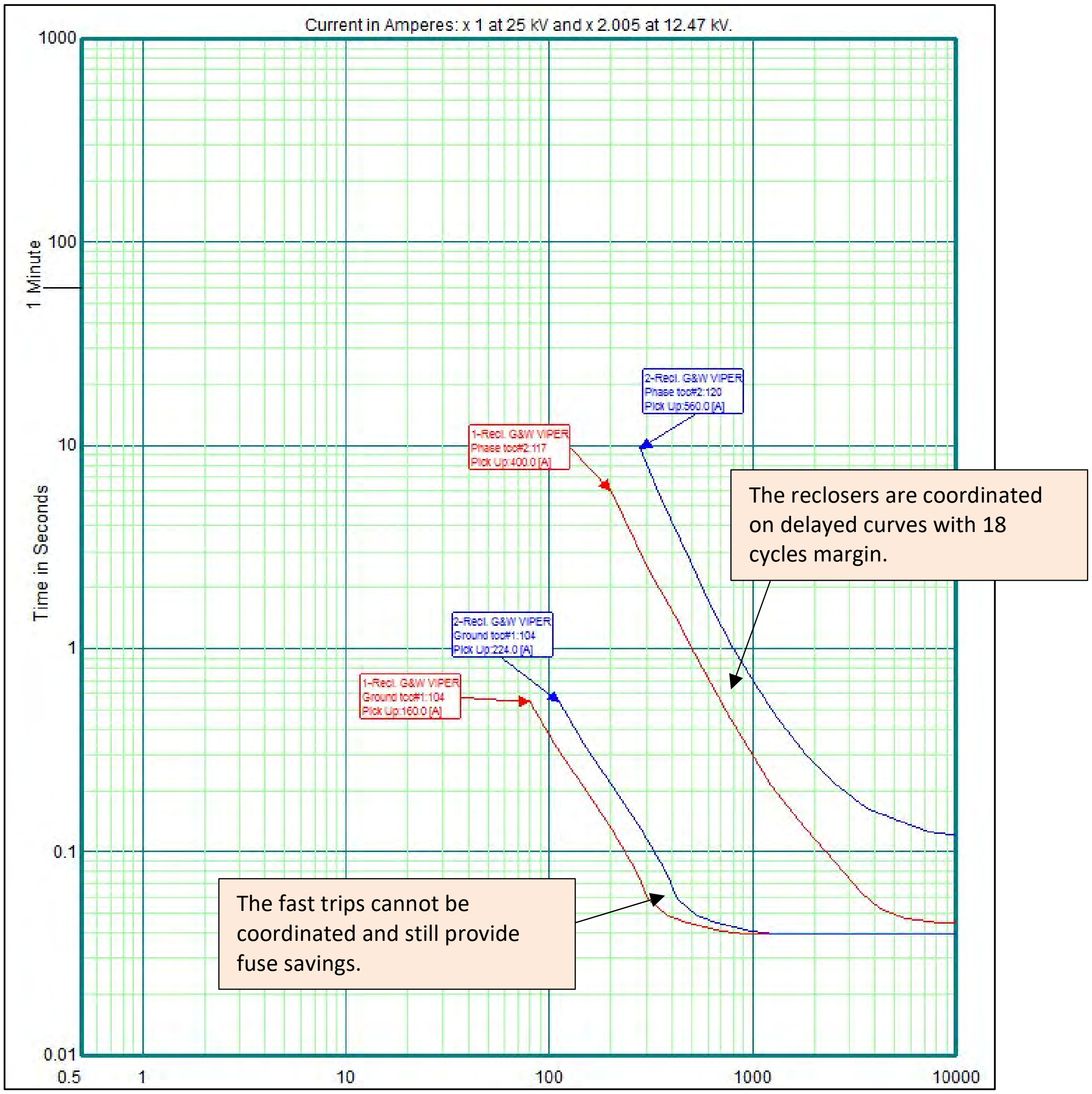
A. From this example we can conclude that equipment limitations can dictate the operation of the circuit. The Form 6 reclosers cannot be made sectionalizers so they must be coordinated as a protective device which causes a total change in how the protection philosophy is applied.

B. However, it is not desirable to overlap zones so the fast trips are eliminated on the tapped reclosers but maintained on the midline device, providing fuse savings for the feeder without overlapping zones and creating nuisance trips.



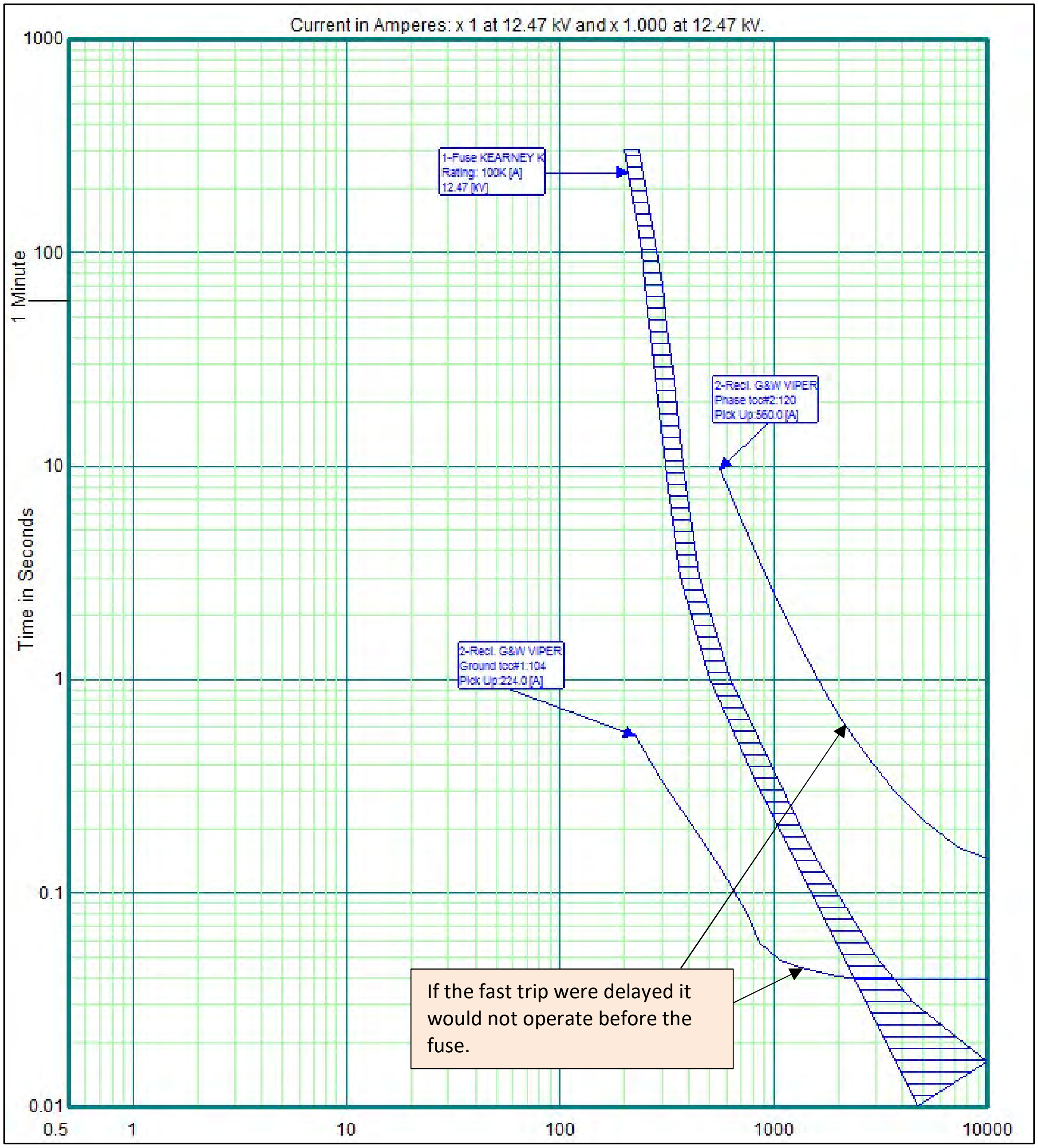
The fast operation of the midline device would still protect the whole downstream feeder.

C. Fast trips must be nearly instantaneous in operation to save fuses. Typical operating time is 2.75 cycles or .0458 seconds. Coordination margins are at least 18 cycles or 0.30 seconds, making it impossible to coordinate fast trips and still save fuses.



The reclosers are coordinated on delayed curves with 18 cycles margin.

The fast trips cannot be coordinated and still provide fuse savings.



If the fast trip were delayed it would not operate before the fuse.

Division 1-27

Request:

Provide a copy of each feeder Time Current Coordination Curve ("TCC") showing the existing and proposed new devices and device types and settings.

Response:

As stated in the response to Division 1-25, Rhode Island Energy ("RIE" or the "Company") does not believe a systemwide fault current study is necessary for general utility practice as it could result in resource inefficiencies. Therefore, a copy of each feeder Time Current Coordination Curve ("TCC") showing existing and proposed devices and device types and settings is not available.

Unless the Company identifies a complex coordination issue that requires coordination reviews during study phases, like distributed generation interconnections, it typically completes coordination reviews during early stages of execution.

Two feeders have been selected to demonstrate the TCC curves[1]. The first feeder is the 34F1 feeder out of Chopmist substation, which represents a long rural circuit on which all the devices are currently existing. The second feeder is the 18F5 feeder out of the Johnston substation which represents a short urban feeder, which, for this example, adds an additional main line recloser (275508014). In this example the station breaker and first main line recloser did not require additional setting changes to accommodate the proposed device.

Attachment DIV 1-27 shows a coordination table for each circuit. The 34F1 table shows a coordination issue between two fuses, a 25K and 15K fuse. The Company accepts this level of miscoordination in order to limit circuit exposure, improve reliability, and provide better end-of-line fault sensing. It is accepted good utility practice to design a protective system that forces miscoordination between the furthest devices and least number of customers. The 18F5 table shows an additional Grid Modernization Plan recloser with no coordination issues.

Please see the figures below for additional information on the selected feeders.

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[1] After notifying the Division that the Company does not have a copy of each feeder, the Division updated its request asking the Company to provide two examples of RIE's existing work for a short feeder and a long rural feeder.

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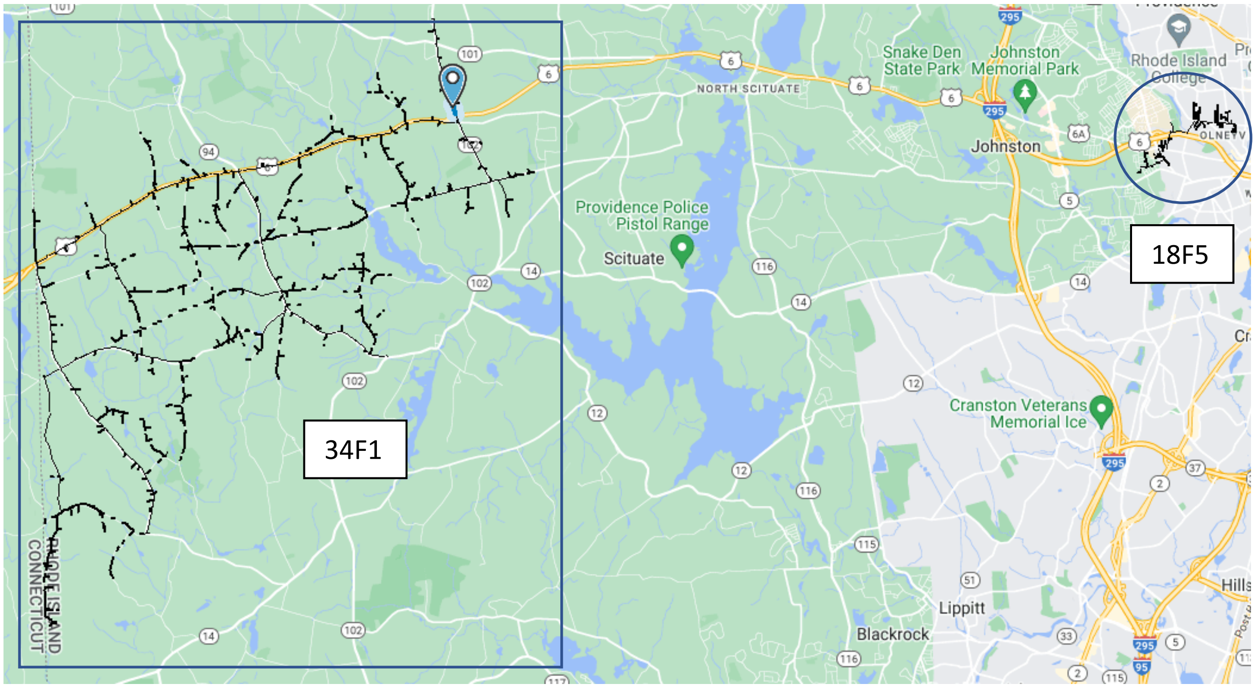
Figure 1 – Selected Feeders



Prepared by or under the supervision of: Ryan Constable

<u>Division 1-27, page 3</u>

Figure 2 – 34F1 TCC

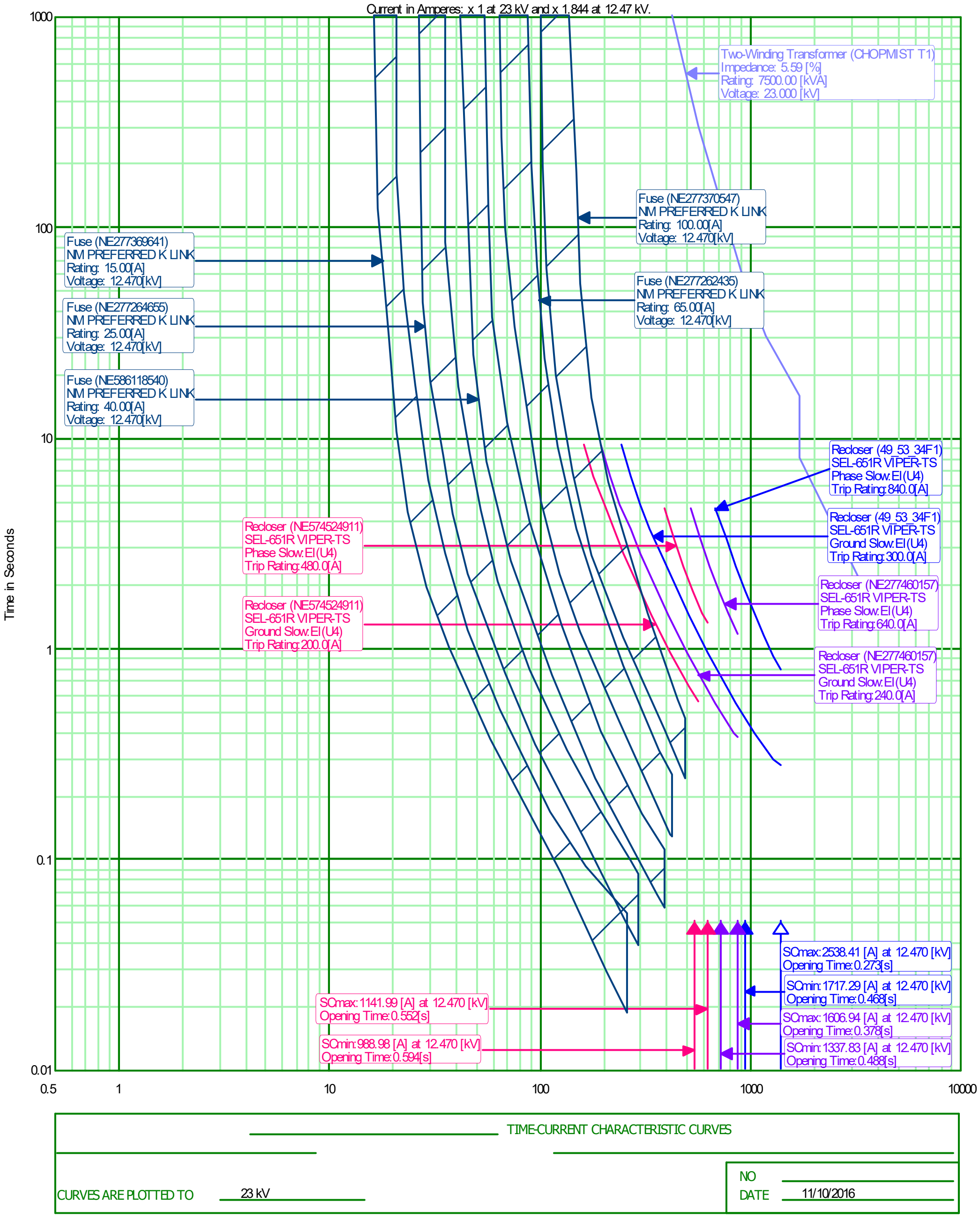


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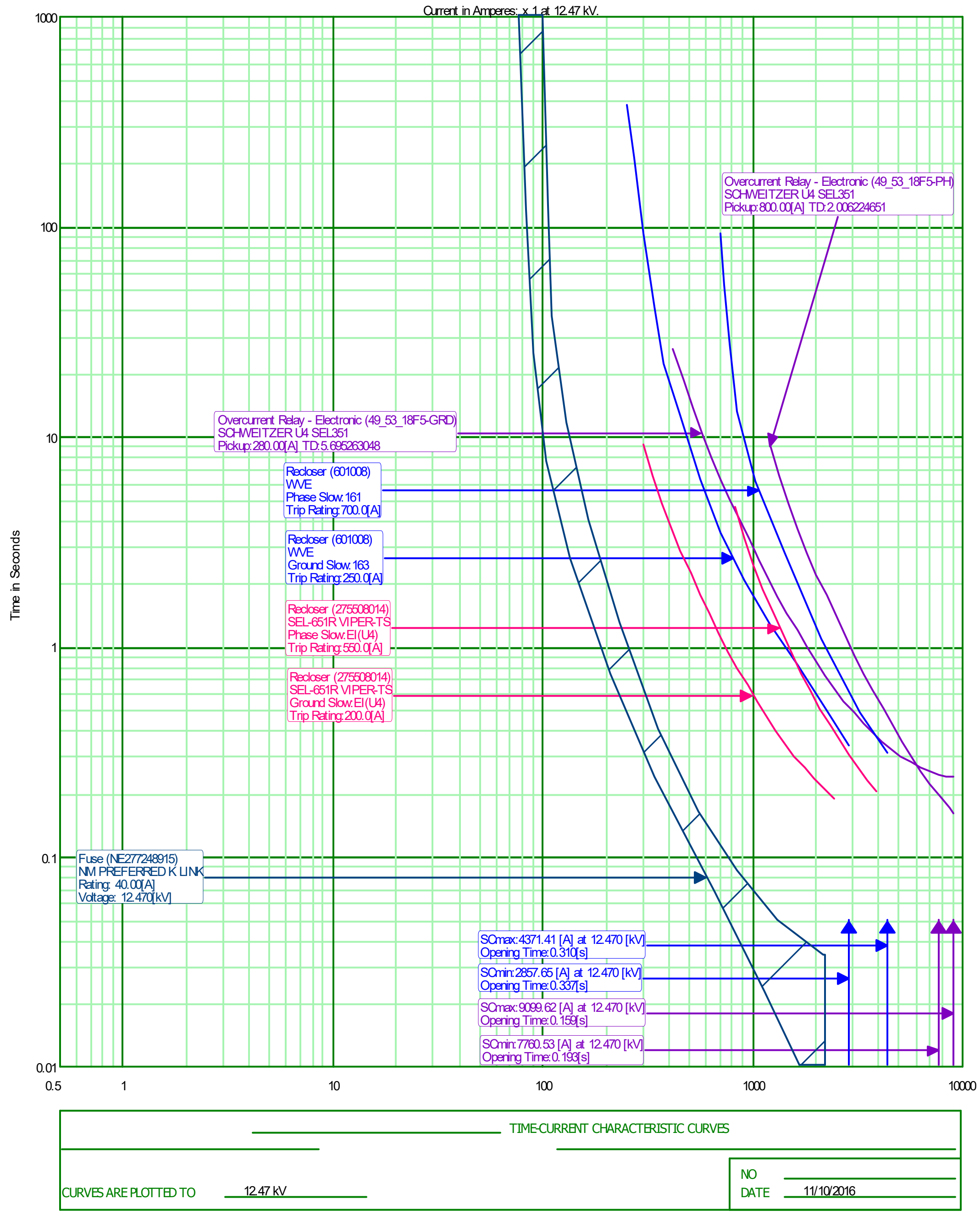
Figure 3 – 18F5 TCC



Prepared by or under the supervision of: Ryan Constable

Network Id	Upstream Device Number	Upstream Device Type	Protection	Upstream Pickup	Upstream Curve / Rating (A)	Customers between devices	Downstream Device Number	Downstream Device Type	Downstream Pickup	Downstream Curve / Rating (A)	Protection Range Minimum (A)	Protection Range Maximum (A)	Non-coordination point (A)	Coordination?	Description	TCC Curves
49_53_34F1	49_53_34F1	Recloser	Phase	840.00	EI(U4)	71	NE277460157	Recloser	640.00	EI(U4)	1337.83	1606.94	n/a	Yes		**Display**
49_53_34F1	49_53_34F1	Recloser	Ground	300.00	EI(U4)	71	NE277460157	Recloser	240.00	EI(U4)	1582.80	1582.80	n/a	Yes		**Display**
49_53_34F1	NE277460157	Recloser	Phase	640.00	EI(U4)	179	NE574524911	Recloser	480.00	EI(U4)	988.98	1141.99	n/a	Yes		**Display**
49_53_34F1	NE277460157	Recloser	Ground	240.00	EI(U4)	179	NE574524911	Recloser	200.00	EI(U4)	1033.53	1033.53	n/a	Yes		**Display**
49_53_34F1	NE574524911	Recloser	Phase	480.00	EI(U4)	151	NE277370547	Fuse		100	785.80	907.37	n/a	Yes		**Display**
49_53_34F1	NE574524911	Recloser	Ground	200.00	EI(U4)	151	NE277370547	Fuse		100	839.37	839.37	n/a	Yes		**Display**
49_53_34F1	NE277370547	Fuse	Phase		100	232	NE277262435	Fuse		65	567.58	776.14	n/a	Yes		**Display**
49_53_34F1	NE277370547	Fuse	Ground		100	232	NE277262435	Fuse		65	567.58	661.61	n/a	Yes		**Display**
49_53_34F1	NE277262435	Fuse	Phase		65	38	NE586118540	Fuse		40	566.06	713.52	n/a	Yes		**Display**
49_53_34F1	NE277262435	Fuse	Ground		65	38	NE586118540	Fuse		40	566.06	566.06	n/a	Yes		**Display**
49_53_34F1	NE586118540	Fuse	Phase		40	12	NE277264655	Fuse		25	478.11	542.07	n/a	Yes		**Display**
49_53_34F1	NE586118540	Fuse	Ground		40	12	NE277264655	Fuse		25	478.11	542.07	n/a	Yes		**Display**
49_53_34F1	NE277264655	Fuse	Phase		25	21	NE277369641	Fuse		15	439.54	476.20	n/a	No	Coordination criterion not respected	**Display**
49_53_34F1	NE277264655	Fuse	Ground		25	21	NE277369641	Fuse		15	439.54	476.20	n/a	No	Coordination criterion not respected	**Display**

Network Id	Upstream Device Number	Upstream Device Type	Protection	Upstream Pickup	Upstream Curve / Rating (A)	Customers between devices	Downstream Device Number	Downstream Device Type	Downstream Pickup	Downstream Curve / Rating (A)	Protection Range Minimum (A)	Protection Range Maximum (A)	Non-coordination point (A)	Coordination?	Description	TCC Curves
49_53_18F5	49_53_18F5	Breaker	Phase	800	R U4 SEL351	562	601008	Recloser	700	161	2857.65	4371.41	n/a	Yes		**Display**
49_53_18F5	49_53_18F5	Breaker	Ground	280	R U4 SEL351	562	601008	Recloser	250	163	2857.65	2857.65	n/a	Yes		**Display**
49_53_18F5	601008	Recloser	Phase	700	161	453	275508014	Recloser	550	EI(U4)	2473.11	3872.86	n/a	Yes		**Display**
49_53_18F5	601008	Recloser	Ground	250	163	453	275508014	Recloser	200	EI(U4)	2473.11	2473.11	n/a	Yes		**Display**
49_53_18F5	275508014	Recloser	Phase	550	EI(U4)	346	NE277248915	Fuse		40	2208.39	2208.39	n/a	Yes		**Display**
49_53_18F5	275508014	Recloser	Ground	200	EI(U4)	346	NE277248915	Fuse		40	2208.39	2208.39	n/a	Yes		**Display**

Yellow Highlight - New Recloser

Division 1-28

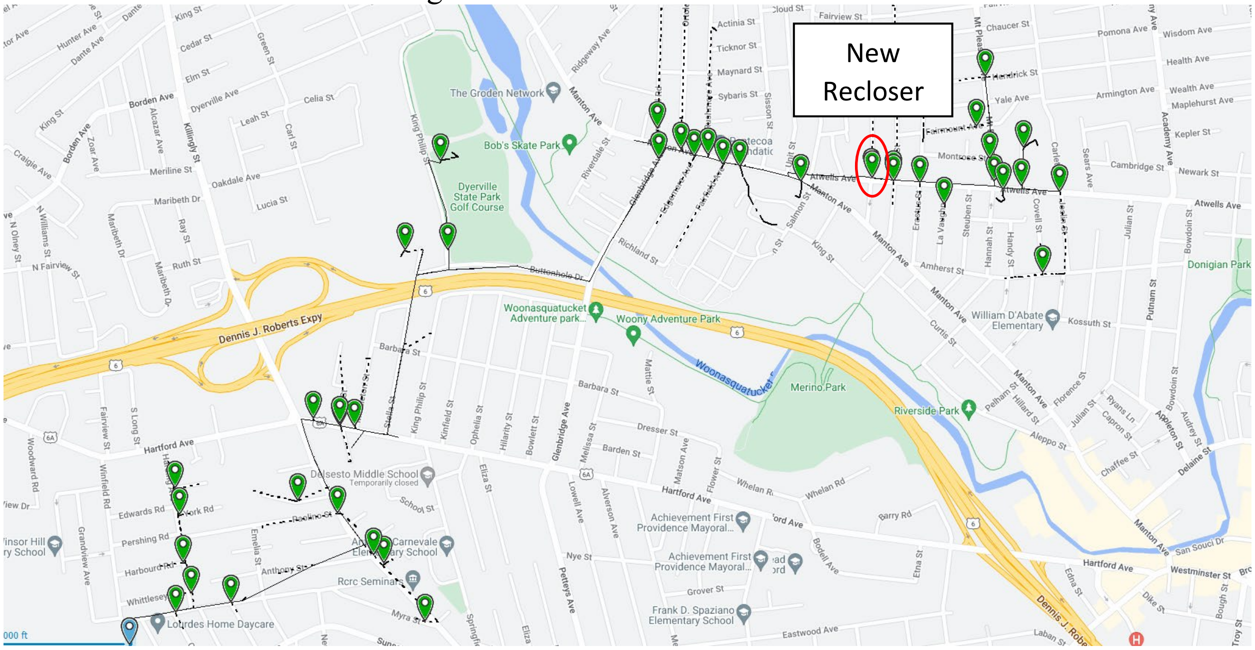
Request:

Provide individual feeder circuit maps showing the existing and proposed protective device changes, and additions.

Response:

Individual feeder maps showing the existing and proposed protective device changes are not available. Although various programs and systems, such as CYME and EMS, can create maps with protective devices, the Company does not produce such maps to perform protective coordination and device placement. Instead, the programs are used directly. Also, device placement is still being determined. An example CYME diagram, shown in Figure 1, below, is provided for the 18F5 feeder out of the Johnston substation. The response to DIV 1-27 shows the time current coordination curve for this circuit with the new recloser.

Figure 1 – 18F5 Protective Devices


New Recloser

Division 1-29

Request:

Provide a detailed discussion of how RIE is meeting the IEEE standard C32-230 recommendations in its new recloser addition program.

Response:

The Company understands this request to refer to the C37-230 recommendations and provides this response based on that understanding.

The C37-230 is a recommended guideline and not a formal standard for compliance. IEEE and the industry recognize the standard is wholly voluntary. Regardless, Rhode Island Energy finds value in IEEE C37-230, as it does all IEEE documents and generally meets the guideline.

The new recloser investments are driven by reliability needs -- not topics contained within C37-230. However, when the reclosers are installed, they will be installed with the following considerations aligned with C37-230:

- Check for clearing end-of line fault current.
- Overcurrent settings will be set above the load limit of the circuit.
- Overcurrent time dial should be selected for coordination with largest fuse size.
- The detection of ground faults takes priority over coordination.
- Coordination margin will be maintained according to Company procedures.

Personnel at Rhode Island Energy have been incorporating such details into their coordination studies for decades – well prior to the first version of C37-230 in 2007.

The details of the topics above may be changing as Rhode Island Energy evaluates and potentially adopts PPL's standards. Further protection coordination details are included in the response to DIV 1-26.

Prepared by or under the supervision of: Ryan Constable

Division 1-30

Request:

Provide an updated 3V0 chart in executable format, specifically identifying projects in the FY 2023 ISR Plan (see response to R-III-2 in FY2022 ISR Plan).

Response:

An updated 3V0 chart is included below along with an excel file as Attachment DIV 1-30.

Substation	Project Estimate		Actual Spend through 09/30/22		Remaining FY23 forecast		3V0 Targeted Completion Date	3V0 Actual Completion Date
	Capex	Opex	Capex	Opex	Capex	Opex		
Peacedale	$427,500	$22,500	$129,217	$0	$231,359	$0	03/31/22	Projected 03/08/23
Langworthy	$275,000	$25,000	$128,530	$0	$215,710	$0	03/31/22	Projected 01/09/23
Wampanoag	$95,000	$5,000	$0	$0	$79,016	$1,320	03/31/23	Projected 03/29/23
Clarkson St	$95,000	$5,000	$1,031	$0	$73,275	$3,112	03/31/23	Projected 01/16/23
TOTAL FORECAST FY23					$599,360	$4,432		

Prepared by or under the supervision of: Ryan Constable

Division 1-31

Request:

Provide complete details on the Nasonville substation and outage, including but not limited to the following:

a. Substation characteristics including location, area served, voltages, transformer arrangement, feeders, etc.

b. Description of the incident including date, time, weather conditions, and cause.

c. Estimated substation and feeder loading at time of incident compared to substation/circuit normal and emergency ratings.

d. Number of customers impacted.

e. Restoration activities and timeline of customer count and load restored.

f. A detailed circuit diagram indicating all interconnected feeders and what loads were transferred to adjacent substations

g. The duration of time it took for the Company to place a mobile transformer/substation in service to serve load and how much of the load was served from the mobile.

h. Indicate for each adjacent circuit each smart device and device location that provided increased visibility for the event, loads and DG capability.

i. Show each DG and its location that was called upon to serve load during the event and explain in detail what communications the Company had through telemetry to allow it to know the DG output in real time.

Division 1-31, page 2

Response:

(a)

- Nasonville substation (#127) is located at 445 Douglas Pike, Smithfield, RI. Nasonville Substation serves the northwestern part of Rhode Island. Areas served include portions of North Smithfield, Burrillville, Gloucester, and Pascoag Municipal.
- The station consists of one 115 kV to 13.8 kV load tap changing transformer with a delta/wye winding configuration, 30 degree lagging. 28,000/37,333/46,667 kVA OA/FA/FA @ 65 deg C rise
- The switchgear feeds four 13.8 kV grounded wye distribution feeders: 127W40, 127W41, 127W42, and 127W43.

(b)

- On Tuesday August 23, 2022, at 18:23, the Nasonville Substation transformer tripped off by transformer differential relaying. Operations of the equipment at the Nasonville Substation resulted in loss of all Nasonville Substation feeders and triggered alarms to Rhode Island Energy Distribution Dispatch in Lincoln, RI. A Rhode Island Energy Substation Supervisor arrived at the station shortly thereafter. There was fire burning inside the station switchgear with thick smoke. The Rhode Island Energy Overhead Line ("OHL") Department isolated the feeders from the switchgear. After confirming the isolation, the firefighters were allowed to enter the switchgear and put out the smoldering fire with portable chemical fire extinguishers. During this time, additional Rhode Island Energy Engineering and Operations personnel responded to the station. Customers were picked up on feeder ties.

- At the time, there was a severe thunderstorm with torrential downpours and lightning, which dumped several inches of rain on Southern New England. The temperature was approximately 74 degrees F with 17 mph wind gusts.

- The protective relaying operations at the Nasonville Substation were preceded by a feeder fault on the 41 feeder caused by a fallen tree between poles 253 and 254 Clear River Road (Pascoag ROW). A pole mounted recloser located on the 41 feeder between the fallen tree and the station cleared the feeder fault. Shortly after this feeder fault, there was a dielectric failure in the Nasonville switchgear in the 41 feeder cubicle. It is likely that the thru-fault from the fallen tree damaged the connection of the 41 breaker C phase terminal to the switchgear bus. This damaged connection resulted in sustained arcing

Division 1-31, page 3

with extreme heat, destroying isolation and insulation systems, causing the faulting of the switchgear bus.

(c)

Circuit	Loading at Time of Failure	Normal Rating	Emergency Rating
Nasonville 271 TR	25 MVA	51.3 MVA	57.8 MVA
127W43	325 A	559 A	597 A
127W42	225 A	495 A	495 A
127W41	150 A	495 A	495 A
127W40	175 A	495 A	495 A
Woonsocket 1 TR	15 MVA	52 MVA	60 MVA
26W7	175 A	515 A	515 A
26W5	200 A	515 A	515 A
26W1	125 A	515 A	d

(d) Approximately 4,617 Rhode Island Energy customers (kWh meters) and 4,700 Pascoag Utility District customers (kWh meters).

(e) Power restoration was a multi-step effort that was completed over several days.

- Step 1 included immediate action by the Rhode Island Energy Distribution Dispatch in Lincoln, RI using existing feeder ties to pick up load as soon as possible.
- Step 2 included the use of existing distributed generation, inclusive of solar, battery energy storage, and both existing and roll-on diesel generation to support system load during constraint periods over the multi-day effort.
- Step 3 included the installation of the mobile switchgear and restoration of all feeders to normal configuration.

Division 1-31, page 4

Step 1

8/23/202

18:23 4,617 Rhode Island Energy customers and 4,700 Pascoag Utility District customers out at beginning of event. 127W40, 127W41, 127W42, & 127W43 Feeders all out

19:03 2,623 Rhode Island Energy customers out, 1,994 customers restored using OHL crews via field ties (2/3 of 127W40 feeder restored)

19:30 1,684 Rhode Island Energy customers out, 939 additional customers restored using OHL crews via field ties (remaining 127W40 feeder)

19:44 661 Rhode Island Energy customers out, 1,023 additional customers restored using OHL crews via field ties (127W42 restored)

20:31 658 Rhode Island Energy customers out, 3 additional customers restored, Pascoag Utility District customers restored, using OHL crews via field ties (127W43 restored)

21:35 19 Rhode Island Energy customers out, 639 additional customers restored using OHL crews via field ties (most of 127W41 restored)

**At this time waiting on loads to decrease and crews to investigate a possible recloser issue to pick up remaining customers.

22:25 Tree branch in R/W on the 127W41 wire causes a fault which results in a phase burning down on Providence Pike. Due to previous restore 26W5 CB locks out, which causes 5,404 customers to lose power (most of 127W40, most of 127W41, all of 127W42 and 50% of normal 26W5 customers). This is the second outage of the event to 4,108 customers, first outage of event to 1,315 customers.

23:01 Phase Down issue isolated, 70 customers restored via remote switching, 5,334 remaining out (Original 26W5 customers)

08/24/2022

00:37 Further repairs made to Providence Pike, OHL crews keep Nasonville load isolated and restore 1,245 customers via OHL field switching (all original 26W5 customers now restored)

00:52 Further patrol completed with no issues found, OHL crews completed switching to restore 473 customers. 3,616 customers still out. (Portion of 127W40 restored)

01:13 Further patrol completed with no issues found, 1,015 customers restored via remote SCADA switching 2,601 customers still out (Portion of 127W40)

01:26 Tree in R/W issue cleared, remaining R/W patrol completed with no other issues found. All customers restored via remote SCADA switching.

Step 2 (8/24/2022 – 8/27/2022)

- Continuous monitoring of third party owned solar generating sites. This effort was primarily reactive to adjust for loss of solar due to cloud coverage.
- Continuous coordination with Pascoag Municipal, optimizing use and dispatch of their battery energy storage system and rotating generation.
- 3 Megawatts of roll-on generation was installed at the Harrisville Fire District Water Department Site (115 Central St., Burrillville, RI). The equipment was on site on 8/25/2022 at 15:30 and picked up load at 20:05.
- 3 Megawatts of generation was installed along the ROW, adjacent to the Burrillville Wastewater Treatment Plant (151 Clear River Dr., Burrillville, RI). The equipment was on site on 8/25/2022 at 20:00 and picked up load on 8/26/2022 at 14:40.
- 3 Megawatts of generation was installed along the ROW near the Burrillville Police Station (1477 Victory Highway, Oakland, RI). The equipment was on site on 8/26/2022 at 12:30 and picked up load at 18:00.

Step 3 (8/24/2022 – 9/6/2022)

- A mobile switchgear and mobile battery were delivered to Nasonville on Wednesday morning, 8/24/2022. Feeder cables were removed from the existing switchgear and extended to the mobile switchgear. Primary supply and control cables were installed from the transformer to the mobile switchgear. A temporary AC service was installed. Low voltage supply and control cables were installed from the mobile battery to the mobile switchgear. The substation transformer was tested and confirmed to be acceptable for service. On Saturday, August 27th, the mobile switchgear was energized and the Nasonville feeders were restored to normal configurations by 7:00 pm. On September 6, 2022, a remote terminal unit and cellular antenna was installed for SCADA indication and control.

(f) Please refer to Attachment DIV 1-31-1, which reflects:.

- Page 1:Portions of the Woonsocket Sub. 26W1 feeder were transferred to the Woonsocket Sub. 26W7 feeder.

- Page 2:Portions of the Woonsocket Sub. 26W5 feeder were transferred to the Riverside Sub. 108W53 and the Riverside Sub. 108W61 feeder.
- Page 3:All of the Nasonville 127W43 feeder including Pascoag Muni was transferred to the Woonsocket 26W1 feeder.
- Page 4:All of the Nasonville 127W42 feeder was transferred to the Woonsocket 26W5 feeder.
- Page 5:Portions of the Nasonville 127W41 feeder were transferred to the Woonsocket 26W5 (RI Energy customers) and the 26W1 (Pascoag Muni).
- Page 6:Portions of the Nasonville 127W40 feeder transferred to the Woonsocket 26W5 feeder, 321W2 feeder, and the 26W7 feeder.

(g)

- All durations pertinent to this restoration were provided in section E of this response:
- 100% of the load served by Nasonville had been transferred to the mobile switchgear as of Saturday August 27th at 19:00.

(h) Please refer to Attachment DIV 1-31-2, which shows:

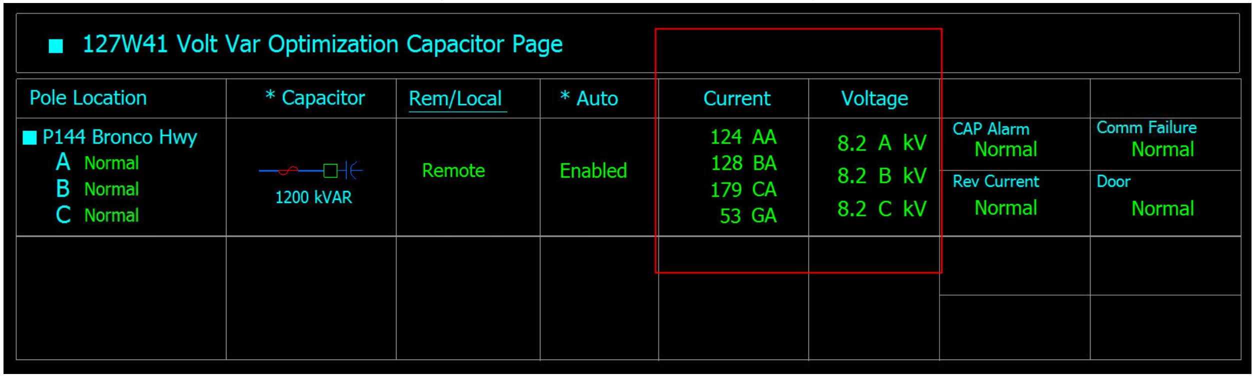
- 26W7 Feeder: Recloser 642001, P6-90 Cap Bank, P8 Graham Drive Feeder Monitor, Recloser 642118, recloser 642094, P16 capacitor bank, recloser 642117, recloser 642086, P 18 capacitor bank, Recloser 642085, Recloser 642109, recloser 642112, P26 capacitor bank
- 26W1 Feeder: Recloser 642098, Pole 194 Pascoag ROW Feeder Monitor, Recloser 642006, Recloser 642086, capacitor bank 642003, Recloser 642079, P132 Providence Pike capacitor bank, Recloser 642099
- 26W5 Feeder: Recloser 642027, capacitor bank P33 St. Paul St., Recloser 642082, P511 Great Rd., capacitor bank
- 127W43 Feeder: P391 Pascoag ROW capacitor bank, Recloser 641066, Recloser 127W43
- 127W42 Feeder: Recloser 641049, Recloser 641047
- 127W41 Feeder: P144 Bronco Highway capacitor bank, recloser 641026, recloser 641064, recloser 127W41
- 127W40 feeder: recloser 641056, P226 Douglas Pike capacitor bank, P294 Douglas Pike capacitor bank, recloser 641012, recloser 641008, recloser 642135, recloser 641063

(i)

- Pascoag Municipal was called on to deploy their 1 MW of generation and 9 MWHrs of energy storage equipment.
- Eleanor Slater Hospital, Zambarano was called upon to deploy 750 kW of emergency backup generation.
- Solar generation sites are not typically designed to be dispatched. The sites generate when the sunlight and utility connection is supportive.
- Typically, solar generation sites of 1 MW or greater connect to the distribution system through reclosers equipped with radio communications. Real time data for generation sites of less than 1 MW are typically not available to Rhode Island Energy Distribution Dispatch.
- DG sites greater than 1 MWs: Please refer to Attachment DIV 1-31-2:
    - 1 MW PV RI 16721813, Brandywick LLC, 90 Tifft Rd.: 26W7 Feeder
    - 1 MW PV, P24-33 Tifft Rd., 26W7 Feeder
    - 6.22 MW PV, RI 26549231, King Solar, 20 Oxford Rd., 26W7 Feeder
    - 2 MW PV, RI 24201390, 19733795, North Smithfield Solar, 1 Pound Hill Rd., 26W1 Feeder
    - 6.22 MW PV, RI 24845370, Turning Point Energy, P117-3 Pound Hill Rd. 26W1 Feeder
    - 0.84 MW PV, RI 25255833, Greenville Rd. Solar, P62-4 Greenville Rd., 26W1 Feeder
    - 1.6 MW Hydro, RI 138, Ridgewood Power, P37-24 ROW off St. Paul St., 26W5 Feeder
    - 2.54 MW PV, RI 23918636, Nautilus Solar, P302-3 Victory Highway, 127W42 Feeder
    - 3.3 MW PV, RI 2399135, 0 Danielle Drive, Burrillville Solar, 127W42 Feeder
    - 3.9 MW PV, FI 29106677, 0 Log Rd., Log Rd. Solar, 127W40 Feeder
    - 1 MW Generation, Pascoag Municipal, 127W41, 127W43 Feeders

The following figures show examples of capacitor and recloser information obtained through telemetry to determine the DG output in real-time.

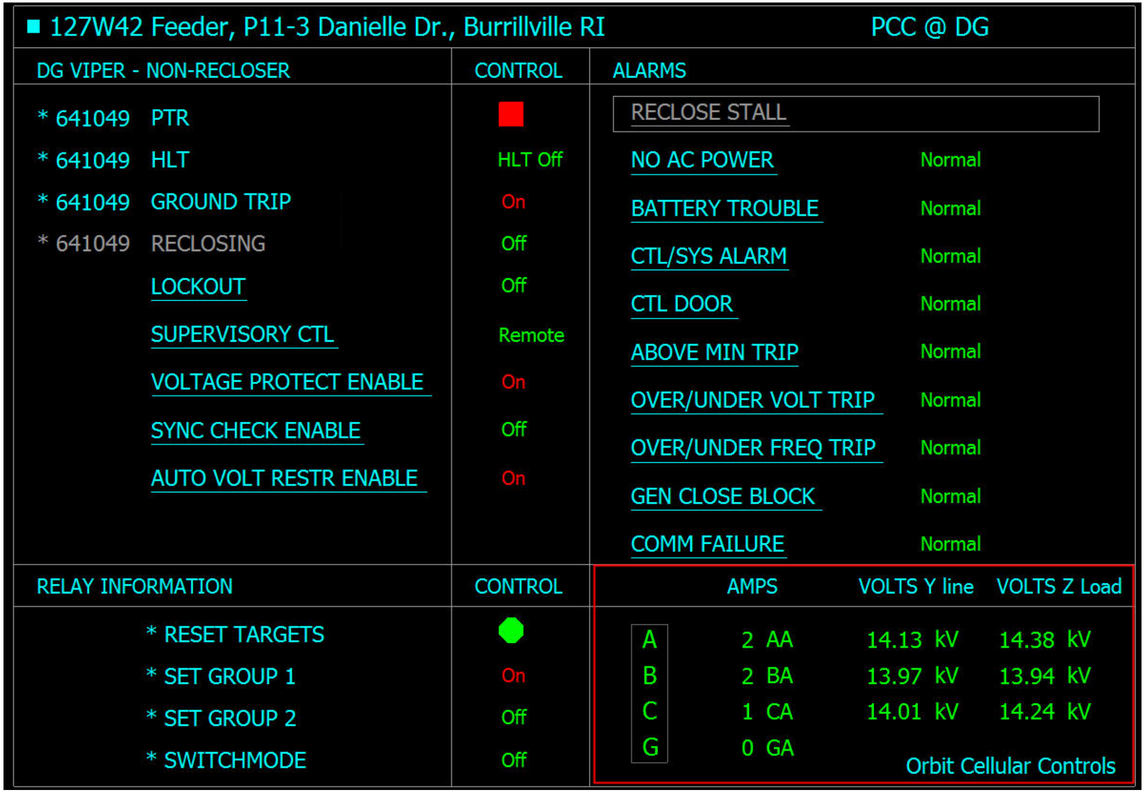
Figure DIV 1-31-1 – Typical Capacitor Information Screen
(red box shows real-time data)



■ 127W41 Volt Var Optimization Capacitor Page

Pole Location	* Capacitor	Rem/Local	* Auto	Current	Voltage		
■ P144 Bronco Hwy A Normal B Normal C Normal	1200 kVAR	Remote	Enabled	124 AA 128 BA 179 CA 53 GA	8.2 A kV 8.2 B kV 8.2 C kV	CAP Alarm Normal Rev Current Normal	Comm Failure Normal Door Normal

Figure DIV 1-31-2 – Typical Recloser Information Screen
(red box shows real-time data)



■ 127W42 Feeder, P11-3 Danielle Dr., Burrillville RI PCC @ DG

DG VIPER - NON-RECLOSER	CONTROL
* 641049 PTR	🟥
* 641049 HLT	HLT Off
* 641049 GROUND TRIP	On
* 641049 RECLOSING	Off
LOCKOUT	Off
SUPERVISORY CTL	Remote
VOLTAGE PROTECT ENABLE	On
SYNC CHECK ENABLE	Off
AUTO VOLT RESTR ENABLE	On

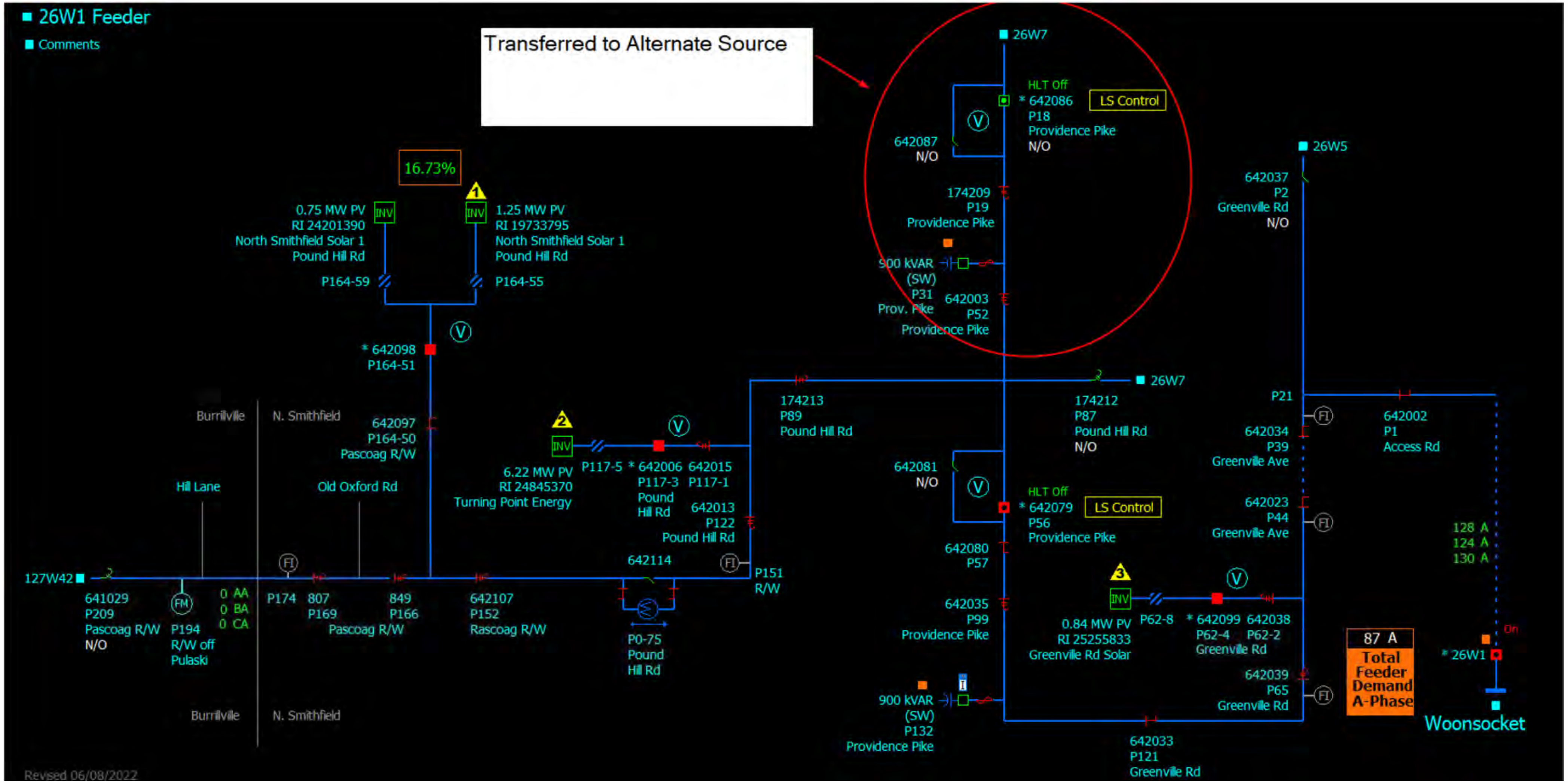
ALARMS	
RECLOSE STALL	
NO AC POWER	Normal
BATTERY TROUBLE	Normal
CTL/SYS ALARM	Normal
CTL DOOR	Normal
ABOVE MIN TRIP	Normal
OVER/UNDER VOLT TRIP	Normal
OVER/UNDER FREQ TRIP	Normal
GEN CLOSE BLOCK	Normal
COMM FAILURE	Normal

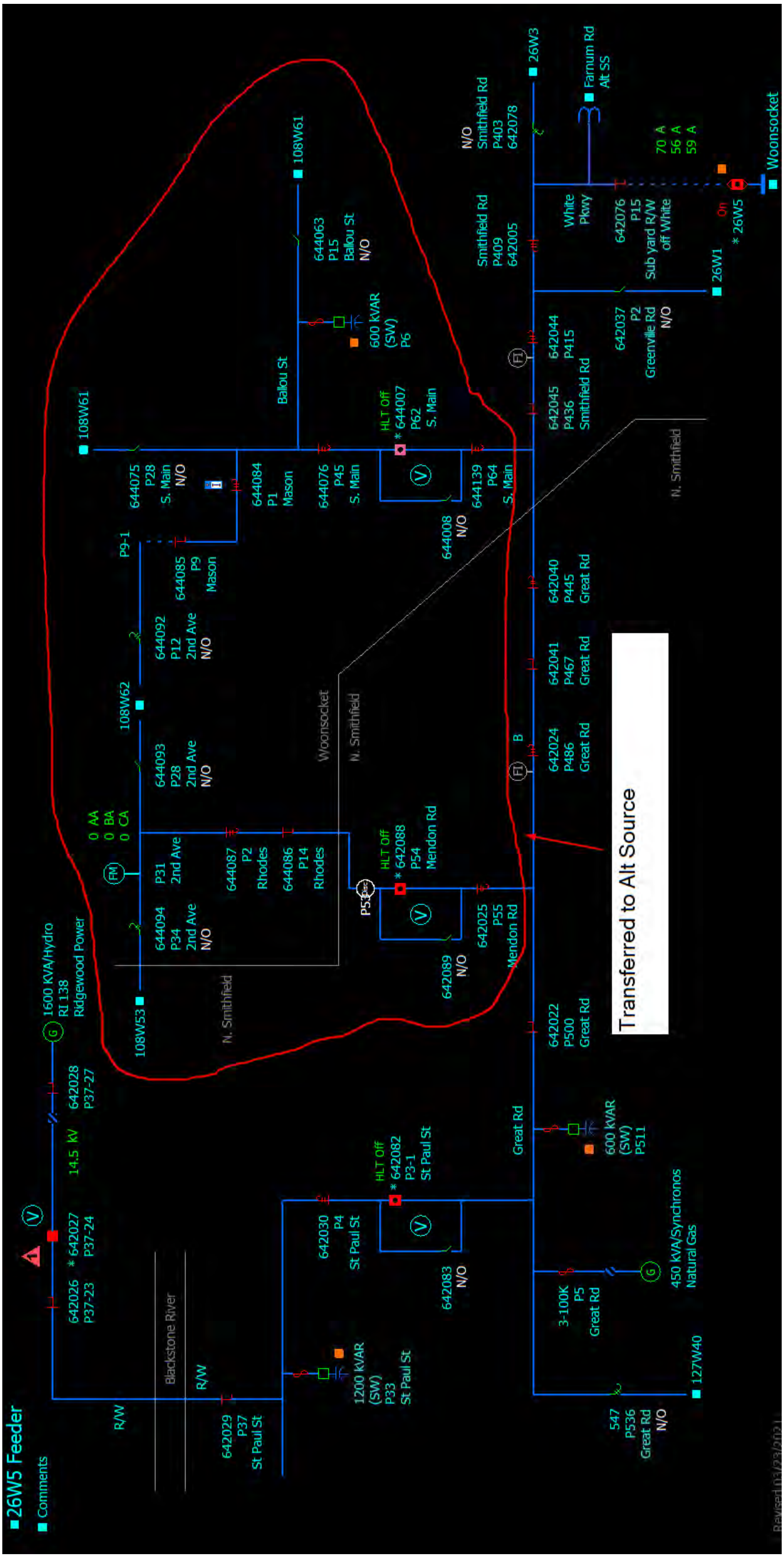
RELAY INFORMATION	CONTROL
* RESET TARGETS	●
* SET GROUP 1	On
* SET GROUP 2	Off
* SWITCHMODE	Off

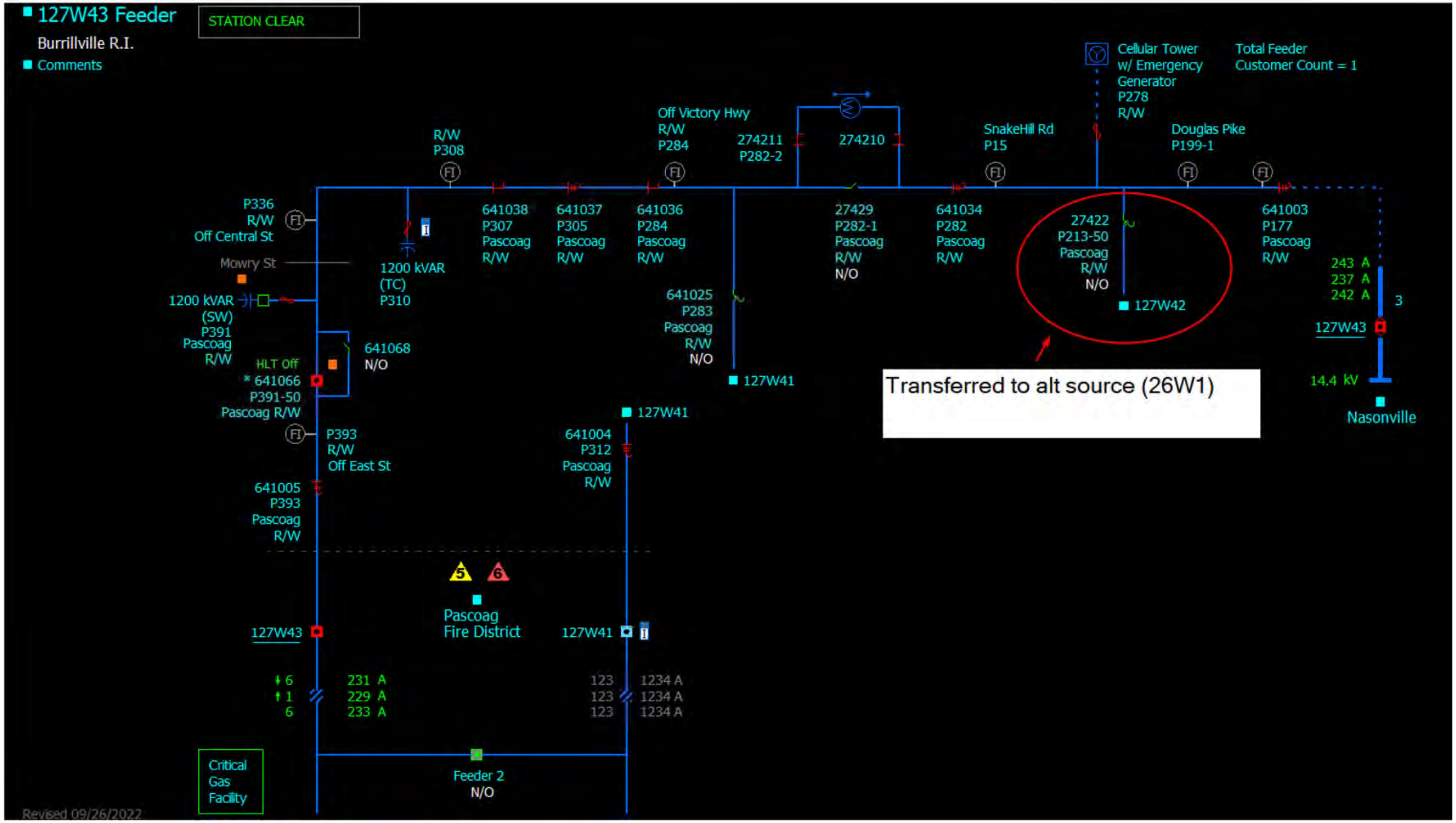
	AMPS	VOLTS Y line	VOLTS Z Load
A	2 AA	14.13 kV	14.38 kV
B	2 BA	13.97 kV	13.94 kV
C	1 CA	14.01 kV	14.24 kV
G	0 GA		

Orbit Cellular Controls

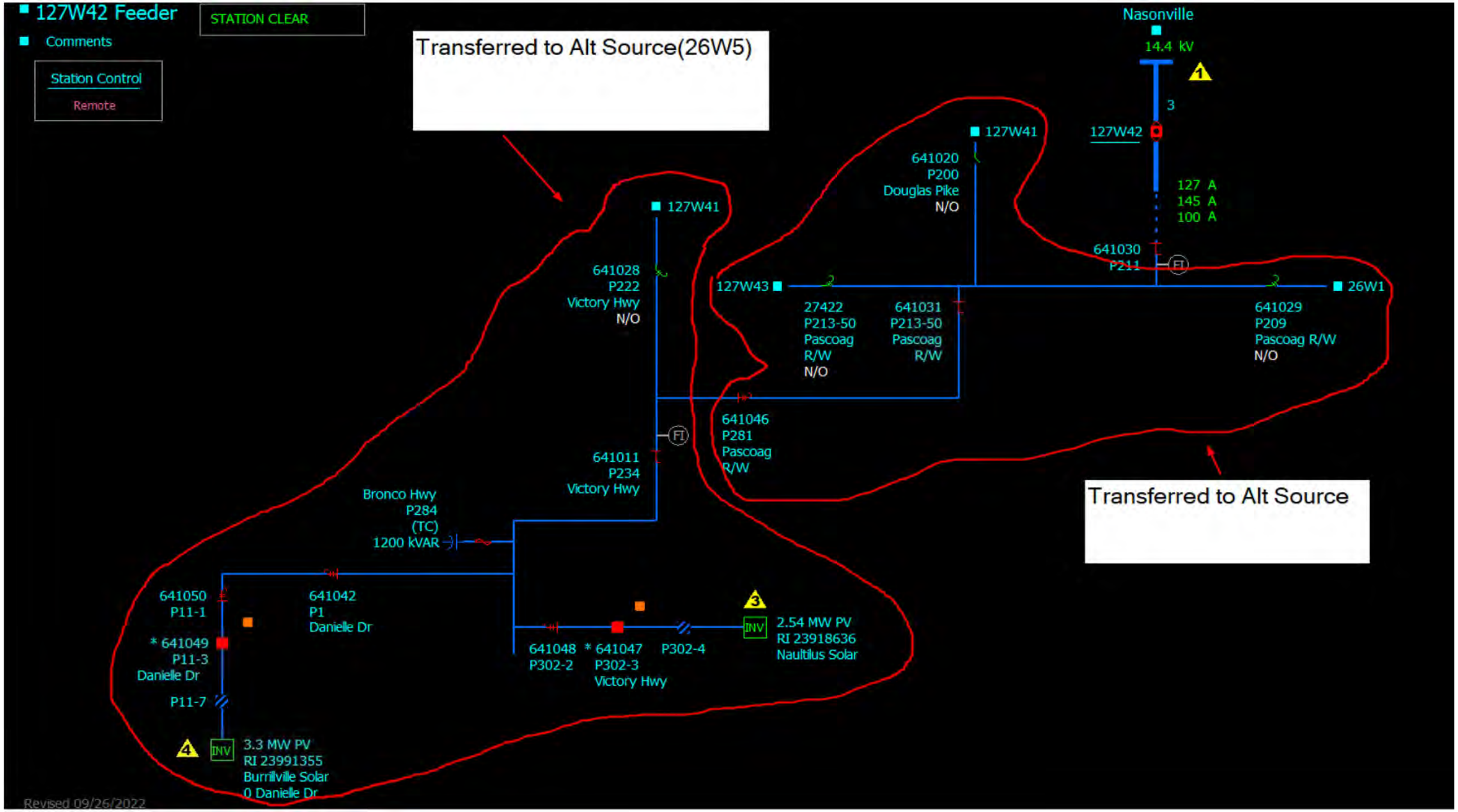
Prepared by or under the supervision of: Ryan Constable

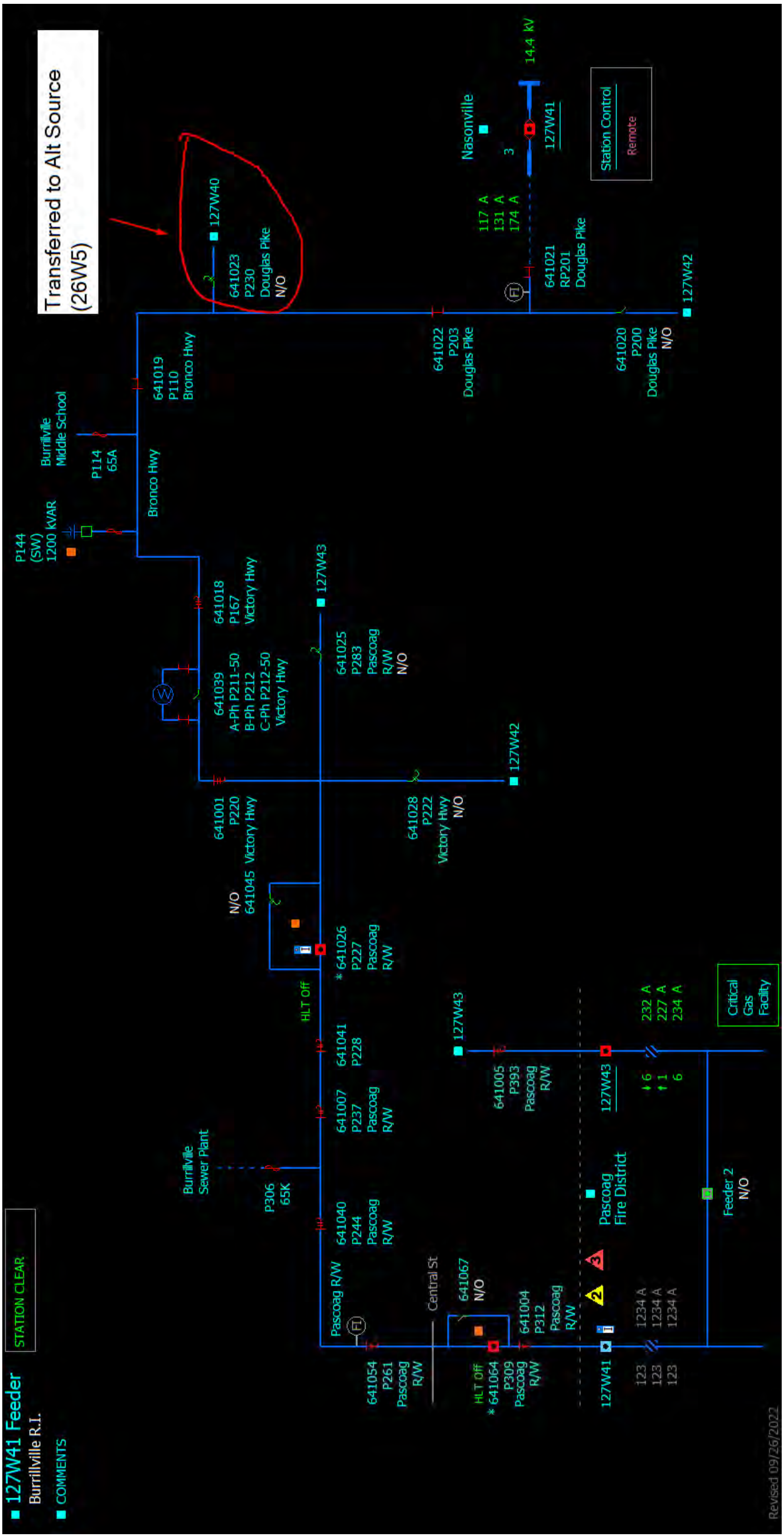

26W1 Feeder
Comments
Transferred to Alternate Source
26W7
HLT Off
* 642086
P18
Providence Pike
N/O
LS Control
642087
N/O
174209
P19
Providence Pike
900 kVAR
(SW)
P31
Prov. Pike
642003
P52
Providence Pike
26W5
642037
P2
Greenville Rd
N/O
16.73%
0.75 MW PV
RI 24201390
North Smithfield Solar 1
Pound Hill Rd
1.25 MW PV
RI 19733795
North Smithfield Solar 1
Pound Hill Rd
INV
1
P164-59
P164-55
* 642098
P164-51
26W7
174213
P89
Pound Hill Rd
174212
P87
Pound Hill Rd
N/O
P21
642002
P1
Access Rd
Burrillville
N. Smithfield
642097
P164-50
Pascoag R/W
2
6.22 MW PV
RI 24845370
Turning Point Energy
P117-5
* 642006
P117-3
Pound
Hill Rd
642015
P117-1
642013
P122
Pound Hill Rd
642081
N/O
HLT Off
* 642079
P56
Providence Pike
LS Control
642034
P39
Greenville Ave
642023
P44
Greenville Ave
Hill Lane
Old Oxford Rd
128 A
124 A
130 A
127W42
641029
P209
Pascoag R/W
N/O
FM
P194
R/W off
Pulaski
0 AA
0 BA
0 CA
FI
P174
807
P169
849
P166
Pascoag R/W
642107
P152
Rascoag R/W
642114
P0-75
Pound
Hill Rd
P151
R/W
642080
P57
642035
P99
Providence Pike
3
0.84 MW PV
RI 25255833
Greenville Rd Solar
P62-8
* 642099
P62-4
642038
P62-2
Greenville Rd
642039
P65
Greenville Rd
87 A
Total
Feeder
Demand
A-Phase
On
* 26W1
Woonsocket
900 kVAR
(SW)
P132
Providence Pike
642033
P121
Greenville Rd
Burrillville
N. Smithfield
Revised 06/08/2022

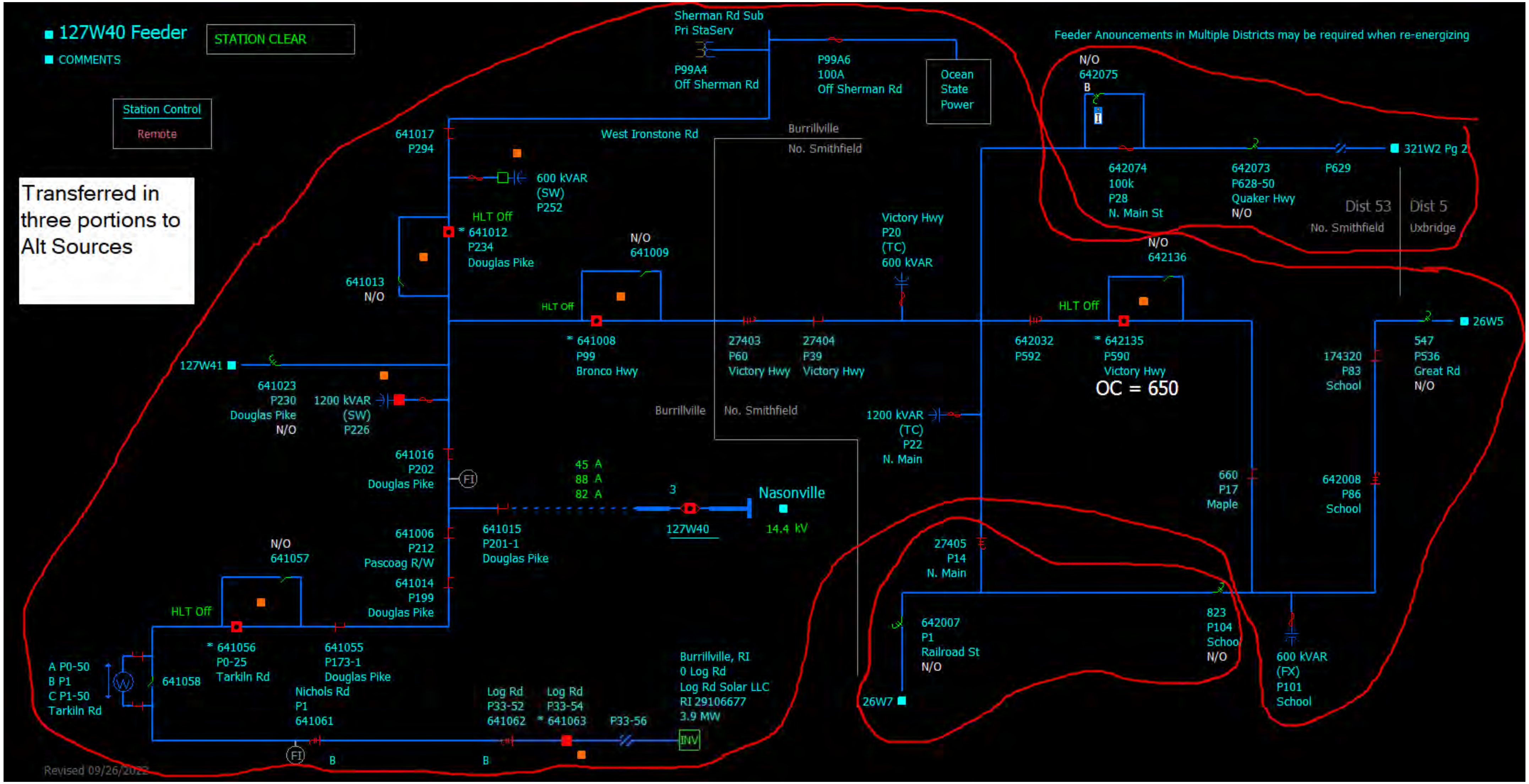

26W5 Feeder
Comments
642026 P37-23
* 642027 P37-24
14.5 kV
642028 P37-27
1600 KVA/Hydro RI 138 Ridgewood Power
R/W
Blackstone River
R/W
642029 P37 St Paul St
1200 kVAR (SW) P33 St Paul St
642030 P4 St Paul St
HLT Off * 642082 P3-1 St Paul St
642083 N/O
108W53
644094 P34 2nd Ave N/O
P31 2nd Ave
0 AA 0 BA 0 CA
644093 P28 2nd Ave N/O
108W62
644092 P12 2nd Ave N/O
P9-1
644085 P9 Mason
644075 P28 S. Main N/O
108W61
644087 P2 Rhodes
644086 P14 Rhodes
N. Smithfield
Woonsocket
N. Smithfield
644084 P1 Mason
Ballou St
644063 P15 Ballou St N/O
108W61
644076 P45 S. Main
600 kVAR (SW) P6
HLT Off * 644007 P62 S. Main
644008 N/O
644139 P64 S. Main
P53
HLT Off * 642088 P54 Mendon Rd
642089 N/O
642025 P55 Mendon Rd
B
Great Rd
642022 P500 Great Rd
642024 P486 Great Rd
642041 P467 Great Rd
642040 P445 Great Rd
642045 P436 Smithfield Rd
642044 P415
Smithfield Rd P409 642005
N/O Smithfield Rd P403 642078
26W3
Farnum Rd Alt SS
White Pkwy
642076 P15 Sub yard R/W off White
70 A 56 A 59 A
642037 P2 Greenville Rd N/O
26W1
On * 26W5
Woonsocket
N. Smithfield
Transferred to Alt Source
600 kVAR (SW) P511
3-100K P5 Great Rd
450 kVA/Synchronos Natural Gas
547 P536 Great Rd N/O
127W40
Revised 03/23/2021

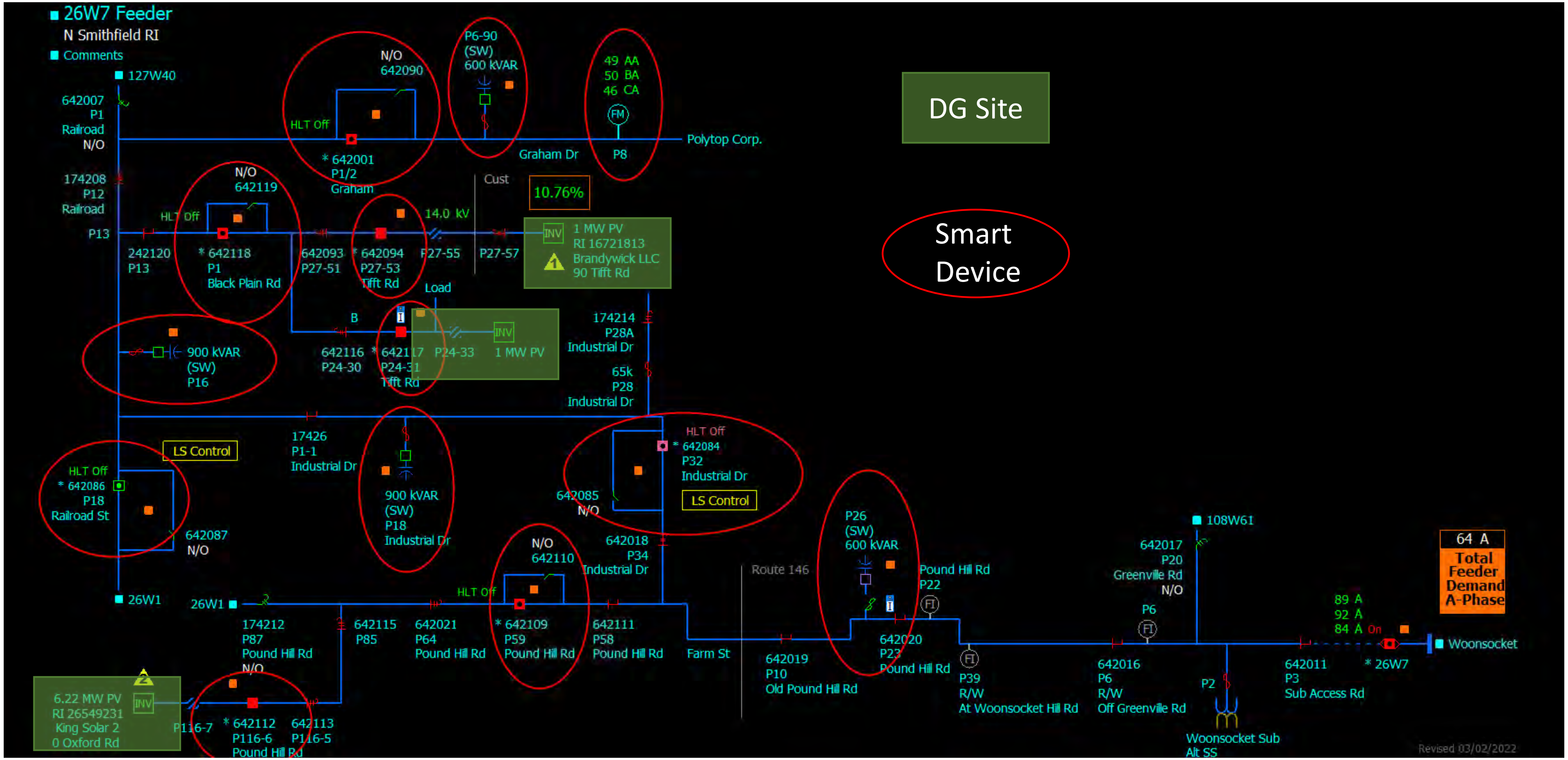


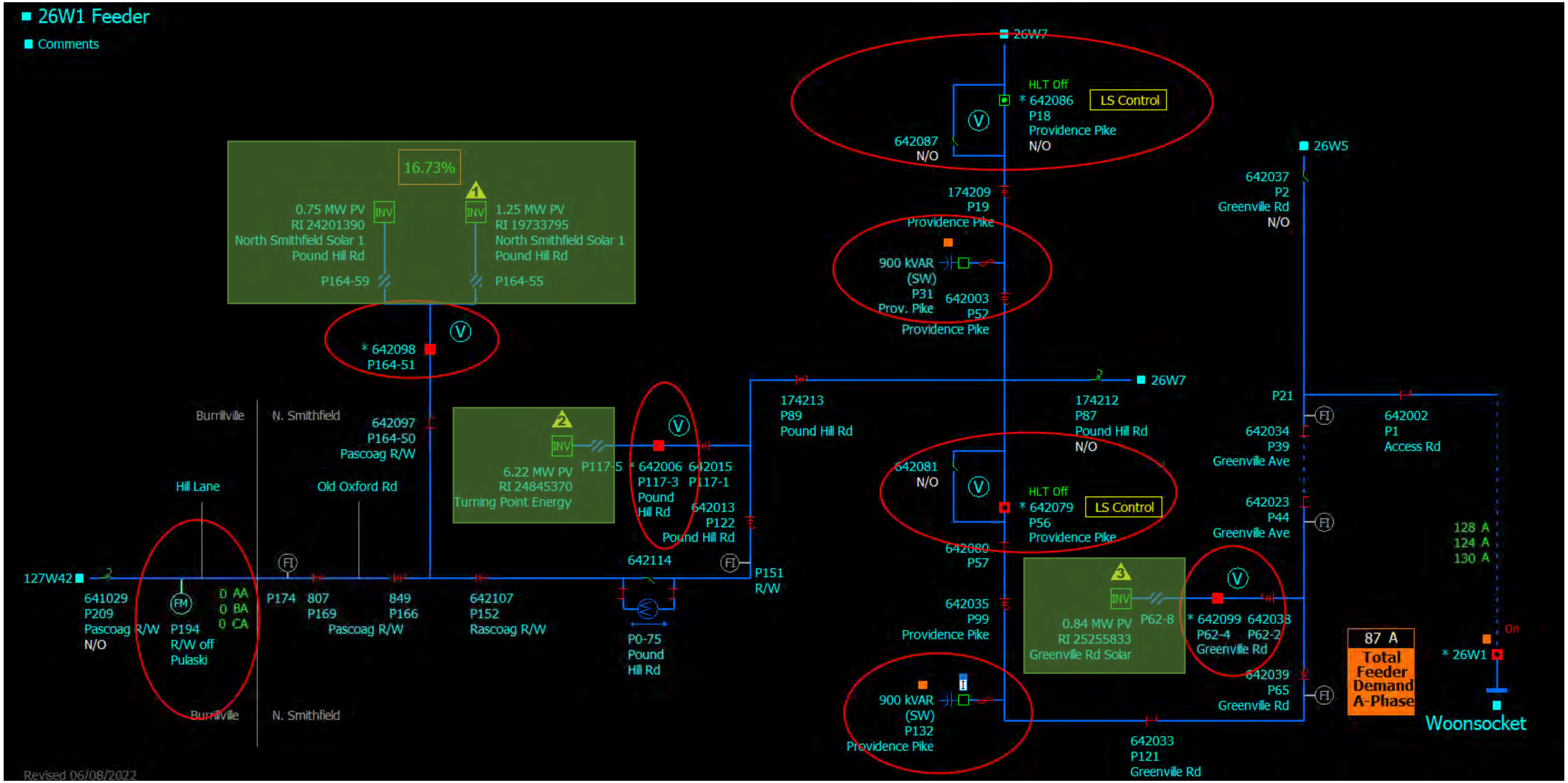
Transferred to alt source (26W1)

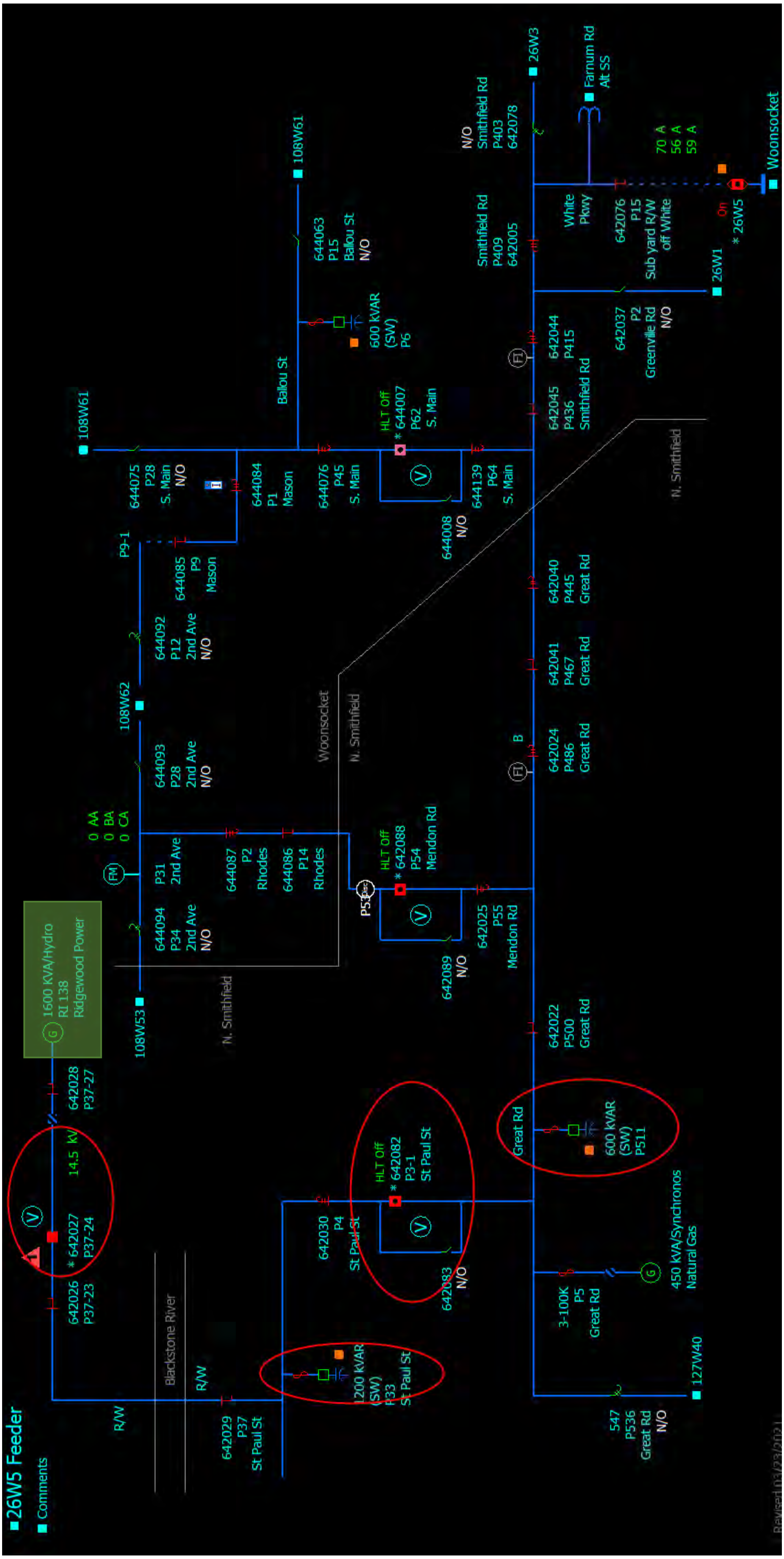

127W42 Feeder
Comments
STATION CLEAR
Station Control
Remote
Transferred to Alt Source(26W5)
Transferred to Alt Source
Nasonville
14.4 kV
1
3
127W42
127 A
145 A
100 A
641030
P211
FI
127W41
641020
P200
Douglas Pike
N/O
127W43
27422
P213-50
Pascoag
R/W
N/O
641031
P213-50
Pascoag
R/W
26W1
641029
P209
Pascoag R/W
N/O
127W41
641028
P222
Victory Hwy
N/O
641046
P281
Pascoag
R/W
FI
641011
P234
Victory Hwy
Bronco Hwy
P284
(TC)
1200 kVAR
641042
P1
Danielle Dr
641050
P11-1
* 641049
P11-3
Danielle Dr
P11-7
4
INV
3.3 MW PV
RI 23991355
Burrillville Solar
0 Danielle Dr
641048
P302-2
* 641047
P302-3
Victory Hwy
P302-4
3
INV
2.54 MW PV
RI 23918636
Naultilus Solar
Revised 09/26/2022

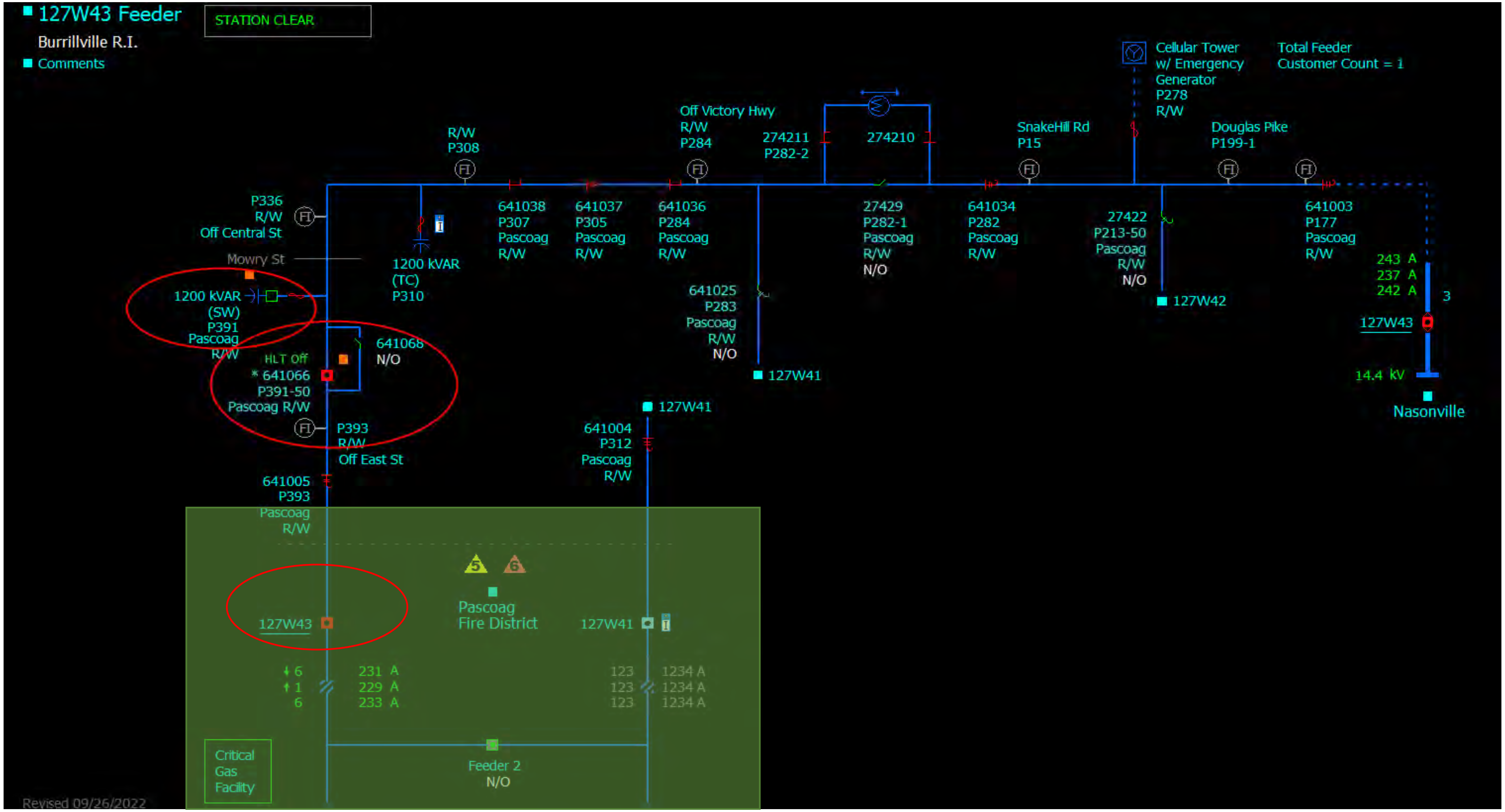

127W41 Feeder
Burrillville R.I.
COMMENTS
STATION CLEAR
Transferred to Alt Source (26W5)
127W40
641023
P230
Douglas Pike
N/O
Nasonville
14.4 kV
127W41
3
117 A
131 A
174 A
Station Control
Remote
641021
RP201
Douglas Pike
127W42
641020
P200
Douglas Pike
N/O
641022
P203
Douglas Pike
641019
P110
Bronco Hwy
Bronco Hwy
Burrillville Middle School
P114
65A
P144
(SW)
1200 kVAR
641018
P167
Victory Hwy
127W43
641025
P283
Pascoag
R/W
N/O
641039
A-Ph P211-50
B-Ph P212
C-Ph P212-50
Victory Hwy
127W42
641001
P220
Victory Hwy
641028
P222
Victory Hwy
N/O
N/O
641045
HLT Off
* 641026
P227
Pascoag
R/W
641041
P228
127W43
641005
P393
Pascoag
R/W
127W43
6
1
6
232 A
227 A
234 A
Critical Gas Facility
Burrillville Sewer Plant
P306
65K
641007
P237
Pascoag
R/W
Pascoag Fire District
Feeder 2
N/O
641040
P244
Pascoag
R/W
Pascoag R/W
Central St
641067
N/O
3
2
641004
P312
Pascoag
R/W
641054
P261
Pascoag
R/W
HLT Off
* 641064
P309
Pascoag
R/W
127W41
1234 A
1234 A
1234 A
123
123
123
Revised 09/26/2022

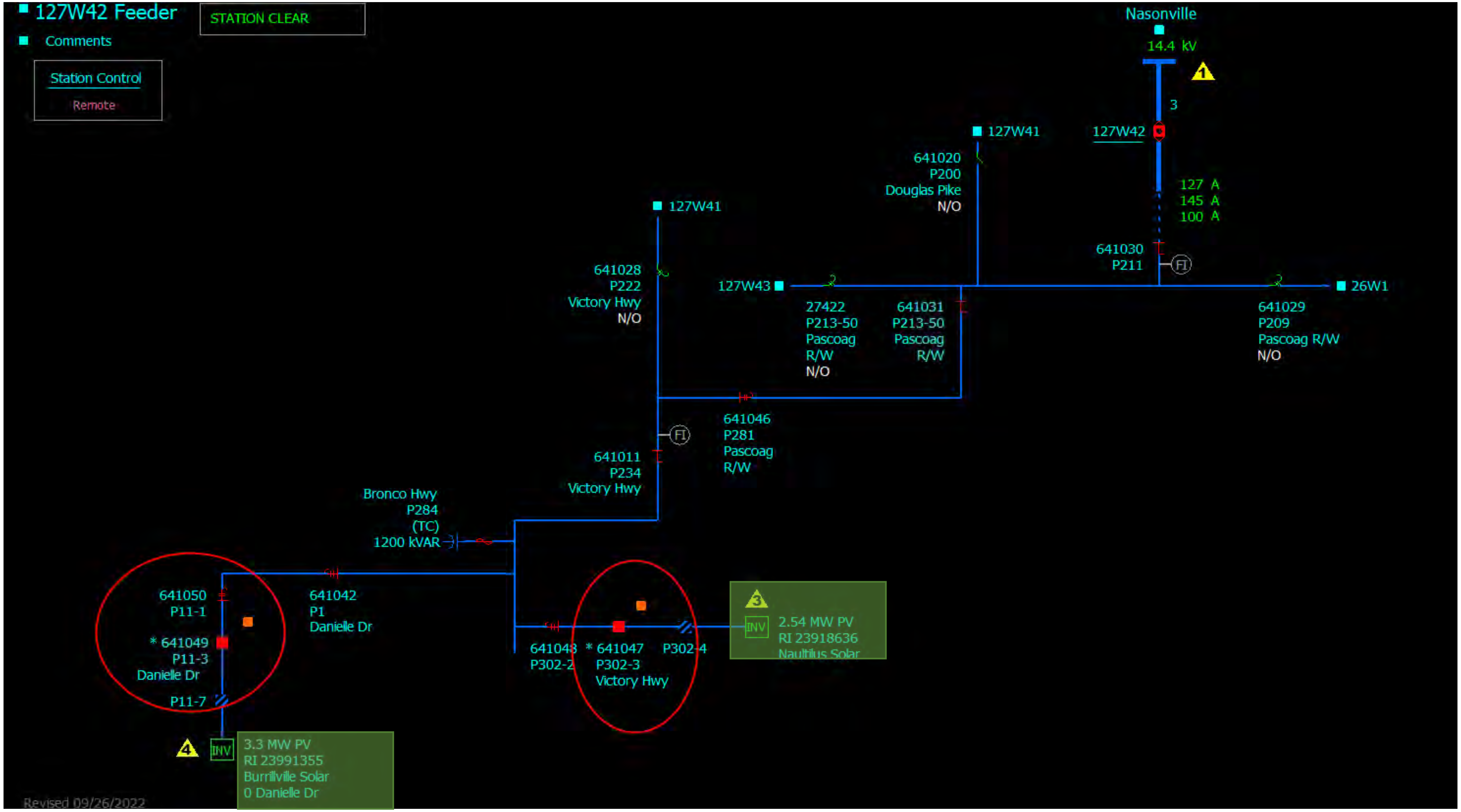

127W40 Feeder
COMMENTS
STATION CLEAR
Station Control
Remote
Transferred in three portions to Alt Sources
Sherman Rd Sub Pri StaServ
P99A4 Off Sherman Rd
P99A6 100A Off Sherman Rd
Ocean State Power
Feeder Anouncements in Multiple Districts may be required when re-energizing
N/O 642075 B
642074 100k P28 N. Main St
642073 P628-50 Quaker Hwy N/O
P629
321W2 Pg 2
Dist 53 No. Smithfield
Dist 5 Uxbridge
N/O 642136
641017 P294
West Ironstone Rd
Burrillville
No. Smithfield
600 kVAR (SW) P252
HLT Off
* 641012 P234 Douglas Pike
641013 N/O
N/O 641009
HLT Off
* 641008 P99 Bronco Hwy
27403 P60 Victory Hwy
27404 P39 Victory Hwy
Victory Hwy P20 (TC) 600 kVAR
HLT Off
642032 P592
* 642135 P590 Victory Hwy
OC = 650
174320 P83 School
547 P536 Great Rd N/O
26W5
127W41
641023 P230 Douglas Pike N/O
1200 kVAR (SW) P226
Burrillville
No. Smithfield
1200 kVAR (TC) P22 N. Main
641016 P202 Douglas Pike
FI
45 A
88 A
82 A
3
Nasonville
127W40
14.4 kV
660 P17 Maple
642008 P86 School
641006 P212 Pascoag R/W
641015 P201-1 Douglas Pike
27405 P14 N. Main
641014 P199 Douglas Pike
N/O 641057
HLT Off
642007 P1 Railroad St N/O
823 P104 School N/O
600 kVAR (FX) P101 School
A P0-50
B P1
C P1-50
Tarkiln Rd
641058
* 641056 P0-25 Tarkiln Rd
641055 P173-1 Douglas Pike
Nichols Rd P1 641061
Log Rd P33-52 641062
Log Rd P33-54 * 641063
P33-56
Burrillville, RI 0 Log Rd Log Rd Solar LLC RI 29106677 3.9 MW
INV
26W7
FI
B
B
Revised 09/26/2022

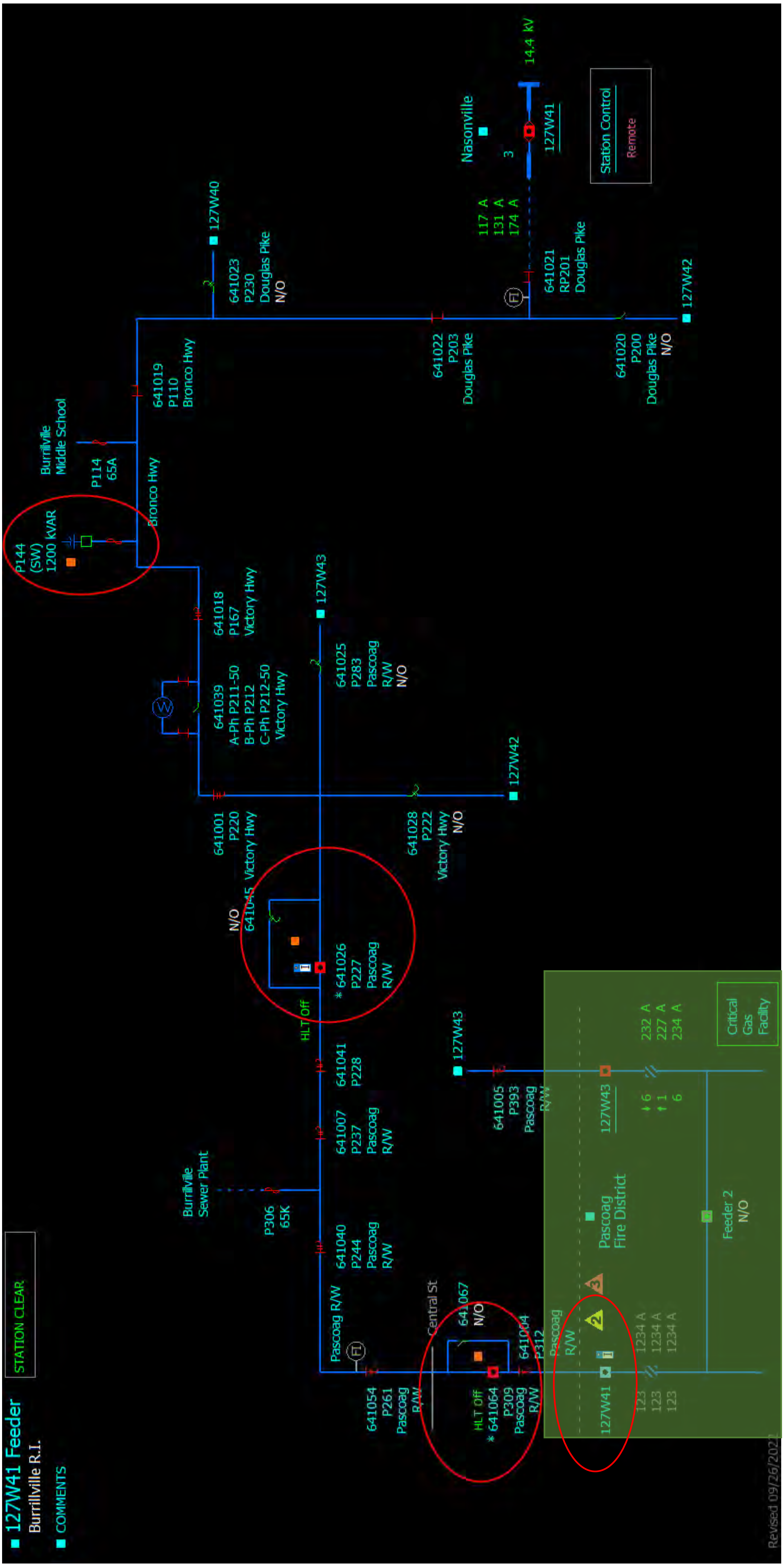

26W7 Feeder
N Smithfield RI
Comments
127W40
642007 P1 Railroad N/O
174208 P12 Railroad
P13
242120 P13
HLT Off
N/O 642119
* 642118 P1 Black Plain Rd
N/O 642090
HLT Off
* 642001 P1/2 Graham
P6-90 (SW) 600 kVAR
Graham Dr
49 AA
50 BA
46 CA
FM
P8
Polytop Corp.
DG Site
Smart Device
Cust
10.76%
14.0 kV
642093 P27-51
* 642094 P27-53 Tifft Rd
P27-55
P27-57
Load
INV
1 MW PV RI 16721813 Brandywick LLC 90 Tifft Rd
B
642116 P24-30
* 642117 P24-31 Tifft Rd
P24-33
1 MW PV
174214 P28A Industrial Dr
65k P28 Industrial Dr
900 kVAR (SW) P16
LS Control
HLT Off
* 642086 P18 Railroad St
642087 N/O
17426 P1-1 Industrial Dr
900 kVAR (SW) P18 Industrial Dr
HLT Off
* 642084 P32 Industrial Dr
LS Control
642085 N/O
642018 P34 Industrial Dr
N/O 642110
HLT Off
* 642109 P59 Pound Hill Rd
26W1
26W1
174212 P87 Pound Hill Rd N/O
642115 P85
642021 P64 Pound Hill Rd
642111 P58 Pound Hill Rd
Farm St
Route 146
642019 P10 Old Pound Hill Rd
P26 (SW) 600 kVAR
Pound Hill Rd P22
FI
642020 P23 Pound Hill Rd
P39 R/W At Woonsocket Hill Rd
642017 P20 Greenville Rd N/O
108W61
P6
642016 P6 R/W Off Greenville Rd
P2
Woonsocket Sub Alt SS
642011 P3 Sub Access Rd
89 A
92 A
84 A On
* 26W7
Woonsocket
64 A
Total Feeder Demand A-Phase
6.22 MW PV RI 26549231 King Solar 2 0 Oxford Rd
P116-7
* 642112 P116-6 Pound Hill Rd
642113 P116-5
Revised 03/02/2022

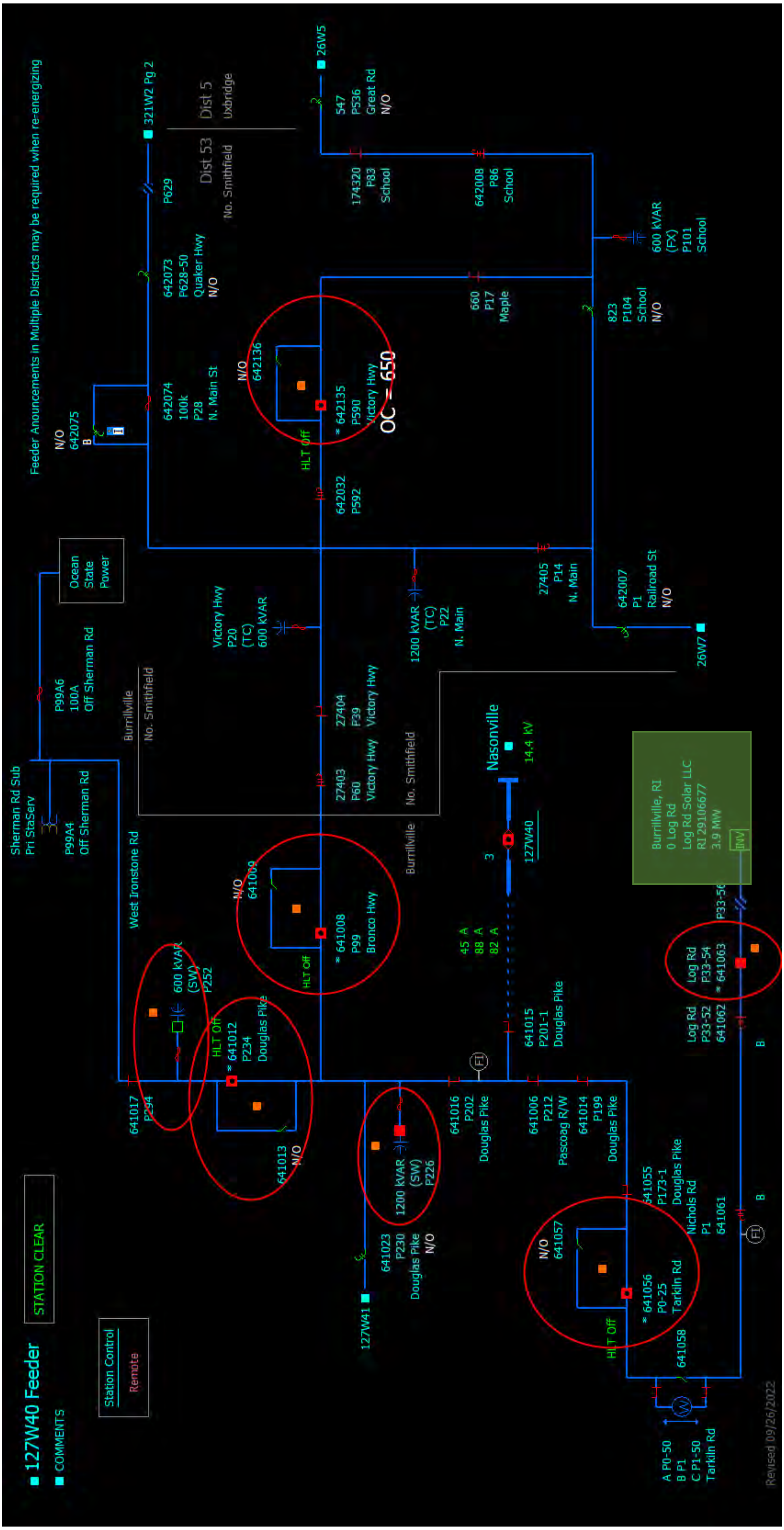

26W1 Feeder
Comments
26W7
HLT Off
* 642086
P18
Providence Pike
N/O
LS Control
642087
N/O
26W5
642037
P2
Greenville Rd
N/O
16.73%
0.75 MW PV
RI 24201390
North Smithfield Solar 1
Pound Hill Rd
P164-59
INV
1.25 MW PV
RI 19733795
North Smithfield Solar 1
Pound Hill Rd
P164-55
174209
P19
Providence Pike
900 kVAR
(SW)
P31
Prov. Pike
642003
P52
Providence Pike
* 642098
P164-51
26W7
174213
P89
Pound Hill Rd
174212
P87
Pound Hill Rd
N/O
P21
642002
P1
Access Rd
642034
P39
Greenville Ave
Burrillville
N. Smithfield
642097
P164-50
Pascoag R/W
6.22 MW PV
RI 24845370
Turning Point Energy
P117-5
* 642006
P117-3
Pound
Hill Rd
642015
P117-1
642013
P122
Pound Hill Rd
642081
N/O
HLT Off
* 642079
P56
Providence Pike
LS Control
642023
P44
Greenville Ave
Hill Lane
Old Oxford Rd
642080
P57
128 A
124 A
130 A
127W42
641029
P209
Pascoag R/W
N/O
FM
P194
R/W off
Pulaski
0 AA
0 BA
0 CA
FI
P174
807
P169
849
P166
Pascoag R/W
642107
P152
Rascoag R/W
642114
P0-75
Pound
Hill Rd
P151
R/W
642035
P99
Providence Pike
0.84 MW PV
RI 25255833
Greenville Rd Solar
P62-8
* 642099
P62-4
642033
P62-2
Greenville Rd
87 A
Total
Feeder
Demand
A-Phase
On
* 26W1
642039
P65
Greenville Rd
900 kVAR
(SW)
P132
Providence Pike
642033
P121
Greenville Rd
Woonsocket
Burrillville
N. Smithfield
Revised 06/08/2022


26W5 Feeder
Comments
1600 KVA/Hydro
RI 138
Ridgewood Power
642028
P37-27
14.5 kV
* 642027
P37-24
642026
P37-23
R/W
Blackstone River
R/W
642029
P37
St Paul St
1200 kVAR
(SW)
P33
St Paul St
642030
P4
St Paul St
HLT Off
* 642082
P3-1
St Paul St
642083
N/O
Great Rd
600 kVAR
(SW)
P511
450 kVA/Synchronos
Natural Gas
3-100K
P5
Great Rd
547
P536
Great Rd
N/O
127W40
642022
P500
Great Rd
108W53
N. Smithfield
644094
P34
2nd Ave
N/O
P31
2nd Ave
FM
0 AA
0 BA
0 CA
644087
P2
Rhodes
644086
P14
Rhodes
P53
HLT Off
* 642088
P54
Mendon Rd
642089
N/O
642025
P55
Mendon Rd
644093
P28
2nd Ave
N/O
108W62
Woonsocket
N. Smithfield
642024
P486
Great Rd
B
FI
642041
P467
Great Rd
642040
P445
Great Rd
644092
P12
2nd Ave
N/O
644085
P9
Mason
P9-1
644075
P28
S. Main
N/O
108W61
644084
P1
Mason
644076
P45
S. Main
644008
N/O
644139
P64
S. Main
HLT Off
* 644007
P62
S. Main
Ballou St
600 kVAR
(SW)
P6
644063
P15
Ballou St
N/O
108W61
N. Smithfield
642045
P436
Smithfield Rd
642044
P415
Smithfield Rd
FI
642037
P2
Greenville Rd
N/O
26W1
Smithfield Rd
P409
642005
White
Pkwy
642076
P15
Sub yard R/W
off White
On
* 26W5
N/O
Smithfield Rd
P403
642078
26W3
Farnum Rd
Alt SS
70 A
56 A
59 A
Woonsocket
Revised 03/23/2021


127W43 Feeder
STATION CLEAR
Burrillville R.I.
Comments
Cellular Tower
w/ Emergency
Generator
P278
R/W
Total Feeder
Customer Count = 1
Off Victory Hwy
R/W
P284
274211
P282-2
274210
SnakeHill Rd
P15
Douglas Pike
P199-1
R/W
P308
P336
R/W
Off Central St
Mowry St
1200 kVAR
(SW)
P391
Pascoag
R/W
1200 kVAR
(TC)
P310
641038
P307
Pascoag
R/W
641037
P305
Pascoag
R/W
641036
P284
Pascoag
R/W
27429
P282-1
Pascoag
R/W
N/O
641034
P282
Pascoag
R/W
27422
P213-50
Pascoag
R/W
N/O
641003
P177
Pascoag
R/W
243 A
237 A
242 A
3
127W43
14.4 kV
Nasonville
127W42
641025
P283
Pascoag
R/W
N/O
127W41
641068
N/O
HLT Off
* 641066
P391-50
Pascoag R/W
P393
R/W
Off East St
641005
P393
Pascoag
R/W
127W41
641004
P312
Pascoag
R/W
5
6
Pascoag
Fire District
127W43
127W41
6
1
6
231 A
229 A
233 A
123
123
123
1234 A
1234 A
1234 A
Critical
Gas
Facility
Feeder 2
N/O
Revised 09/26/2022


127W42 Feeder
STATION CLEAR
Comments
Station Control
Remote
Nasonville
14.4 kV
1
3
127W42
127 A
145 A
100 A
641030
P211
FI
127W41
641020
P200
Douglas Pike
N/O
127W41
641028
P222
Victory Hwy
N/O
127W43
27422
P213-50
Pascoag
R/W
N/O
641031
P213-50
Pascoag
R/W
26W1
641029
P209
Pascoag R/W
N/O
641046
P281
Pascoag
R/W
FI
641011
P234
Victory Hwy
Bronco Hwy
P284
(TC)
1200 kVAR
641050
P11-1
* 641049
P11-3
Danielle Dr
P11-7
641042
P1
Danielle Dr
4
INV
3.3 MW PV
RI 23991355
Burrillville Solar
0 Danielle Dr
641048
P302-2
* 641047
P302-3
Victory Hwy
P302-4
3
INV
2.54 MW PV
RI 23918636
Naultilus Solar
Revised 09/26/2022


127W41 Feeder
Burrillville R.I.
COMMENTS
STATION CLEAR
Pascoag R/W
641054
P261
Pascoag
R/W
Central St
641067
N/O
HLT Off
* 641064
P309
Pascoag
R/W
641004
P312
Pascoag
R/W
127W41
123
123
123
1234 A
1234 A
1234 A
2
3
Pascoag
Fire District
Feeder 2
N/O
641040
P244
Pascoag
R/W
P306
65K
Burrillville
Sewer Plant
641007
P237
Pascoag
R/W
641041
P228
641005
P393
Pascoag
R/W
127W43
127W43
6
1
6
232 A
227 A
234 A
Critical
Gas
Facility
HLT Off
* 641026
P227
Pascoag
R/W
N/O
641045
641001
P220
Victory Hwy
641028
P222
Victory Hwy
N/O
127W42
641039
A-Ph P211-50
B-Ph P212
C-Ph P212-50
Victory Hwy
641025
P283
Pascoag
R/W
N/O
127W43
641018
P167
Victory Hwy
P144
(SW)
1200 kVAR
Bronco Hwy
P114
65A
Burrillville
Middle School
641019
P110
Bronco Hwy
641023
P230
Douglas Pike
N/O
127W40
641022
P203
Douglas Pike
641020
P200
Douglas Pike
N/O
127W42
641021
RP201
Douglas Pike
FI
117 A
131 A
174 A
3
Nasonville
127W41
14.4 kV
Station Control
Remote
Revised 09/26/2022


127W40 Feeder
COMMENTS
STATION CLEAR
Station Control
Remote
Sherman Rd Sub
Pri StaServ
P99A4
Off Sherman Rd
P99A6
100A
Off Sherman Rd
Ocean State Power
Feeder Anouncements in Multiple Districts may be required when re-energizing
N/O
642075
B
642074
100k
P28
N. Main St
642073
P628-50
Quaker Hwy
N/O
P629
321W2 Pg 2
Dist 53
No. Smithfield
Dist 5
Uxbridge
Burrillville
No. Smithfield
West Ironstone Rd
641017
P294
600 kVAR
(SW)
P252
HLT Off
641012
P234
Douglas Pike
641013
N/O
127W41
641023
P230
Douglas Pike
N/O
1200 kVAR
(SW)
P226
N/O
641009
641008
P99
Bronco Hwy
HLT Off
27403
P60
Victory Hwy
27404
P39
Victory Hwy
Victory Hwy
P20
(TC)
600 kVAR
642032
P592
HLT Off
642135
P590
Victory Hwy
OC = 650
N/O
642136
174320
P83
School
547
P536
Great Rd
N/O
26W5
641016
P202
Douglas Pike
FI
641015
P201-1
Douglas Pike
45 A
88 A
82 A
3
127W40
Nasonville
14.4 kV
Burrillville
No. Smithfield
1200 kVAR
(TC)
P22
N. Main
660
P17
Maple
642008
P86
School
27405
P14
N. Main
642007
P1
Railroad St
N/O
26W7
823
P104
School
N/O
600 kVAR
(FX)
P101
School
641006
P212
Pascoag R/W
641014
P199
Douglas Pike
N/O
641057
HLT Off
641056
P0-25
Tarkiln Rd
641058
641055
P173-1
Douglas Pike
Nichols Rd
P1
641061
A P0-50
B P1
C P1-50
Tarkiln Rd
W
FI
B
B
Log Rd
P33-52
641062
Log Rd
P33-54
641063
P33-56
Burrillville, RI
0 Log Rd
Log Rd Solar LLC
RI 29106677
3.9 MW
INV
Revised 09/26/2022

Division 1-32

Request:

How often does the Company experience a catastrophic substation event (non-storm)? Provide a detailed list of occurrences over the last 15 years.

Response:

For purposes of this response a catastrophic substation event is defined as an event with CI >= 2000 and CMI > 25000, duration greater than 5 hours and with major equipment failure. From 01/01/2006 to 10/31/2022, on blue sky days, the Company has experienced two such events, one in 2022 and the other in 2014.

The details of the two events are shown in Attachment DIV 1-32 in executable form.

EVNT_ID	TIME_OFF	Year	CI	CMI	DURTN_TOTL (min)	Duration (hour)	SAIFI	SAIDI	CAUSE_INTRPTN_DESC	FAILD_CMPNT_DESC
8545240	8/23/2022 06:23:25 PM	2022	10019	1233194	605.38	10.09	0.02	2.46148	Lightning	Substation device other
7886965	7/7/2014 09:06:16 PM	2014	2511	322743	302.98	5.05	0.005	0.667	Device Failed	Regulator

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Division 1-33

Request:

The Company has discussed that GMP investments would be important in restoration efforts following an event similar to Nasonville. To expand on the Company's statement, describe the GMP investments, how the Company would rely on the investments, how the GMP investments would change or improve restoration efforts achieved by the Company, the quantifiable improvement in reliability that would be expected with GMP investments, and the estimated cost of the GMP investments.

Response:

The Grid Modernization Plan ("GMP") investments could have assisted the Nasonville restoration in many ways. The following list describes the issues, how the GMP investments could have mitigated the issues, and approximate quantification of the benefits. The costs of the GMP investments are not provided in this response because the GMP investments represent a comprehensive solution that cannot be broken down and attributed to a single event. The Nasonville event alone does not justify the GMP investments. Instead, the Nasonville event provides a recent case of how the GMP investments provide a number of benefits and provide those benefits immediately.

1. Voltage Management:
    a. Voltage Issue 1 - Voltage dropped below American National Standards Institute limits because of extended feeder length under outage reconfiguration. Approximately half of the devices had remote monitoring to provide visibility into low voltage issues, but the other half did not. Some customers outside the Control Center's voltage visibility reported voltage as low as 96V at their houses.
    b. Voltage Issue 2 - A Woonsocket load tap changer ("LTC") set point adjustment was needed to compensate for the higher voltage drop resulting in lower remote end voltage because of additional loading and extended feeder length. A crew was dispatched to manually change the LTC set point.
    c. Voltage Issue 3 – The system had high voltage while trying to get the first mobile generator to come online. The high voltage prevented the generator from relieving load for approximately two hours. Remote tripping of capacitors was used to reduce voltage, but further voltage reduction was required. A crew was dispatched to adjust an upstream non-advanced regulator. Manual tap position adjustment of the generator's step-up transformer and generator control power factor adjustment were ultimately necessary to bring the voltage within an acceptable range to bring the unit online.

Prepared by or under the supervision of: Ryan Constable

   d. Voltage Issue 4 - A non-advanced regulator controller had a controller failure during the event resulting in high voltage. Crews were dispatched to troubleshoot the controller.
2. Loadflow Analysis:
   a. Loadflow Issue - Modeling the reconfigured system to perform load flow simulations that assessed potential contingency actions was necessary to support operations. It was difficult to perform these assessments with offline simulation tools because of repeated manual entry of multiple meter data points that was required to make the offline model sufficiently accurate to aid contingency planning.
3. Distributed Energy Resource ("DER") Dispatch:
   a. DER Dispatch Issue 1 - Pascoag Municipal's battery dispatch was conducted through phone calls between Rhode Island Energy's Control Center and Pascoag Municipal personnel. The daily dispatch was setup each morning. Although the initial daily battery dispatch setup was reasonable, cloud coverage of large photovoltaic ("PV") sites on the 26W1 feeder combined with the battery charging schedule sometimes exacerbated loading issues. Operations needed to quickly adjust and readjust through phone calls with Pascoag Municipal personnel to change the battery status.
   b. DER Dispatch Issue 2 – PV generation sites tripped because of large voltage deviations, which resulted in excessive feeder loading.
4. Load Management:
   a. Loading Issue 1 – Crews had to be dispatched to switch locations for initial restoration and to restore the system to normal configuration.
   b. Loading Issue 2 - A large customer was asked to curtail their operations during the event to avoid system overloads. The customer shutdown their operations for approximately two days.
   c. Loading Issue 3 – Because the system was near its loading limits, load shed plans were developed. Customer communications were distributed for potential evening load shed needs during the immediate days following the station event. Although no load shed actions were taken, the proposed actions were developed using existing switch and protective device locations.

GMP Actions and Equipment:

   a. Voltage Visibility GMP Benefit – More granular voltage visibility along feeders would allow operations to respond to more voltage issues before customer

b. complaints or equipment damage occur. This would be accomplished with an ADMS system, communication system, advanced capacitors and regulators, and real-time loadflow.
c. Distribution Voltage Operational GMP Benefit 1 - Remote switching of capacitors and regulators would solve voltage issues and DER dispatch issues without dispatch of line crews. This would be accomplished with an ADMS system, communication system, advanced capacitors and regulators, and real-time loadflow.
d. Distribution Voltage Operational GMP Benefit 2 - Remote control of capacitors and regulators would inform the Control Center of equipment or control issues before those equipment issues become critical. This would be accomplished with an ADMS system, communication system, and advanced capacitors and regulators.
e. Substation Voltage Operational GMP Benefit - Remote adjustment of LTC controls could have avoided the need to dispatch a crew to adjust the LTC manually. This would be accomplished with an ADMS system, communication system, and sensing from advanced capacitors and meters.
f. Real-Time Load Flow GMP Benefits - Real-time load flow tools would have merged real-time system configuration and meter data into the model automatically for fast simulations to evaluate potential contingency actions. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, and real-time loadflow.
g. DER Dispatch GMP Benefit 1 - Direct control of battery storage would allow for a faster coordinated response to provide optimal feeder load management during significant loading or generation changes. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, real-time loadflow, and a DER monitor/manage system.
h. DER Dispatch GMP Benefit 2 - DER monitor/manage would enable volt/var inverter controls that regulate voltage locally at PV sites to prevent tripping and prevent voltage swings should nearby sites trip or cloud cover occur. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, real-time loadflow, and a DER monitor/manage system.
i. Load Management GMP Benefit 1 – Advanced reclosers would provide system self-healing and quicken restoration. This would be accomplished with an ADMS

j. system, communication system, advanced reclosers, sensing from capacitors, and meters, and real-time loadflow.
k. Load Management GMP Benefit 2 – With the monitoring, load flow, and voltage control benefits of GMP, the large customer's load could have been managed to avoid shutdown. This would be accomplished with an ADMS system, communication system, sensing from capacitors, reclosers, and meters, and real-time loadflow.
l. Load Management GMP Benefit 3 – Load shed plan could be developed at a much more granular level, potentially to the individual meter. This would be accomplished with an ADMS system, communication system, sensing from capacitors, reclosers, and meters, and real-time loadflow.

GMP Benefits Quantification:

The following benefit quantifications are estimates, not actuals, and have been developed for the Company's response to this data request. Rhode Island Energy does not typically quantify benefits for a specific outage event. The pending GMP calculates systemwide benefits in a similar manner to the items below.

a. Avoided Crew Dispatch for Switching – Approximately two crews for five hours would have been avoided at the beginning and end of the system reconfiguration duration for a total of $7,500.
b. Avoided Crew Dispatch for Troubleshooting – Approximately five crew dispatches would have been avoided at $1000 per dispatch, equaling $5,000. This includes crew, operator, and engineering time. The failed regulator control required significant resources and time, so this estimate may be conservatively low.
c. Value of Self-Healing – The United States Department of Energy ("USDOE") Interruption Cost Estimate ("ICE") Calculator was used to evaluate the first two switching steps as self-healed. A value of $480,000 was calculated.

d. Value of Customer Curtailment – USDOE ICE Calculator was used to evaluate the large customer shutdown for two days. A value of $24,000 per day was calculated, or $48,000 total for the two days.[1]
e. Value of Real-Time Loadflow – Time for two engineers for three days at a total of $9,000

Other system level benefits have not been quantified. For example, Control Center efficiencies have not been quantified. These would include switching order development and execution, operator time savings associated with access to real-time load flow, and faster decision making with access to granular system data.

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[1] Pending customer claim is reportedly in the vicinity of $120,000, suggesting it is possible that the ICE Calculator is conservatively low in this instance.

Division 1-34

Request:

The Company presented Northwest Rhode Island (NWRI) Area Study results to the Division on April 28, 2020 which included Nasonville Substation. At the time, the Company identified 13 MVA or 350MWH of unserved load for a transformer failure at peak (Nasonville T2 is the single transformer at the substation). The unserved load would result after the Company completed load transfers and restoration efforts.

The Division followed up with an Information Request dated April 30, 2020, including the following Question #13:

On page 11 of the presentation, the Company states that loss of Nasonville T2 results in 13 MVA of unserved load at peak (350 MWHr). What is the Company's current restoration plan for loss of Nasonville T2? Provide details on switching schemes or load transfers, mobile installation, etc. For a mobile installation, include nameplate, where the mobile is stored relative to Nasonville Substation, timeframe to transport and connect the mobile, substation site characteristics that enable efficient connection or present challenges, protection scheme impacts or issues, etc.

The Company responded, in part:

There are three mobiles available for installation at Nasonville Substation, which are listed below. The order of preference for this location is Mobile No. 8094, 7408, 7704 with mobile regulator 8137. The selection of which mobile to deploy is based upon availability at the time of need. National Grid has a fleet of 10 circuit switch trailers and 20 mobile LV cable trailers that can be utilized as needed to complete the installation. The central storage location for this equipment is the Construction Depot facility in Whitinsville, MA located 25 minutes away. The timeframe to deploy the mobile as an emergency response is 8 hours. The response time is based on worst case and pertains to winter off hours and includes clearing, permitting, loading, and delivery of all the equipment.

a. Compare and contrast the Company's planned restoration with actual restoration results after the Nasonville incident.

b. Summarize the four options put forth in the NWRI Area Study to resolve the Nasonville contingency at risk and estimated costs, identifying the preferred option.

c. Describe the actual work being performed to rebuild Nasonville and alignment with the recommended option put forth in the NWRI Area Study. What is the total estimated cost and timeline for the substation rebuild?

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d. Describe any enhancements or changes being incorporated in the substation rebuild that were not contemplated in the Area Study, incremental cost associated with the enhancement, and rationale for construction deviations

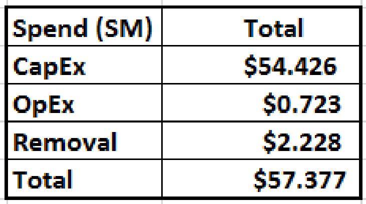
Response:

a. The Company's planned restoration differs with actual restoration results after the Nasonville incident because the planned restoration considered a transformer failure, and the actual event was a switchgear failure which included a station fire. The mobile switchgear was on site in approximately 12 hours, however the station damage due to the fire required over three days of repairs before the switchgear could be fully installed.

   Although the system impact between a switchgear and transformer are similar, there were no sustained outages during the actual restoration. This is because the event happened in late summer where loads where approximately 75% of peak. Also, a 4-6 MVA customer agreed to shut down for the first two days after the station event. Within three days of the station event, 9 MVA nameplate (7 MVA sustained operation) of roll-on generation was installed.

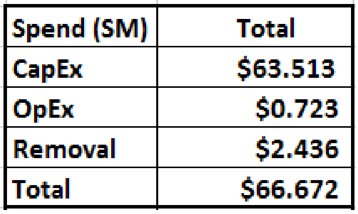
b. Option 1-New 115kV supply line from Woonsocket and station expansion.

   This is the preferred option which recommends installing a new 115kV bay at Woonsocket substation to bring a new 115 kV overhead supply line to Nasonville substation. The Nasonville substation will also be expanded by adding a second transformer and 13kV straight bus.



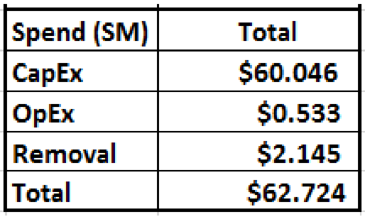
Spend (SM)	Total
CapEx	$54.426
OpEx	$0.723
Removal	$2.228
Total	$57.377

   Option 2–New 115kV supply line from Woonsocket and station rebuild.
   This option recommends installing a new 115kV bay at Woonsocket substation to bring a new 115 kV overhead supply line to Nasonville substation. The Nasonville substation will also be rebuilt in a breaker-and-a-half configuration with two transformers.



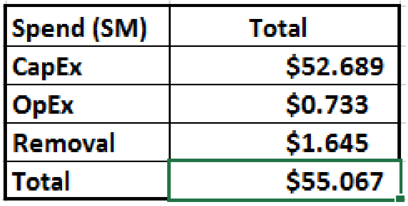
Spend (SM)	Total
CapEx	$63.513
OpEx	$0.723
Removal	$2.436
Total	$66.672

Option 3–New 115kV supply line from West Farnum and station expansion.
This option brings a new 115kV overhead line from West Farnum substation and expands Nasonville with a second 115kV/13.8kV transformer and a 13.8kV metalclad straight bus. This requires installation of a new 115 kV radial line with two breaker bays at West Farnum substation to bring a new 115kV line through the existing ROW.



Spend (SM)	Total
CapEx	$60.046
OpEx	$0.533
Removal	$2.145
Total	$62.724

Option 4–New 34.5kV supply line from the Iron Mine Hill Substation and station expansion
This option brings a new 34.5 kV overhead supply line from the Iron Mine Hill substation to Nasonville and adds a new 34.5/13.8KV transformer and straight bus with two feeder positions at Nasonville substation. This new supply line will be brought into the Nasonville substation throughout the existing transmission ROW.



Spend (SM)	Total
CapEx	$52.689
OpEx	$0.733
Removal	$1.645
Total	$55.067

c. The station will be rebuilt equivalent to the prior configuration incorporating PPL standards to the furthest extent possible. Currently, an open-air design will be used instead of the existing switchgear configuration to expedite the replacement. This new open-air station will be installed and fed with the existing transformer. This is aligned with the recommended option in that it restores the original functionality as it was at the time of the NWRI study. As the site is rebuilt, physical arrangement will include consideration of the study recommended option

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The total estimated cost of the replacement of the existing station is approximately $4.1 million. It is expected that the replacement will be complete the first quarter of 2024.

d. The recommended expansion of the station will be of the open-air design to match the station rebuild. As part of this design, there will be a tie breaker to allow the buses to be tied together to facilitate maintenance. The cost for the tie breaker is approximately $38,000.

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Division 1-35

Request:

Provide current copies of all planning policies, guidelines, and design criteria relied upon to develop the ISR Plan, including but not limited to Distribution Planning Guide, Annual Load Forecasting, Annual Capacity Review, Vegetation Management Guide, Overhead Line Patrol and Maintenance Policy, distribution design guidelines, Complex Project Delivery Stage-Gate Process, and Delegation of Authority and Sanctioning framework. For each, discuss whether the document is consistent with National Grid's policies or guidelines, and if not, describe the changes and resulting impacts to the distribution planning and project implementation process.

Response:

Please see attached all applicable documents related to the ISR Plan.

Distribution Planning Guide: Please see Attachment DIV 1-35-1. This is consistent with National Grid's policies and guidelines with minor changes to include changes in technology. This does not change the distribution planning and project implementation process.

Annual Load Forecasting: The load forecasts are being developed as a collaborative effort between the PPL Load Analytics & ISO Settlement group and the National Grid Load Forecasting group. There have been no changes to the load forecasting process under PPL ownership.

Annual Capacity Review: This remains unchanged from National Grid's policies and guidelines.

Vegetation Management Guide: Please see Attachment DIV 1-35-2. The specifications currently used for Vegetation Management are the same as National Grid's but are in the process of being revised. This has not affected the distribution planning and project implementation process.

Overhead Line Patrol and Maintenance Policy: Rhode Island Energy is drafting a new policy currently incorporating changes and anticipates it being complete in January. The Company will share with the Division once it is finalized and discuss the differences in comparison with National Grid's policies and guidelines.

Distribution Design guidelines: Please see Attachment DIV 1-35-3 for Overhead and Attachment DIV 1-35-4 for Underground policies. Rhode Island Energy has accepted the RI applicable National Grid standards as the starting point for distribution standards and are currently assessing best practices to implement in both PA and RI.

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Complex Project Delivery Stage-Gate Process: Please see Attachment DIV 1-35-5. The Complex Project Delivery Stage-Gate Process has minor differences compared to National Grid's Complex Capital Delivery Process for milestone names. These changes do not impact the distribution planning and project implementation process.

Delegation of Authority and Sanctioning Framework: Please see Attachment DIV 1-35-6. The new Delegation of Authority and sanctioning framework differ slightly from National Grid as it has been designed for a flatter, more localized organization. This is in the draft stage, as the Company is working on gaining alignment between both the electric and gas teams. This does not impact the distribution planning or project implementation, as sanctioning will occur at the same point in the process as it did at National Grid.

Integrated Electric System Planning Study Process

1. Introduction

In order to maintain a consistent approach to electric system planning, it is necessary that uniform planning criteria is followed and proper coordination among internal and external stakeholder groups is completed. This document has been updated with 'integrated planning' concepts including specific Distributed Energy Resource (DER) inputs and greater transmission planning consultation to provide guidance on the performance and expected work product of area planning studies.

2. Purpose

This document details the Integrated Planning and Asset Management study process for system planners, the functions that support them, and the stakeholders reliant on their work product. It is expected that execution of a well-defined study process will result in timely delivery of infrastructure development recommendations having thoroughly defined project scopes that satisfy the needs and expectations of all stakeholders (especially customers). In addition, it enhances the organization's ability to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

3. Applicability

This guide applies to all personnel within Distribution Planning and Asset Management assigned to work on:

- Integrated Area Studies
- Program Studies (initial or modification)
- Complex Customer Service Requirements Studies – Typically, large services requests, generally 8MW or greater and/or greater than 5MW with requirements for service redundancy

Members of departments that support the study process and associated work product development should be trained in and/or aware of this process.

Although there are many fundamental similarities, DER interconnection studies are covered in a separate interconnection guide.

4. Annual Planning

The prioritization of area planning studies to be executed and the engineering analysis conducted within an area study is supported by the Annual Planning Screening Process. This process is a recurring annual effort which aides in the identification of system performance concerns. As part of this effort, the following is historically recorded or estimated:

- Area (feeder, substation, and supply line) peak loads (date, time, and value) both coincident and non-coincident with the system peak load.
- System peak load (date, time, and value).
- Load forecast with energy efficiency (EE), distributed generation (DG), and electric vehicle (EV) inputs as load modifiers to the peak value. These forecasts include some regional differences
- Area (feeder, substation, and supply line) contingency loading during peak load.

As a result of evolving integrated planning needs, the following information will be added or changed:

- Area (feeder, substation, and supply line) light loads (date, time, and value). Where possible, obtain 8760 hour per year PI Historian load data.
- DG existing and in-queue locations and amounts
- Separate forecasts to be obtained for base load, EE, DG, EV, and heat electrification (HE) inputs as load modifiers to the peak value. These forecasts include some regional differences

- EV and HE existing and in-queue information when possible
- Existing Demand Response (DR) programs
- Existing Energy Storage (ES) locations and amounts.

5. Milestones and Consultation Guidance

Each area study generally follows a set of milestones to enable an efficient study process with robust consultation. Although stakeholder engagement can occur at any time, the following guide describes the content of each milestone and recommended consultation inputs:

- Scoping Activities
- Initial System Assessment
- Study Kickoff
- Detailed System Assessment / Engineering Analysis
- Plan Development and Project Estimating
- Identification of Recommended Plan
- Technical Review
- Documentation
- Sanctioning

Further detail on each of these milestones follows:

5.1. Scoping

This milestone includes:

- Gather the most recent version of the Distribution Planning Guidelines (“DPG”)
  - Upon consultation with the manager, gather any other emerging guidelines that have not been formally incorporated into the DPG (ex: grid modernization or volt-var optimization guidelines).
- Gather equipment rating data, settings data, specifications data, etc.
- Gather the most recent Distribution Standards including, but not limited to:
  - Overhead conductor ratings (section 6.0)
  - Generic underground cable ratings (section 35.14)
  - Latest recloser controls (pages 12-338 to 12-340)
  - Latest capacitor controls (pages 15-335 to 15-336, 15-404 to 15-405)
  - Latest sensor controls (page 15-600)
  - Storm Hardening (section 4.0)
- Define the electrical scope (lines and substations to be studied)
- Define the geographic scope (towns and portions or towns to be included in study)
- Build/update system models in CYME, PSS/e, ASPEN
- Gather the latest forecast and review/refine the area/facility load and expected load growth from the present to the study’s horizon year (typically 15 years)
  - Integrated Planning Update – Gather separate forecasts for load, EE, DG, EV, HE, DR, and ES. Gather 8760 hour yearly load cycles for each technology. If necessary, default load cycles can be used. Gather 8760 hour per year data for feeders, substation, and supply lines as available.
- Gather service territory maps
- Gather large commercial and industrial customer load data[1]
- Gather or request asset condition reports[2]
- Identify all infrastructure development limitations (ex: river, highway, state forest, etc)
- Gather documentation of existing system performance concerns (ex: thermal, reliability, voltage, reactive support, arc flash, fault duty, etc.)[3]

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[1] Consult with Customer and Community

[2] Consult with Substation O&M Services

- Gather recently completed area projects or ongoing area projects within the work plan. This will set the base year and base configuration.[4]
- Gather existing and in-queue distributed generation or distributed energy resources
- Gather state information or policies regarding distribution planning or distributed energy resources

The engineer will then develop a scope that details the study area boundaries and concerns. The study scope will be reviewed by their respective manager. The manager must approve the study scope before next steps are executed.

The final scoping activity is to request study team members. The study engineer will request formal team members from the following departments, via Study Engineering Request form.

- Transmission Planning
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering (Relay, Communications, and Controls and Integration)

The following additional departments may be expected to provide input during various stages of the study and will be included in study meetings as required:

- Substation O&M Services Operations
- Transmission Control Center and/or Regional Control Center
- Project and Program Management
- Community and Customer Management
- Distribution Design
- Safety
- Environmental
- Legal
- Real Estate

All study contributors will be provided proper accounting to charge their time in support of the study. Once a study team is formed, the study engineer will schedule the study kickoff meeting.

5.2. Initial System Assessment

Study area initial system assessment consists of a quick analysis of facilities and system performance within the identified study geographic and electric scope. As part of the assessment, the study engineer will conduct the following:

- Existing and in-queue distributed generation and distributed energy resources
- A review for compliance with Planning Guidelines:
  - Thermal (load vs. capability) issues using the annual planning screening spreadsheet, CYME, and PSS/e

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[3] At a minimum, include annual plan screening information. Consult with area engineering and operations experts as time allows.

[4] For example, a study starting in year X may set a base year of X+3 if substantial system modification will be completed in year X+3.

  - Voltage – using CYME, PSS/e
  - Reactive Support
- Asset condition assessments and consideration of active asset programs including, but not limited to:
  - Breaker Replacement
  - EMS
  - Metal Clad Substations
  - Indoor Substations
  - Underground Cable
  - Distribution Line Inspection & Maintenance
- Screening review of arc flash and fault duty data
- Screening review of CKAIDI and CKAIFI reliability indices[5] against state targets or average values

Initial system assessment is completed when the planner has enough information to consult with the wider group of subject matter experts and internal departments at the study kickoff. A careful balance of analysis to ensure study timeline efficiency is required. Too little analysis leaves the planner unable to lead a robust discussion during the kickoff meeting to gather asset, operational, and construction complexities that help refine issues and generate comprehensive alternatives. Too much analysis may lead to rework by the planner should new information result from the kickoff. It is preferable that high level alternative concepts are developed during Initial System Assessment simply to generate discussion. Never should alternatives be fully developed or considered final within this step. Throughout the Initial System Assessment, it is expected that informal and regular consultations will be required with Transmission Planning, Distribution Design, Substation Engineering, Transmission Line Engineering, Substation O&M Services, and/or Operations.

5.3. Study Kickoff

The study kickoff is a meeting held to inform the larger stakeholder group that an area study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review.

The study engineer will invite the following groups/representatives to the Kickoff meeting:

- Community & Customer Management
- Operations:
  - Distribution Line (OH & UG) Supervisors
  - Substation O&M Supervisors
  - Distribution Design
- Substation O & M Services
- System Control Center
- Project Management
- Program Management (Substation and Line)
- Distribution Engineering and Asset Management
  - Field Engineer
  - Field Engineering Manager
- Transmission Engineering and Asset Management
  - Transmission Planning Engineer
  - Transmission Asset Management Engineer
- Transmission Line Engineering

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[5] 5-year reliability data is preferred. 3-year data may be used to avoid years of significant major storm activity or significant system reconfiguration.

- Substation Engineering
- Protection Engineering
- Resource Planning
  - Short Term Resource Planning
  - Long Term Resource Planning
- Product Energy Services (NWA)
- IT/ IS

The study engineer will present the following:

- Proposed study electrical and geographic scope
- Recent area studies and infrastructure development projects impacting the area
- Study area load and initial understanding of load growth expected in the area
- Known concerns in the area
- Using one-lines, possible infrastructure development plans for discussion
- Using area maps, possible distributed energy resource ideas for discussion
- Study schedule and the names of representatives of departments assigned to support it

Upon completion of this presentation, the study engineer will open the meeting for group discussion. Specific input that the study engineer is looking for includes:

- Acceptance of electrical and geographic boundaries
- Operational concerns, examples:
  - Switching flexibility
  - Restoration areas of concern (ex: rights-of-way, direct buried cables)
- Asset condition concerns not already identified
- Safety by Design
- System performance concerns not already identified, examples:
  - Reliability
  - Voltage
  - Loading
- Details on any significant near-term load additions in the area not already identified
- Details on any significant distributed energy resources in the area not already identified
- Details on potential alternative ideas or concerns, examples:
  - Locations that should/could be considered for new substation development
  - Substation expansion opportunities
  - Feeder routing (new feeders and feeder ties)
  - Local issues that might impact infrastructure development options, examples
    1. Local regulations requiring underground vs. overhead construction
    2. Status of community relationships with the Company
- Details on any distributed energy resource opportunities that should be considered

Representatives assigned from all groups are expected to support the study throughout the entire process and document any concerns their department may have along the way.

All individuals invited to the kickoff meeting should be asked to forward the meeting notice to any other individuals they would like to have take part in the meeting.

It is expected that the study engineer will prepare minutes of this meeting. Minutes will be shared with all those invited to participate in the meeting.

5.4. Detailed System Assessment / Engineering Analysis

The study engineer will utilize input received at the study kickoff meeting in subsequent detailed analysis and comprehensive plan development. All area distribution studies will require the same basic analysis steps.

The study engineer should look to optimize existing system performance and identify any common infrastructure development needs of the area prior to engaging in the detailed analysis associated with finalizing the development of alternative plans. Simple no-cost or low-cost system adjustments such as switching or load balancing can be progressed immediately by the planner and do not need to be formally included in the study report. Instead, the study base case should be adjusted to include these simple changes.

The study engineer should:

- Conduct system fault studies, associated protective device coordination, and breaker capability reviews
- Conduct incident energy calculations (arc flash)
- Conduct system thermal assessments
- Conduct system loss studies
- Conduct system reliability assessments
- Conduct system voltage performance evaluation
- Analyze Distributed Energy Resources (DER) impacts

Typical Analysis tools:

- PSS/e load flow software for analysis of:
  - Supply system (transmission and sub-transmission)
  - Network system
- CYME and other radial distribution feeder analysis software
- CYME, ASPEN, and other protective device coordination software including short circuit analysis
- ArcPro for Arc Flash analysis
- GIS systems
- Annual Planning Screening Spreadsheets
- Equipment ratings programs
- Cascade and other asset information systems

Note that the presentation of results and defense of recommendations is significantly enhanced by the functionality of these tools (particularly load flow and radial distribution feeder analysis software). These tools will strengthen response to questions posed during the review of recommendations. These tools enable quick evaluation of “what if” questions that could otherwise cause unacceptable delays in study delivery.

5.5. Plan Development and Project Estimating

Once the engineering analysis is performed, the study engineer develops and refines alternative infrastructure development and non-wires alternative plans and updates associated plan one-lines. The plans should be technically comparable to the furthest extent possible. Infrastructure and non-wires alternatives can be combined to create comparable plans.

The following team members/departments will provide a feasibility review of these one-lines:

- Field Engineer
- Substation Engineer

- Transmission Line Engineer
- Distribution Design Engineer
- Operations
- Transmission Planning

OPTIONAL - It is suggested the planner gather all internal stakeholders[6] at a Plan Development meeting to review and gain acceptance of the various plans immediately prior to requesting estimates. It is important that the various engineering functions understand the interrelationship between their individual portions of the comprehensive plans. Without this review, it is often difficult for the engineering functions to understand the segmented nature of estimate requests.[7]

As the one-lines and plans are modified with this cross functional input, engineering analysis will be refined as needed to accommodate for any scope changes. Once the plans and one-lines are completed, the study engineer will request study estimates from the respective team members (substation engineer, transmission line engineer, and distribution design engineer) for all alternative plans.[8]

It is expected that estimates will be returned within 8-12 weeks of the request date. Estimators will use primary equipment scope and known field conditions along with recent costs for comparable projects to develop estimates. Field visits are not required but are encouraged especially if constructability or future system maintenance (ex. R/W accessibility) is a concern. Estimates are expected to be suitable for plan comparison/selection and enable initial partial sanction of more detailed engineering activities. Substation and transmission line conceptual engineering reports and estimates may be requested if they can be completed within the 8-12 weeks. Distribution line estimates can be completed by the planner using the Company’s Success Enterprise estimating tool and can be considered at a conceptual level of accuracy.

Note: When considering alternate locations for a new substation. The site where a new substation will be constructed should be selected by the sponsor with input from the project team. Where alternate sites are required for regulatory reasons or are desirable for other reasons, those alternate sites should also be selected by the sponsor. In addition to the engineering requests, sites should be assessed for other flaws that could warrant them unsuitable for use. These “due diligence” assessments for potentially “fatal flaws” should be performed by the following departments and reported to the sponsor: Environmental, Real Estate, Legal (Siting), Project Management, and Construction or Operations.

While estimates are under development, the planner should organize and document the technical benefits and issue resolution of each alternative. The planner has discretion to the level of analysis for alternatives that are expected to be economically non-competitive.

Once the study estimates are returned, the study engineer will review and finalize the identified plans. Study team members will be asked to note their agreement with the scope of projects estimated.

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[6] Similar to the kickoff meeting invite list

[7] For example, a substation request that asks for a common item such as a capacitor bank to be estimated separately from a feeder position which may be an alternative plan.

[8] Requests should be well documented with clearly defined one-line scope diagrams, using

5.6. Identification of Recommended Plan

As part of this phase, the study engineer reviews the various alternatives with costs, identifies, and finalizes a recommended plan. Once the recommended plan is identified, the study engineer completes (with team member assistance as required):

- Economic comparison of plans
- Technical comparison of plans if not equivalent
- Performance of an environmental and safety review of recommended plan
- Identification of the system outages required to implement the recommended plan
- Statement or summary of alignment with Climate Resiliency standards[9]
- If not formally evaluated as a criteria, strategy, or program within the study, include a statement or summary of alignment with potential or pending Grid Modernization concepts.[10]
- Review of the recommended plan project implementation schedule[11]

The planner should summarize recommended plan risks to the furthest extent possible. For example, permitting or site acquisition delay risks could be noted with the system issues that may result. Potential mitigation concepts, including acceptance of risk, can be described. This is not intended to be an exhaustive review and it is noted that significant internal department consultation and support is necessary. Instead, this risk analysis is only intended to help or guide future efforts.

Once all this analysis is completed and documented, the study engineer updates the project team members on the final recommended plan.

5.7. Technical Review

This meeting will be held once the planner has completed the majority of the study analysis and after an internal review in Distribution Planning and Asset Management has been completed, but prior to the formal study document approval process.

The primary purpose of this meeting is to give those who will be asked to approve the area study report an opportunity to hear a presentation and ask their own questions on the overall study effort. It is expected that this meeting will facilitate the study report approval process that will in most instances follow soon after.

The presentation will provide a description of the issue identification efforts and a comparison of all plans, including estimated costs, describing the advantages and disadvantages of each.

The planner will cover the following topics in presentation format during the meeting. The presentation will be split (between Distribution Planning and Transmission Planning) if study responsibility is split.

- Study scope (electric system one-lines and map of area)
- Study area load and load growth
- Additional study assumptions
- System performance concerns identified (existing and predicted)
- Plans considered to address concerns with detailed description of the scope of proposed projects, time and cost required to implement, technical differences, as well as unresolved stakeholder concerns

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[9] All recommendation should be built to the latest storm hardening and substation flood mitigation standards
[10] For example, use of latest controls that prevent near term obsolescence
[11] Consult with Long Term Resource Planning for implementation schedule and cash flow assistance.

- Plan recommended to address concerns with detailed description of the scope of proposed projects, time, and cost required to implement

Meeting participants are expected to constructively challenge study assumptions and analysis (ex. load growth assumptions, load flow models, equipment ratings, interpretation of planning criteria in determining violations, etc.) and the plans developed to address area concerns. If a specific project's scope of work is in question (ex. asset condition concerns not addressed) and can not be resolved in this meeting, the Study engineer will set up subsequent meetings with the project team for more detailed discussion and problem resolution.

The following groups/representatives are part of the Technical Review meeting governance:

- Asset Management (NY or NE), including:
  - Vice President Asset Management
  - Director Distribution Planning and Asset Management
  - Manager of Asset Management
  - Director of Transmission Planning and Asset Management
  - Manger of Transmission Planning
- Electrical Systems Engineering, including:
  - Vice President of Electrical Systems Engineering
  - Director of Substation Engineering Design
  - Director of Protection Engineering
  - Director of Transmission Line Engineering
- Operations (NY or NE), including:
  - Vice President of Operations
  - Director of Distribution Design
  - Director of Overhead Lines
  - Director and Manager of Substation O&M
- Dispatch and Control, including:
  - Vice President of Control Center Operations
- Jurisdictional Leadership, including:
  - Jurisdictional President
  - Community and Customer Management, Director
- Representatives assigned from all groups that are supporting the study (attendance required)

5.8. Documentation

The area study report is the primary documentation delivered upon completion of the area study. This report becomes a source document for many other forms and reports (used both internally and externally). As such, the importance of form and order in reports be as consistent as possible.

In order to properly complete the report template, the study engineer will need to have done the work necessary to prepare the following general report sections:

- Executive summary, including:
  - Explanation of why the study was done and the major concerns/needs for the area
  - A brief description of the alternatives considered
  - A brief description of the recommended plan
  - Reasons for the recommendation
  - Cost and cash flow of the recommended plan
- Introduction, including:
  - Purpose statement
  - Problem statement

- Background, including:
  - A statement on all items gathered in Section 4.1
  - Versions or dates of guidelines, standards, forecasts, databases, screening work, and software used
- Problem/Issue Identification, including:
  - A summary of all analysis done in Sections 4.2 and 4.4
- Plan Development, including:
  - A summary of all efforts done in Section 4.5
- Description of recommended plan, including:
  - A summary of the comparative analysis and conclusions made during Section 4.6
  - A clear summary of the sequencing of projects, project dependencies, proposed cash flow, and risks.
- Conclusion and factors affecting future studies
- Appendices, including but not limited to:
  - Geographic study area maps
  - One-line diagrams for stations, sub-transmission systems, and circuit tie maps - base case and recommended plan
  - Feeder rating sheets
  - Existing and in-queue Distributed Generation tables
  - Annual Plan screening tables – base case and recommended plan
  - CYME, PSSE, and Aspen screens and tabular exports - base case and recommended plan
  - Strategy or program tabular details including criticality rankings
  - Arc flash tables - base case and recommended plan
  - Reliability indices tables
  - Fault duty analysis tables - base case and recommended plan
  - Estimate data

Appendix A and B of this document provide a detailed outline of area study and program study report content respectively.

Study reports will be issued following the Study Results presentation (and resolution of any issues it raised). The report will be electronically issued with a cover letter to the following individuals for approval:

- Respective Manager of Distribution Asset Management
- Respective Director of Distribution Planning and Asset Management
- Vice President Asset Management

The study report will be electronically stored on Distribution Planning and Asset Management's SharePoint site.

It is expected that the Customer and Community Management group will communicate the recommended plan with external stakeholders as appropriate. Consultation with jurisdictional leader for approval of the external communication plans is required.

5.9. Sanctioning

It is expected that the study engineer will, upon study approval, seek initial sanction of any recommended projects having forecasted spending within the next three fiscal years.

6. Appendix A

Study Report Table of Contents

Appendix B

Program Report Table of Contents

FOREWORD

This specification documents the objectives, practices and procedures for vegetation management on Rhode Island Energy company distribution circuits in **Rhode Island only**. The specification also defines the responsibilities of Rhode Island Energy vegetation management personneland contractors, identifies procedures to be followed by contractors performing all work and defines the requirements to maintain vegetation acceptable to the Company.

Questions or inquiries regarding information provided in this document should be referred to the Rhode Island Energy Manager of Vegetation Strategy.

Christopher J Rooney
Manager
Rhode Island Energy T&D

Date of Review/Revision:		
Revision	**Date**	**Description**
0	11-7-2022	Original Specification

Rhode Island Energy™
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RI DISTRIBUTION LINE CLEARANCE SPECIFICATIONS Date 11-7-2022

I. Scope/Intent

1.1 These specifications cover the cutting, clearing, pruning, tree removal and herbicide treatment of vegetation along overhead electric distribution lines and the corresponding substations. The intent is to define the minimum clearances to be obtained between the overhead conductors and vegetation that will be acceptable to RI Energy. These specifications are strictly for use on overhead line maintenance pruning projects. This is not a specification to be used for enhanced hazard tree removal, new construction clearing or rebuild construction clearing.

II. Program Objectives:

2.1 The goals and objectives of the RI Energy Distribution Line Clearance program areto provide safe, reliable, electric service through a cost effective, integrated vegetation management program. RI Energy acknowledges differences in the manner in which various landowners respond to the need for routine line clearance activities, together with occasional differences in easement rights. Therefore, these specifications are designed to address:

- the minimum clearance requirements necessary to sustain safe, reliable electric service while striving to satisfy the concerns of sensitive customers,
- and the optimum clearance requirements necessary to sustain an appropriate level of safety and reliability.

III. Definitions:

Maintained Area: Generally defined as an area where the landowner or occupant is mowing the lawn and/or caring for gardens, ornamental shrubs or trees in the area under and immediately adjacent to the distribution poles. It includes commercial land uses such as business areas, parking lot edges and the tree lawn areas along urban and suburban streets. Un-maintained areas, of course, hold the opposite of these characteristics. It should be noted that within residential (maintained) areas there may be small sections of un-maintained property between yards or along the roadside of residential front lawns, etc. These small sections shall be treated as maintained areas for the purposes of this specification.

Mature Tree Line: A generally straight and contiguous line of trees nine (9) inches d.b.h. or greater, that mark the boundary between the forested edge and the maintenance corridor. In the case of an existing mature tree line, there may be individual mature trees that are rooted closer to the pole centerline than the common mature tree line. In these instances the mature tree line continues behind those individual trees.

Maintenance Corridor: The area physically located under and alongside the overhead distribution feeder bounded by the mature tree line when one exists. In the absence of a mature tree line the maintenance corridor is defined as the area that is at least ten (10) feet either side of the pole centerline or equal to the previously maintained dimensions if greater than ten (10) feet.

Service Drop or Service Line: The last span of triplex or open three wire extending to the building or meter pole or a multi-span run of either triplex or open three wire that serves a single customer. This does not include street light services.

Secondary: The conductor, either triplex or open wire, which extends from the transformer to the Service Drop. Secondary spans may run along under primary spans or separately.

Street Light Secondary: The conductor, either triplex or open wire, which leaves the primary pole to pole configuration and extends out to service a street light or lights.

IV. Scope of Work:

4.1 Pruning Standards: All pruning shall be performed in accordance with ANSI A300 standards as well as the Best Management Practices – Tree Pruning publication. All cuts shall be made at a parent branch or limb, so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch or node where the branch being removed is at least one-third the diameter of the parent limb. All pruning cuts shall be made in accordance with proper collar cutting methods, utilizing drop crotch principles to minimize the number of pruning cuts, promote natural growth patterns, and maintain tree health and vigor (ANSI A300). Climbing irons or spurs shall not be used in pruning a shade/ornamental tree to be saved. Tree wound dressings shall not be applied.

4.2 Line Clearance within Maintained Areas: All overhead primary lines shall be pruned to provide a minimum of ten (10) feet of overhead clearance, a minimum of six (6) feet of side clearance from the outermost phase and a minimum of ten (10) feet of clearance below the wires. The contractor shall recognize that the use of ANSI A300 standards and techniques will result in clearances beyond the dimensions noted above.

4.2.1 The main trunk of the tree or major leads which are structurally sound and healthy may be left growing within these distances as long as none of the smaller diameter end branches are within the clearance dimensions. In that case the lead must be removed.

4.2.2 Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.2.3 The contractor shall ground cut any new volunteer growth capable of growing into the wires from around poles, guys, fences, etc. within the maintained yard areas after notifying the property owner.

4.2.4 It is an objective of Rhode Island Energy's program to continually strive to reduce the number of under-wire tree and branch growth that will continually require pruning, by removing as many stems and growth as possible on each cycle. The Contractor is expected to emphasize this type of removal through the landowner contacts made by their customer contact personnel.

4.2.5 Contractor shall exercise extreme care when pruning ornamental plantings. Species, growth rates and growth characteristics should be taken into account and may require differing clearances.

4.2.6 All slash from pruning in maintained areas shall be disposed of through chipping. Large diameter wood may remain on site provided it is cut into manageable lengths and piled neatly. Smaller debris shall be raked up and removed so as to leave the property in a condition equal to the start of work.

4.3 Line Clearance Outside of Maintained Areas: All overhead lines shall be pruned to provide a minimum of fifteen (15) feet of overhead clearance and six (6) feet of side clearance from the outermost phase.

4.3.1 Along off-road sections the contractor shall completely remove all side branches that extend into the maintenance corridor from below and beside the lines in order to "box out" the maintenance corridor. This practice will minimize future pruning efforts as well as improve storm restoration and line inspection efficiencies.

4.3.2 Where greater clearances have been achieved in previous cycles, the pruning shall be completed so as to re-establish the clearances in a manner that equals or exceeds the previous clearance conditions.

4.3.3 The contractor shall ground cut all trees and shrubs which have the ability to interfere with the conductor out to the limits of the existing maintenance corridor. Where a maintenance corridor does not already exist, ground cutting shall be performed for a minimum distance of ten (10) feet either side of centerline. Ground cutting shall include stems of eight (8) inches d.b.h. or less, all as part of the fixed price bid. Along individual spans that have been previously maintained using RI Energy's past eight (8) foot targeted ground cutting specification (trimming and removal) the same approach shall be utilized.

4.3.4 Where trees beyond the limits of the maintenance corridor are extending into the corridor, the contractor shall either prune those limbs back or have the option to remove the tree as part of the fixed price bid. For trees, eight

(8) inches d.b.h. or less, where the top of the tree is leaning out into the corridor so that topping would be the only possible correction, the contractor shall ground cut that tree as part of the fixed price bid.

4.3.5 Stumps shall be cut flat and as close to grade as possible.

4.3.6 All slash along the roadway or near residences shall be disposed of by chipping or mowing/mulching. Where practical, chips may be blown back onto the site without creating large chip piles. On off-road, un-maintained sites, slash shall be mowed/mulched or neatly windrowed to the edge of the maintenance corridor and cut to lie close to the ground, away from sensitive locations. No debris shall be left anywhere that will potentially block access, significantly alter any drainage or water resource, or create any unsafe condition for the public. Alternatives to these practices must be approved by Rhode Island Energy's Forestry representative and by the current landowner.

4.44.4 All dead or damaged overhead limbs over 8" D.B.H., branches or leads that are capable of falling onto overhead primary wires from above or along side the right-of-way and potentially causing a tree outage, shall be removed at the time of pruning, and included in the fixed price bid.

4.54.5 For all pine species growing above the overhead clearance limits with boughs overhanging primary conductor - the contractor shall shorten all overhanging boughs so to reduce the length of the branch by approximately 1/3 without removing all needle growth from the entire branch. This shall be done in a progressive manner beginning at the upper clearance dimension (10 or 15 feet) and working upwards generally two (2) whorls in the tree as necessary to reduce the likelihood of a long pine bough loaded with ice or wet snow, drooping down or breaking onto the conductors.

4.6 Pruning Clearance for Secondary and Service Lines:

4.6.1 All secondary wire (triplex and open wire), other than that serving street lights only, shall be pruned to provide a minimum of eighteen inches of clearance from wire to vegetation.

4.6.2 All service wires (triplex or open wire) and street light secondary on the circuit shall be inspected at the time of scheduled vegetation maintenance. For branches that are either making hard contact with the service wire, pushing on or creating tension enough to force the wire out of a natural arc, or redirecting the wire out of a straight-line run, the vendor shall do whatever pruning is necessary to correct that situation. The entire service drop need not be pruned, only the point of conflict.

4.6.3 For open wire services, pruning is required for all the situations noted in 4.6.2 as well as anytime vegetative growth is forcing the three wires out of their normal configuration. The vendor must take extra care when pruning around open wire services so not to cause a service interruption to our customers.

4.74.7 Multiple Circuits and Under-builds: The contractor shall prune all distribution circuits on a pole unless otherwise called out on the bid documents. Where a distribution circuit is under-built below a sub-transmission the contactor is responsible for the pruning of both the distribution circuit as well as the over-built circuit utilizing the specification of the higher voltage circuit unless otherwise directed in the bid documents. The contractor is also responsible for work on any primary, secondary or service tap running off the sub-transmission line along that specific distribution circuit. Any exceptions to the above will be explained at the time of bidding. Reference the appropriate sections of either RI Energy's Sub-T IVM and/or Sideline specifications depending on the under-built situation.

4.8 Circuits along Transmission Rights-of-Way: The contractor shall employ this specification on all sections of distribution circuits that run along segments of transmission rights-of-way except for areas where the distribution circuit is actually under-built on the same pole. In those cases the above section will apply. Any exceptions to the above will be explained at the time of bidding.

4.9 Substation Clearances: All vegetation within 10' of the substation fence shall be pruned, from ground to sky, removed and chipped and no overhanging branches shall be allowed to remain. Where shrubs and trees have been planted for screening purposes and are rooted within the 10' distance, only the fence side branches shall be removed. Any volunteer growth (natural regeneration) rooted within the 10' distance shall be removed.

4.10 Vine Control: All vines growing on poles, guy wires, stub poles or towers shall be cut so as to create a "growth gap" of 4 feet and treated (where appropriate) with a herbicide approved by the company.. Contactors should not attempt to remove vines from any structure.

4.11 Hazard Tree Inspection and Removal: Other than work required in previous sections, the removal of any tree over 8 inches d.b.h. within the maintenance corridor or outside the maintenance corridor shall be considered a hazard tree removal and is outside the fixed price bid.

4.11.1 While pruning the circuit, the contractor's personnel shall perform a visual inspection of each tree along the circuit in order to identify potential defects and determine the potential risk for the tree to cause an interruption over the length of the pruning cycle. The crew shall work closely with an Rhode Island Energy Forestry representative to determine potential hazard trees, preparing a list of trees in accordance with Rhode Island Energy's Hazard Tree Reporting Form. The completed lists of potential hazard trees shall be regularly provided to the Forestry representative for review and approval prior to removing any of those specific trees. Exceptions to this procedure may be approved to enable removals of trees that have been pre-identified as hazard trees by RI Energy representatives, trees that pose an imminent risk, or to authorize hazard tree removals in off-road areas where a skidder bucket is already on site.

4.11.2 Once a crew completes the removals on an approved list they shall note the completion details on the Hazard Tree Reporting Form. This form shall be submitted to the Forestry representative on a timely basis. Once the list is audited the contractor may submit an invoice for that specific work.

V. Contractor Requirements

5.1 The Contractor shall do all work and furnish all labor including supervision, tools, machinery and transportation necessary for the pruning, removal and herbicide treatment of trees to provide acceptable vegetation clearance for overhead lines of Rhode Island Energy. Work at the fixed price rates will be designated on the distributioncircuit maps, and identified in the pre-bid documents. Work at the fixed price is based on overhead primary miles of line, and includes pruning, tree and lead removal and herbicide treatment to all primary, secondary, service drops, and substation fence areas as clarified in the Work Scope section of this specification. Work at unit prices and/or hourly rates as also defined in the Work Scope section will be designated at the pre-bid meeting or by a Rhode Island Energy Forestry representative as required.

VI. Contractor's Responsibility

6.1 The Contractor shall provide all necessary supervision, labor, material, tools and equipment for the safe execution of all work covered by these specifications.

6.2 The Contractor shall employ a competent field supervisor and customer contact person(s) acceptable to the Corporation, in addition to the crew Foreman and senior Company management. Notification personnel shall be qualified in tree identification including identification of “proper under powerline trees”. The supervisor shall be available to the Corporation at all reasonable times during the entire extent of the project and/or contract. In addition, at least one member of each stand-alone crew or unit of crews shall be fluent in the English language and on-site.

6.3 The Contractor shall comply with all building and sanitary laws and all Federal, State, County, Town and Municipal laws, ordinances and regulations pertaining to the work. The contractor shall be responsible for obtaining all permits necessary to perform the work unless otherwise provided by Rhode Island Energy.

6.4 The Contractor shall notify each landowner and inform them of the clearing, removal, pruning and herbicide work to be done, and where appropriate, agree on access point(s), before crossing the property and then abide by the same. The Contractor shall designate a Customer Contact Person(s) for each project they are awarded and communicate that name and phone contact information for that person to the Rhode Island Energy forestry representative for that project.

6.5 In the event that the Contractor cannot locate the landowner after using all reasonable measures, or upon locating them is aware of an objection to the work to be performed, the Contractor shall document the landowners concern and then notify the Rhode Island Energy's forestry representative within 24 hours in order to obtain specific instructions and/or their permission prior to commencing work onthat property.

6.6 In addition to the above notifications, where herbicide applications will be made, the Contractor must follow any and all current notification requirements of any applicable regulations.

6.7 The Contractor shall be held solely liable and indemnify Rhode Island Energy fully for any and all claims and legal expenses for damage to crops, land, trees or otherwise resulting from such violations, failure or damages arising out of the Contractor's negligence. The Contractor shall not be liable for claims or suits for damage to property if the work causing such damage is done under specific direction from RI Energy.

6.8 The Contractor shall replace or make necessary repairs to all property destroyed or damaged in the course of the work and exercise due care and diligence in adequately protecting all properties, both real and personal, from damage of whatsoever nature whenever crossed over, on, or in the vicinity of the work. If the contractor neglects or fails to promptly make said repairs or make good of said destruction, the Corporation may make any and all necessary repairs to the satisfaction of the property owner and the Contractor agrees to promptly reimburse the Corporation the amount of its incurred cost and expenses.

6.9 The contractor shall inform the Rhode Island Energy's Forestry representative of their intent to start work at least two weeks prior to the start of any action on a feeder.

6.10 The Contractor shall implement and provide the required training and certification programs necessary to provide fully qualified Line Clearance Tree Trimmers or Line Clearance Tree Trimmer Trainees. A single Foreman may supervise multiple bucket trucks on the same project. In that case however, the minimum qualifications for the "lead" person on each of the other trucks shall be a certified qualified Line Clearance Tree Trimmer. At least one other employee on the truck shall be at least a qualifying Line Clearance Tree Trimmer Trainee, in accordance with all applicable OSHA requirements.

6.11 The Contractor shall submit a weekly time report to the Rhode Island Energy's Forestry representative, indicating the labor and equipment assigned to the project, amountof work accomplished, quantities and location of herbicide applications and location of the work.

6.12 The Contractor shall provide a monthly summary report to Distribution Forestry, identifying crew staffing and equipment by area as of the first of each month, to be submitted by the 5th of each month or the following Monday should the 5th fall on the weekend. The report shall also identify work type (e.g., such as hourly, new construction, danger trees, mowing; lump sum or unit price) by project, percentage complete for all fixed price projects, and anticipated completion dates.

6.13 The Contractor shall provide a monthly OSHA injury summary report in a format supplied by Rhode Island Energy for the previous month, no later that the 10th of the month or the following Monday should the 10th fall on the weekend. The data in the report shall be separated by state as well as reported for the overall ContractorCompany for any and all United States operations.

6.14 By April 10th of each year, the contractor shall provide a list of employees and Aerial lifts that could reasonably be expected to work on RI Energy's property to Distribution Forestry. This listing shall include:

Employees:

- identify the current pay classification of each employee, together with their union certification level,
- the date of their progression to their current pay level,
- the dates each employee completed their required OSHA safety and other training, or retraining, including any annual refreshers,
- the date each employee last demonstrated their tree rescue and climbing proficiency
- the date each employee completed first aid and CPR training,
- identify each certified pesticide applicator and their certification number.

Aerial Lifts:

- The truck number and date of dielectric testing
- The next scheduled dielectric test date

6.15 The contractor shall provide a unit cost per tree for the removal of potential hazard trees from the three phase portions of the circuit, as well as “high risk target” hazard trees from the single-phase portions. See the attached Addendum # 1, Hazard Tree Removal, Unit Price Schedule to be bid separately from the fixed price project. Rhode Island Energy reserves the right to award**,** in whole or in part, the removal of hazard trees for each bid package on the basis of these unit price costs, or to do the work at the contractor’s current hourly rates.

VII. Acceptance of Work

7.1 At appropriate intervals, the Contractor shall report and review the work completed to date with Rhode Island Energy’s Forestry representative. The Contractor may then invoice for the percentage of the work completed and approved by Rhode Island Energy.

7.2 Near completion of the work, the Contractor shall notify the Rhode Island Energy Forestry representative that the entire project has been reviewed by the contractor’s supervision and is now ready for inspection. Upon review and acceptance of all required work including the resolution of any and all required corrective actions as well as any outstanding damage claims, the RI Energy Forestry representative will give the contractor permission to submit a final invoice for payment.

7.2.1 Traffic detail costs associated with re-work or corrective action shall be borne by the Contractor.

7.2.2 Police detail costs for any work not completed by the end of the fiscal year (March 31st) shall be borne by the Contractor. Rhode Island Energy has the discretion to make allowances for circumstances outside of the Contractor’s control. (Storms, requested outages, etc.)

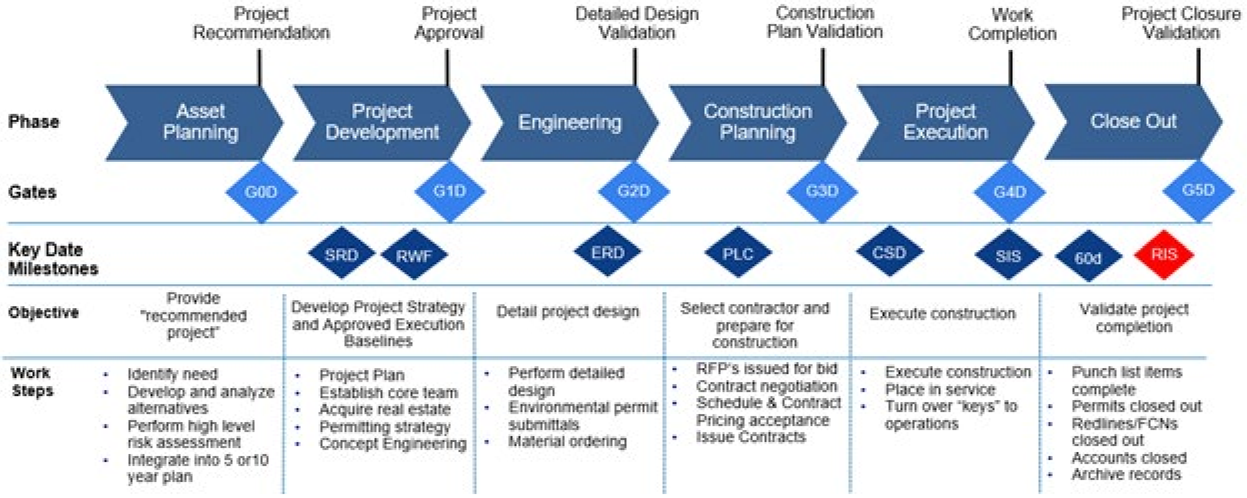
7.3 The contractor shall understand, per their signed Master Purchase order with Rhode Island Energy that time is of the essence with respect to the performance of this work. The contractor shall take all appropriate actions necessary to complete the work on schedule. Those actions shall include among other things, the use of overtime,the use of supplemental labor crew resources from outside areas, and the use of subcontractors, not withstanding the RI Energy requirement for advanced approval of all subcontractors. All actions employed by the

8 The contractor shall understand, per their signed Master Purchase order with Rhode Island Energy that time is of the essence with respect to the performance of this work. The contractor shall take all appropriate actions necessary to complete the work on schedule. Those actions shall include among other things, the use of overtime,the use of supplemental labor crew resources from outside areas, and the use of subcontractors, not withstanding the RI Energy requirement for advanced approval of all subcontractors. All actions employed by the to complete their schedule are at their cost and shall not affect the lump sum contract amount. In the event ofextenuating circumstances defined by RI Energy, the company reserves the right to extend project completion dates.

Attachments 1-35-3 & 1-35-4

Please be advised that Attachments 1-35-3 & 1-35-4 are very voluminous and are very large electronic files. The Company is providing these files separately via electronic link.

Prepared by or under the supervision of: Ryan Constable



	Project Recommendation	Project Approval	Detailed Design Validation	Construction Plan Validation	Work Completion	Project Closure Validation
Phase	Asset Planning	Project Development	Engineering	Construction Planning	Project Execution	Close Out
Gates	G0D	G1D	G2D	G3D	G4D	G5D
Key Date Milestones		SRD RWF	ERD	PLC	CSD SIS	60d RIS
Objective	Provide "recommended project"	Develop Project Strategy and Approved Execution Baselines	Detail project design	Select contractor and prepare for construction	Execute construction	Validate project completion
Work Steps	• Identify need • Develop and analyze alternatives • Perform high level risk assessment • Integrate into 5 or10 year plan	• Project Plan • Establish core team • Acquire real estate • Permitting strategy • Concept Engineering	• Perform detailed design • Environmental permit submittals • Material ordering	• RFP's issued for bid • Contract negotiation • Schedule & Contract Pricing acceptance • Issue Contracts	• Execute construction • Place in service • Turn over "keys" to operations	• Punch list items complete • Permits closed out • Redlines/FCNs closed out • Accounts closed • Archive records

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DRAFT: Rhode Island Energy Delegation of Authority and Sanctioning Framework

Business Use

Threshold	Up to $5M	>$5M up to $50M	>$50M
Frequency	Ongoing	Ongoing	As Required
Final Approver	Supervisor-$50K Manager-$1M Sr. Manager/Director-$30M	Sr. Manager/Director-$30M Sr. Director - $40M President - $50M	Leadership Committee: President RIE, COO, CEO
Documentation (Power Plan)	Fact Sheet	Sanction Paper	Sanction Paper

General Guidelines

- All investments up to $5M will be submitted for Electronic DoA within Power Plan.
    - Documents Tab: Attach Fact Sheet
    - Authorization Tab: Auto Populate based on DOA Limits
- Investments greater than > $5M up to $50M will be submitted for Electronic DoA within Power Plan.
    - Project Author/Sponsor is required to consult and gain approval of the applicable supporters, prior to routing for DoA in Power Plan.
    - Documents Tab: Attach Sanction Paper
    - Authorization Tab: Select DOA Approval – Manual, select appropriate approver based on DOA Limits
- Investments > $50m require completion of a sanction paper and sent to Leadership Committee
    - Project Sponsor is required to consult and gain approval of the applicable supporters, prior to routing for DoA in Power Plan.
    - Route sanction paper for approval to Leadership Committee
    - Documents Tab: Attach Sanction Paper
    - Authorization Tab: Select DOA Approval – Manual, select appropriate approver based on DOA Limits
- Project Sponsor shall utilize an Electronic RIE Sanction SharePoint site during development.
- Sanction and Fact Sheet papers shall be posted to RIE Sanction SharePoint site.

Re-Sanction Process/Closeout Process

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Re-sanction Guideline

- Sanction estimate
- Re-sanction when you exceed estimate accuracy

Closeout Process

- Document Lessons Learned
- Close out Funding Projects and Work Orders per Power Plan requirements

Sharepoint Folder Structure

1. Draft Folder
    1. Fact Sheet Folder <$5m
        1. Project Folder
            1. Draft Fact Sheet
            2. Project Documents
        2. Archive Folder – move after approval
    2. Sanction Paper Folder >$5m
        1. Project Folder
            1. Draft Sanction Paper
            2. Project Documents
        2. Archive Folder – move after approval
2. Final Folder
    1. Fact Sheet Folder <$5m
        1. Final Fact Sheet
    2. Sanction Paper Folder >$5m
        1. Final Sanction Paper (attachments should be a PDF within File)

Fact Sheet/Sanction Paper Naming Convention

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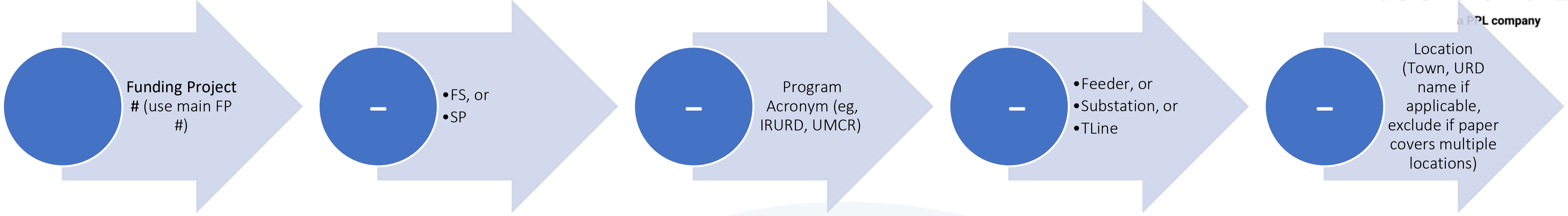
Program Naming Convention



Funding Project # (use main FP #)

–

- FS, or
- SP

–

Program Acronym (eg, IRURD, UMCR)

–

- Feeder, or
- Substation, or
- TLine

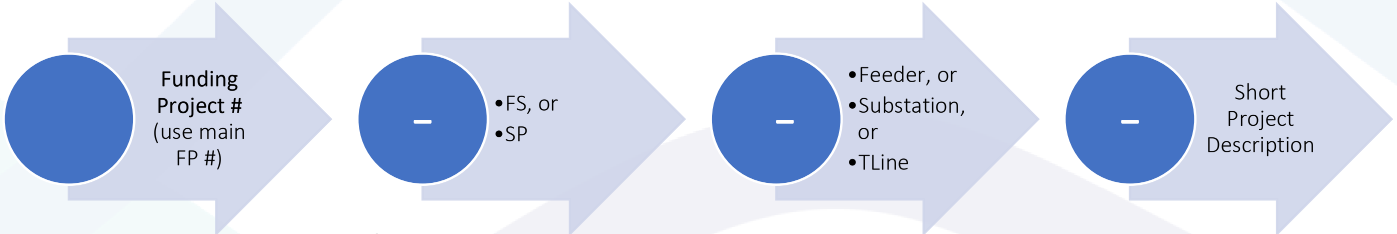
–

Location (Town, URD name if applicable, exclude if paper covers multiple locations)

Example #1: C0XXXX-SP-UMCR-1144/1109

Example #2: C0XXXX-FS-IRUD-127W40-Woonsocket_Spring_Estates

Specific Naming Convention



Funding Project # (use main FP #)

–

- FS, or
- SP

–

- Feeder, or
- Substation, or
- TLine

–

Short Project Description

Example #1: C0XXXX-SP-Tiverton_Sub_Expansion

Example #2: C0XXXX-FS-Division_ST_61F2_Reconductoring

Division 1-36

Request:

Provide the RIE Grid Modernization Plan. Provide all assessment data, evaluations, justification documents, assumptions, workpapers, studies, and any information relied upon to develop the GMP and associated budget in the FY24 ISR Plan. Provide data in executable format.

Response:

Rhode Island Energy's Grid Modernization Plan ("GMP") is being finalized and will be provided when it is complete. The Company currently plans to file the GMP with the Public Utilities Commission by the end of December 2022. As discussed with the AMF/GMP Subcommittee of the Power Sector Transformation ("PST") Advisory Group on November 9, 2022, the Company is using well-established Benefit-Cost Analysis ("BCA") methodologies and input assumptions. The BCA that will be used in the GMP will justify the Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan foundational investments and is consistent with the Public Utilities Commission's Docket 4600 Framework. The GMP will include the study assumptions, projections, and analysis to support the conclusions that the GMP foundational investments included in the FY 2024 Electric ISR Plan are justified and urgently needed.

The presentations provided by the Company to the PST Advisory Group are included as Attachment DIV 1-36-1 through Attachment DIV 1-36-4. These presentations provide preliminary insight into the GMP studies, evaluations, and justifications in advance of the formal GMP filing.

Attachment DIV 1-36-1, presented July 2022, includes details on the GMP study approach and forecast inputs (slides 24-33).

Attachment DIV 1-36-2, presented August 2022, includes preliminary study results, reference feeder details, and software functionality (slides 31-66).

Attachment DIV 1-36-3, presented October 2022, was a demonstration on the CYME analysis used for the GMP effort.

Attachment DIV 1-36-4, presented November 2022, includes an update on study results, functionality roadmaps, and initial benefit-cost analysis results.

Prepared by or under the supervision of: Wanda Reder

Advanced Meter Functionality and Grid Modernization Plan Overview and Stakeholder Outreach

Power Sector Transformation – July 14, 2022

Agenda

9:30 – 9:45	Introductions, Objectives and Background
9:45 – 10:00	The Current State and PPL Insights
10:00 – 10:10	Potential Solutions and Enabled Functionalities
10:10 – 10:25	AMF Technology and Project Overview
10:25 – 10:35	Functionalities Roadmap
10:40 – 10:50	Implementation Plan
10:50 – 11:00	AMF Costs Review
11:00 – 11:15	Break
11:15 – 11:30	GMP Study Scope and Approach
11:30 – 11:45	DER Forecast
11:45 – 12:00	Next Steps

Objectives

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- AMF Business Plan
  - Introduce the RIE AMF Business Plan
  - Highlight advantages from PPL background and experience
  - Describe why full-scale AMF system
  - Review AMF implementation and functionality
  - Review AMF costs
- GMP Business Plan
  - Introduce the GMP study scope and approach
  - Review and agree upon the DER forecast

Ground Rules:

- Ask questions and provide feedback as we go
- Raise hand and state name when asking questions
- One conversation at a time
- Timekeeper to monitor discussion and align to agenda
- Topics and questions scheduled for future discussion will be saved in the Parking Lot

Background

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- PPL Corporation acquired The Narragansett Electric Company on May 25, 2022 and rebranded the utility as Rhode Island Energy (RIE).

- Converging drivers are creating the need to act:

  1. **Operational**: Approximately 60% of meters are at the end of their design life
  2. **Modernized System:** Increased visibility/control (planning, integration, management)
  3. **Clean Energy:** Net-zero greenhouse gas emissions by 2050,100% renewables by 2033
  4. **Customer Expectations:** Manage energy usage, improved reliability and superior customer experience

- Plan to file an advanced metering functionality (AMF) business case in September 2022 and a GMP business case by the end of 2022

- Seeking Power Sector Transformation (PST) Advisory feedback in anticipation of making the AMF and GMP filings

RI PST Advisory Collaboration

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AMF – Advanced Metering Functionality
GMP – Grid Modernization Plan
BCA – Benefit-Cost Analysis

🟦	Initial alignment meeting with RI Division and OER
🟦	PST Advisory Sub-Committee Meeting AMF
🟨	PST Advisory Sub-Committee Meeting GMP

★ September 2022
AMF Targeted Filing Date

★ December 2022
GMP Targeted Filing Date

PST Advisory AMF & GMP Subcommittee Meetings and Preliminary Agendas

Stakeholder Collaboration (i.e., Subcommittee meetings and discussions)

Obtain Feedback and Seek Alignment on Proposals and Approaches

Review Initial, Refined and Final Proposals

Jun 21, 2022

- **RI Division and OER Meeting**
- Introductions
- Proposed timeline
- Preliminary agenda for PST meetings
- AMF Introduction and overview of key areas
- GMP Introduction and coordination

July 14, 2022

- **PST Advisory Meeting**
- Introductions
- PPL Background and Experience
- Full Scale Enabling Platform
- Detailed Deployment Plan
- Functionality Timing
- ASA coverage
- AMF cost review
- GMP study scope and approach
- GMP forecast analysis

Aug 2, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Customer Engagement Plan
- AMF Opt-out
- AMF Customer value streams
- AMF Auto-notification
- AMF Benefits

Aug 16, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Data access, privacy, governance
- AMF Cyber Security
- AMF Cost and Benefit Recap
- Cost Recovery and Revenue Requirements
- GMP scenario analysis
- GMP solution development
- GMP ISR Coordination plans

September 2022 ★

- **File AMF**
- AMF Includes Business Case, Testimonies and BCA
- Coordinate with GMP execution plan and BCA

w/o Oct 20, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- GMP Alternative recommendation
- GMP BCA review

December 2022 ★

- **File GMP**
- GMP Includes Business Case, Testimonies and BCA
- Coordinate with ISR and AMF details

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Advanced Meter Functionality (AMF) Business Plan

AMF Overview

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- Replace ~525,000 electric AMR meters with AMF meters over a 3 ½ year deployment
- Design and build a fixed, secure IP-based radio frequency (RF) mesh network
- Back-office IT systems are developed that harmonize with TSA developments providing functionality to achieve objectives of customers, the utility, and clean energy
- Anticipated outcomes:
  1. Additional customer capabilities to manage their energy usage
  2. A technologically-advanced, state-of-the-art metering infrastructure
  3. The requisite tools and technology required to achieve clean energy goals
  4. An enabling platform to position for future grid modernization and gas AMF
- Strong Benefit/Cost ratio: ~3, 4 and 5 for Utility, Customer and Societal respectively

Current State of RIE Electric Meters

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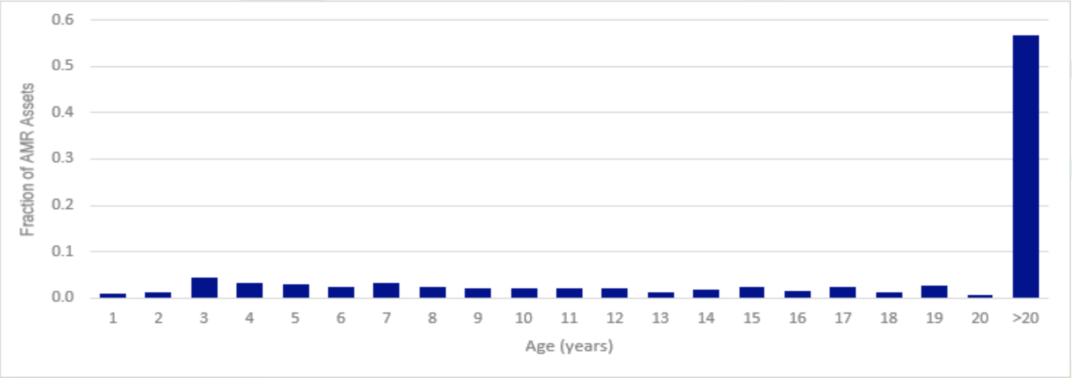
- 528,848 electric meters
- Two types of AMR meters with modules
- Read with drive-by technology
- Collects <u>one</u> billing read per month
- ~60% are at end of design life

Electro-mechanical Meter

Solid State Meter

Age of Meter Assets



Technology is old, does not provide required functionality and needs to be replaced

The Current State and PPL Insights

GMP and AMF for Operational Impacts of Clean Energy

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Context

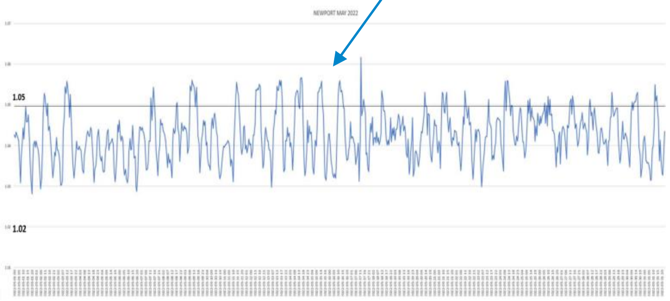
- DER forecasted penetration is needed for Clean Energy requirements
- Society is increasingly dependent on a reliable electric supply

Operational Impact (lack of visibility hides existing issues)

- Reliability is trending worse. Reliability and safety risk is building due to lack of situational awareness and challenges to manage the grid
- Increased variability of load and voltage, creating violations
- Increasing system complexity and multi-directional power flow
- Greater operational uncertainty
- Greater dependency on local generation to balance with load
- Increased system load due to beneficial electrification
- Emerging markets and rate designs will require new functionality

RIE Operational Challenge

**Voltage repeatedly exceeds 1.05 per unit operating target*



Solar DER nominal voltage output in RIE Newport Region - May 2022

**Required to maintain ±5% of nominal voltage ie 0.95 to 1.05 per unit voltage.*

Investment Needed

- AMF and GMP needed to provide visibility, awareness and added system monitoring and control for reliable and safe operations with increasing DERs that are contributing towards Act on Climate

The Current State and PPL Insights

Our AMF Approach

- Presents the need to replace the AMR system with a proposal having costs and benefits over 20-years
- Utilized National Grid Updated Business Case (Docket 5113) as a basis
  - Interviewed National Grid contributors
  - Modified NG BCA
  - Addresses Amended Settlement Agreement (ASA) items
- Factored in PPL AMF deployment experience, costs, business impacts, processes and systems
- Incorporated updated pricing from suppliers
- Updated BCA assumptions with current information
- Created a detailed deployment plan and system release schedule harmonized with TSA developments

RIE Considered Amended Settlement Agreement

1	A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed customer engagement plan
2	An updated AMF deployment schedule with a BCA (using Societal Cost Test) for different meter deployment periods
3	Revenue Requirement for AMF deployment
4	Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF
5	A proposal to allocate AMF costs among rate classifications
6	Assumptions upon which a proposal for Time-Varying rates will be based
7	A Data Governance Plan regarding customer, NPP, and third-party access to system and customer data in place with access to quality customer and billing data, along with appropriate privacy and security protections
8	Updated costs for AMF deployment based on information gained from procurement efforts
9	Transparent, updated benefit cost analysis that fully incorporates the Docket 4600 framework
10	Investigation of alternative business models and ownership models
11	Analysis of data latency
12	Deployment details
13	Role of non-regulated power producers, including articles to share customer information and customer engagement
14	Ownership model for assets and telecom
15	Detailed AMF functionalities, how RI will achieve these functionalities, and a timeline for when those functionalities are available
16	Identification of the most cost-effective way to achieve the functionalities, and how the functionalities align to policy objectives
17	Explanation of whether the realization of those functionalities align to policy objectives will require additional future work and costs over 20 years
18	Identification of what functionalities the AMF will achieve that are part of the grid modernization plan and which are in addition to the Grid Modernization Plan
19	Identification of which functionalities are dependent on full-scale roll out instead of a targeted roll out
20	Business case based on both a RI-only scenario and RI/New York scenario
21	A business case based on the length (duration) of meter deployment
22	Identification of the critically linked parts of grid modernization and AMF
23	Identification of whether the AMF solution would allow for proper net metering according to the tariff

The Current State and PPL Insights

RIE Benefits from PPL AMF Insights

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PPL Full-Scale Automated Meter Reading Experience includes several million meters over the last two decades:

- PPL First Generation in PA: 2002 – 2004
- PPL Second Generation in PA: 2015 – 2020
- LG&E KU Full Scale Launch in KY: Oct. 20221 - 2026

PPL Offers Many Insights:

- AMF Meter Implementation
- Back-Office Systems Deployment and Integration
- Communication Network Design/Implementation
- People, Process, and Tools
- DER Management and Monitoring
- Integration with grid modernization

RIE Benefits:

- Implementation Cost Efficiencies
- Functionality Efficiencies
- Lessons Learned and Best Practices
- Vendor Relations and Purchasing Power
- Operational Efficiencies
- Shared Network Services
- Analytics

Functionality Assessment of Metering Solutions

National Grid developed for their Updated Business Plan

Recommend **<u>Full-Scale</u>** AMF Solution:

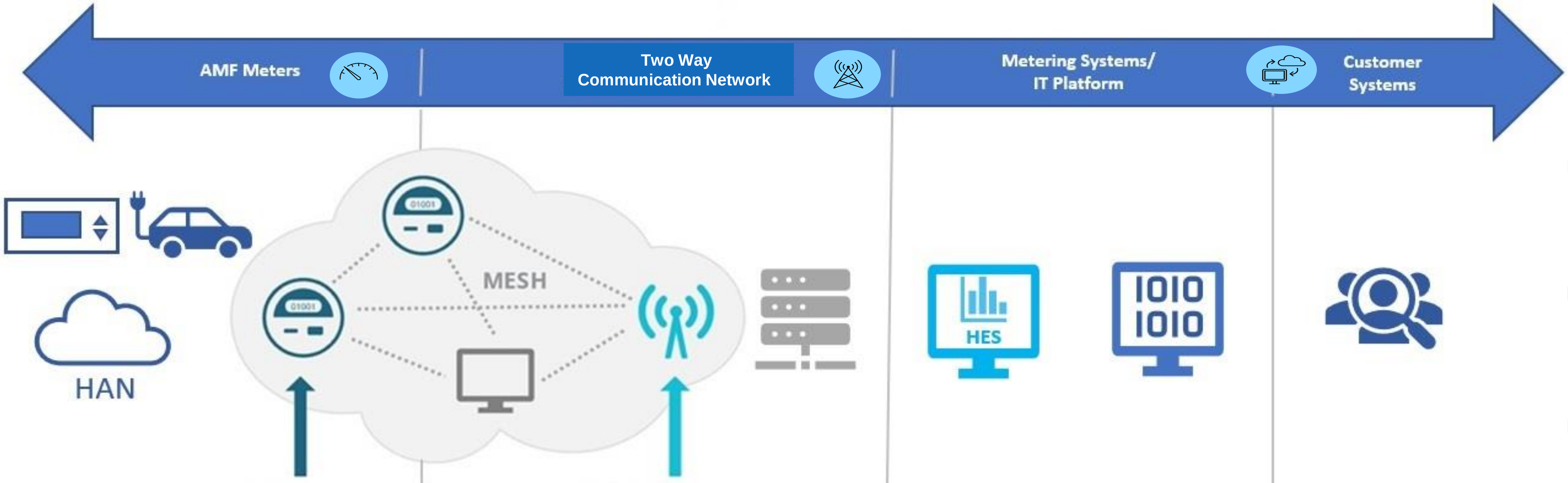
- ✓ The only fit-for purpose solution
- ✓ Supports all enhanced functionalities
- ✓ Provides capability to meet multi-pronged objectives

	AMF Functionality / Use Case	Complete Metering Solutions				Complementary Customer and Grid Technologies		
		Current AMR	Targeted Enhanced AMR (Opt In)	Targeted AMF*	Full-Scale AMF	End User Solutions*	Transformer level Sensors	Pole Top Sensors
Customer-Facing	CP – Near Real Time Customer Data Access	○	○	●	●	●	○	○
	CP – Customer Energy Insights	◑	◑	●	●	◑	○	◑
	CP – Bill Alerts	○	○	●	●	◑	○	◑
	CP – Load Disaggregation	○	○	●	●	●	○	○
	CP – Green Button Connect	○	○	●	●	○	○	◔
	Integrates with In-Home Technologies	○	○	●	●	●	○	○
	Time Varying Rates, Customer and DER	○	◔	●	●	○	○	○
	Remote Interval Meter Reading	○	○	●	●	○	○	○
	Remote Meter Configuration	○	○	●	●	○	○	○
	Remote Meter Investigation	○	○	●	●	○	○	○
	Remote Electric Connect and Disconnect	○	○	●	●	○	○	○
	Theft Detection	◔	◔	◕	●	○	○	◔
Grid-Facing	Voltage Measurement – VVO / CVR	○	○	◔	●	○	◑	○
	Outage Detection and Notification	○	○	◔	●	○	◑	◔
	Time Varying Rates – Load Shift	○	○	◕	●	○	○	◔
	Load & Voltage Data – Situational Awareness	○	○	◔	●	○	◑	◔

** Included combination of high-resolution home sensors with in-home technology packages and no CP integration, *** Assumes integration with utility platforms services (e.g. billing)

Potential Solutions and Enabled Functionalities

Full Scale AMF Technology Elements



Behind the Meter Devices

Creating customer visibility to Home Area Network (HAN) technologies via Wi-Fi including real time consumption, DERs, EVs, etc.

AMF Meters

- Bi-directional
- Residential
- Commercial
- Industrial

Radio Frequency Mesh Network

Communication between meters, routers, mesh extenders, and Gateways

Network Backhaul

Infrastructure between Gateways and utility head-end: a.k.a. WAN

Collection of necessary networking components that enable secure communication from meters and routers to the head-end system

AMF Head End System

Collects meter data, identifies and collects gap data, allows for meter management and monitoring

Meter Data Management System(MDMS)

VEE (Validation, Estimation, and Editing) of meter data

Provides 'Bill Ready' customer data

Customer Service System(CSS)

Customer billing data

Customer Portal

- Energy Insights
- Energy Alerts
- Green Button

AMF Meters

- Most critical component for enabling the benefits
- Reads customer data at 15-minute intervals
- Can support TOU/TVR leading to stronger customer engagement, better energy management
- Two-way communication provides new customer and grid-facing functionality for remote operations
- Enables new and needed customer-facing and grid-facing functionality
- Hardware features:
  - Remote connect/disconnect
  - Multiple registers (kWh (real), KVAR (reactive), voltage)
  - Integrated Wi-Fi
  - Temperature Sensor
  - Arc Sensor
  - Accelerometer
  - Cover Removal Switch
  - Precision Network Timing

AMF Technology and Project Overview

Two-Way Communication Network

RF Mesh Communication Network

- Provides state-of-the-art two-way communications with the meters
- Solution includes a communication network that is IP-based
- Applies radio (RF) using peer-to-peer communications to create a mesh
- Analysis performed to minimized number of ‘hops’ each endpoint needs to get data back to the HES
- Security is inherent in the design to safely transmit data
- Network is self-healing, featuring dynamic routing messages that automatically adjust for changes
- Design accounts for scalability and forecasted end-points

Backhaul

- Will utilize a cellular network as backhaul unless RIE fiber is available, in which case it will be used.
- Data will be encrypted at transit at the networking layers on the devices

Substation Network Equipment

Pole-Mounted Network Equipment

Router

Network Gateway

AMF Technology and Project Overview

Systems

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Head End System (HES)

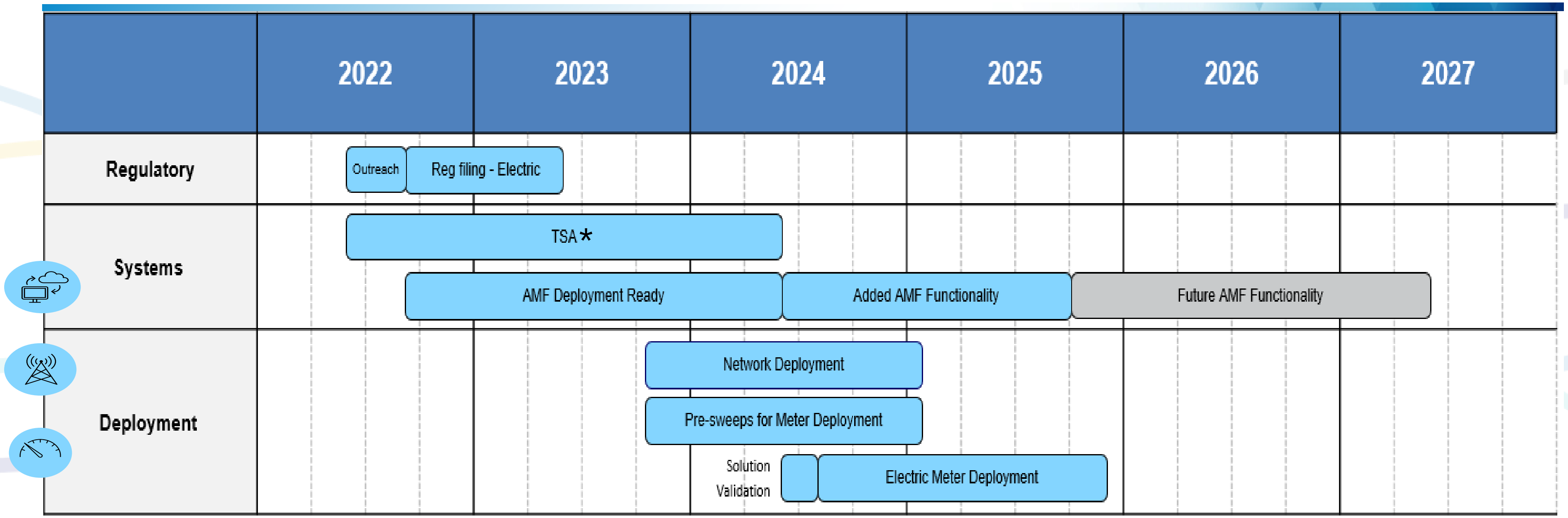
- HES is the centralized data collection solution for all meter information coming from the Network Gateways through the Backhaul
- Provides the tools to manage and monitor the advanced capabilities of the AMF meters
- HES can send commands such as remote connects/disconnects, and over-the-air (OTA) updates
- Ability to communicate through the HES to the meter to provide utility visibility and enables functionality

Meter Data Management System (MDMS)

- HES delivers data to MDMS for data validation and pre-billing
- Will be sourced for various customer enablement programs such as the Customer Portal, the Supplier Portal, and providing Green Button Connect data.
- Will populate many distribution operations systems to enable better near real-time visibility of the system and to enable more efficient management of the grid

AMF Deployment

AMF Deployment Schedule (3 ½ Years)



* TSA is the "Transition Service Agreement" where National Grid operates and maintains its back-office systems for RIE customers for up to <u>two years</u> after PPL closed on the transaction to acquire Narragansett Electric Company.

Implementation Plan

AMF Functionality Roadmap

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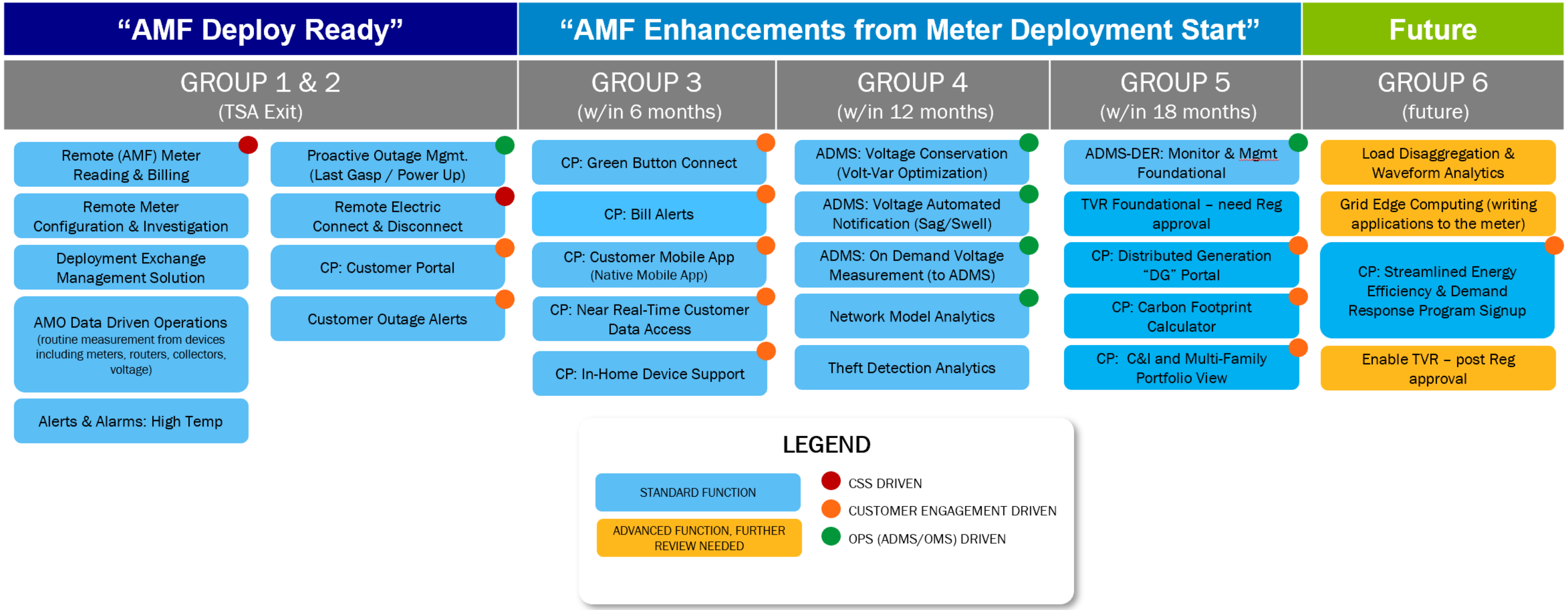


"AMF Deploy Ready"		"AMF Enhancements from Meter Deployment Start"			Future
GROUP 1 & 2 (TSA Exit)		GROUP 3 (w/in 6 months)	GROUP 4 (w/in 12 months)	GROUP 5 (w/in 18 months)	GROUP 6 (future)
🔴 Remote (AMF) Meter Reading & Billing	🟢 Proactive Outage Mgmt. (Last Gasp / Power Up)	🟠 CP: Green Button Connect	🟢 ADMS: Voltage Conservation (Volt-Var Optimization)	🟢 ADMS-DER: Monitor & Mgmt Foundational	🟨 Load Disaggregation & Waveform Analytics
Remote Meter Configuration & Investigation	🔴 Remote Electric Connect & Disconnect	🟠 CP: Bill Alerts	🟢 ADMS: Voltage Automated Notification (Sag/Swell)	TVR Foundational – need Reg approval	🟨 Grid Edge Computing (writing applications to the meter)
Deployment Exchange Management Solution	🟠 CP: Customer Portal	🟠 CP: Customer Mobile App (Native Mobile App)	🟢 ADMS: On Demand Voltage Measurement (to ADMS)	🟠 CP: Distributed Generation "DG" Portal	🟠 CP: Streamlined Energy Efficiency & Demand Response Program Signup
AMO Data Driven Operations (routine measurement from devices including meters, routers, collectors, voltage)	🟠 Customer Outage Alerts	🟠 CP: Near Real-Time Customer Data Access	🟢 Network Model Analytics	🟠 CP: Carbon Footprint Calculator	🟨 Enable TVR – post Reg approval
Alerts & Alarms: High Temp		🟠 CP: In-Home Device Support	Theft Detection Analytics	🟠 CP: C&I and Multi-Family Portfolio View	

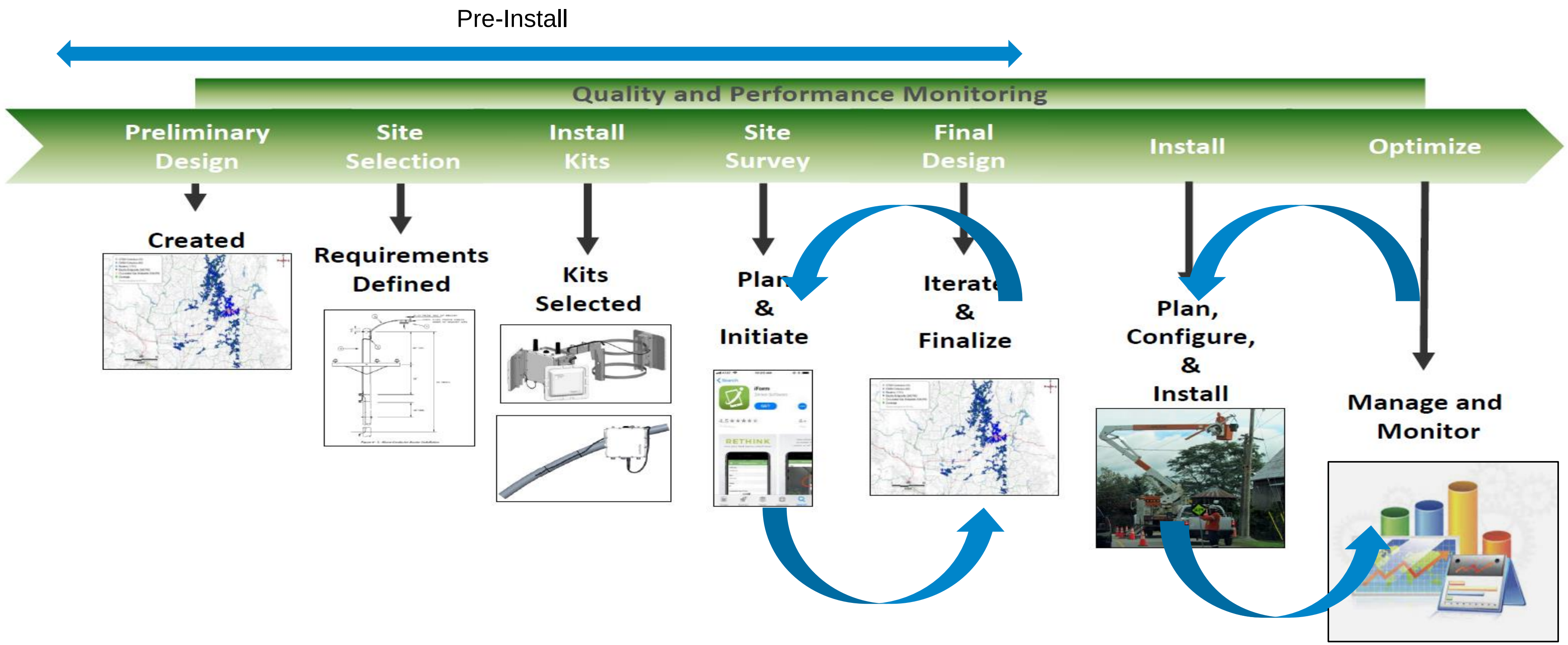
LEGEND

🟦 STANDARD FUNCTION	🔴 CSS DRIVEN
🟨 ADVANCED FUNCTION, FURTHER REVIEW NEEDED	🟠 CUSTOMER ENGAGEMENT DRIVEN
	🟢 OPS (ADMS/OMS) DRIVEN

Functionalities Roadmap

Network Staging and Deployment Process

Two-Way Communication Network Staging and Deployment



Pre-Install

Quality and Performance Monitoring

Preliminary Design → Created

Site Selection → Requirements Defined

Install Kits → Kits Selected

Site Survey → Plan & Initiate

Final Design → Iterate & Finalize

Install → Plan, Configure, & Install

Optimize → Manage and Monitor

Deployment by Sector

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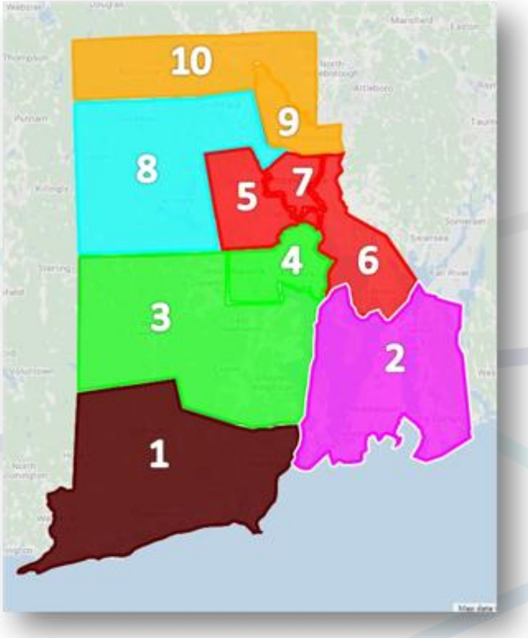
Considerations for Deployment Sector Rollout:

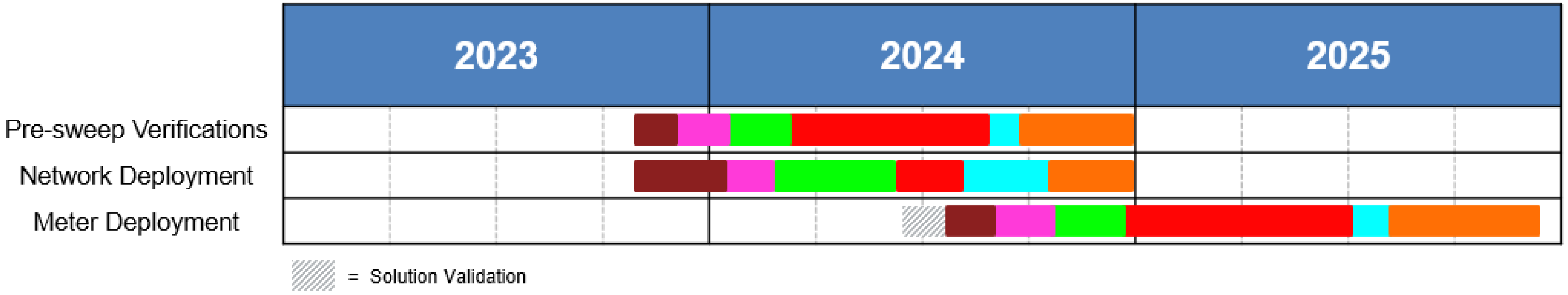
- Avoids coastal areas in the summer
- Allows time to address hard-to-access indoor meter situations
- Homogenous mix of service and meter types at the start of the project
- Avoids heavily populated areas in the initial stages to reduce complexity
- Prioritizes higher density DER areas

Deployment Sectors



Sequence No.	Sector
1	Westerly
2	Middletown
3	North Kingstown - W
4	North Kingstown - E
5	Providence -W
6	Providence - E
7	Providence
8	Chopmist
9	Lincoln - E
10	Lincoln - W

Deployment Sector Schedule



AMF Cost Review - DRAFT

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Overview

Meter

- ⊞ Hardware
- ⊞ Installs
- ⊞ Pre-Sweeps
- ⊞ Program Management
- ⊞ Repairs

Network

- ⊞ Hardware
- ⊞ Installs
- ⊞ Program Management
- ⊞ Steady State Operations

Systems

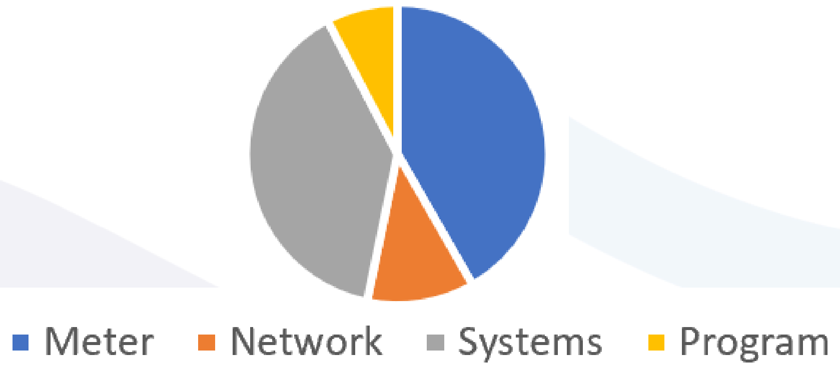
- ⊞ ADMS & OMS
- ⊞ Analytics
- ⊞ CSS
- ⊞ Customer Engagement
- ⊞ CyberSecurity
- ⊞ Deployment Exchange Mgt.
- ⊞ Grid Edge & Load Dissag.
- ⊞ Headend
- ⊞ MDMS
- ⊞ Middleware
- ⊞ Program Management
- ⊞ Steady State Operations

Program

- ⊞ Change Management
- ⊞ Program Management

AMF 20-Year Nominal Cost
$288.46M*

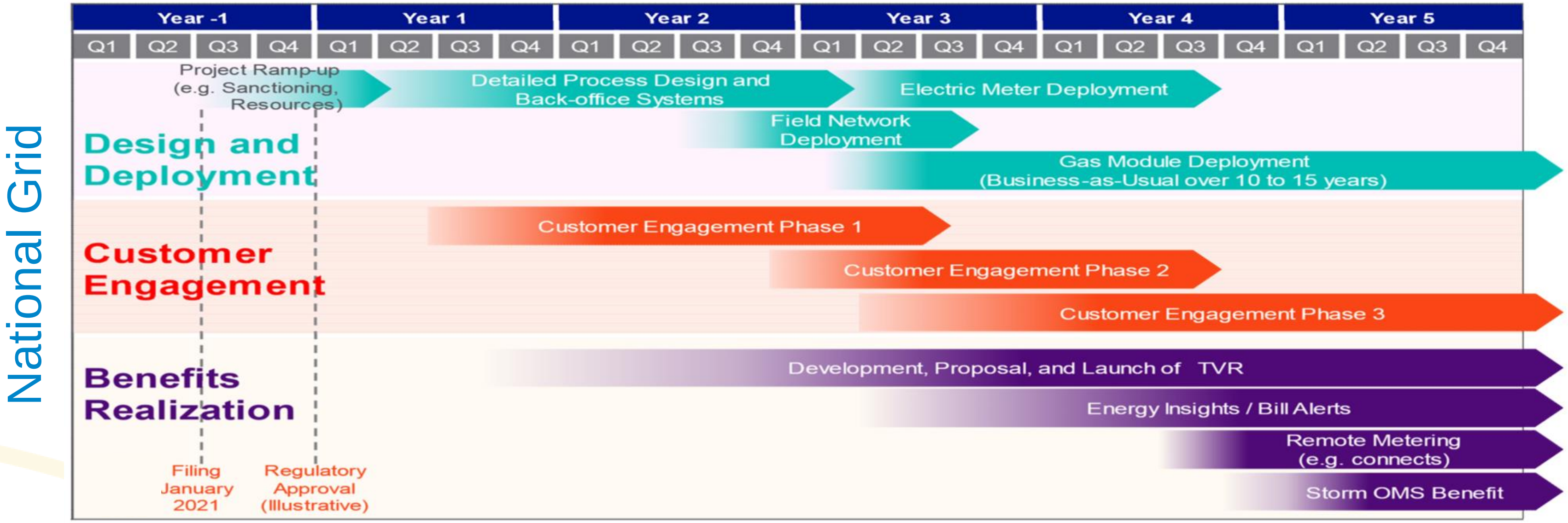
AMF 20-Year NPV
$189.99M*

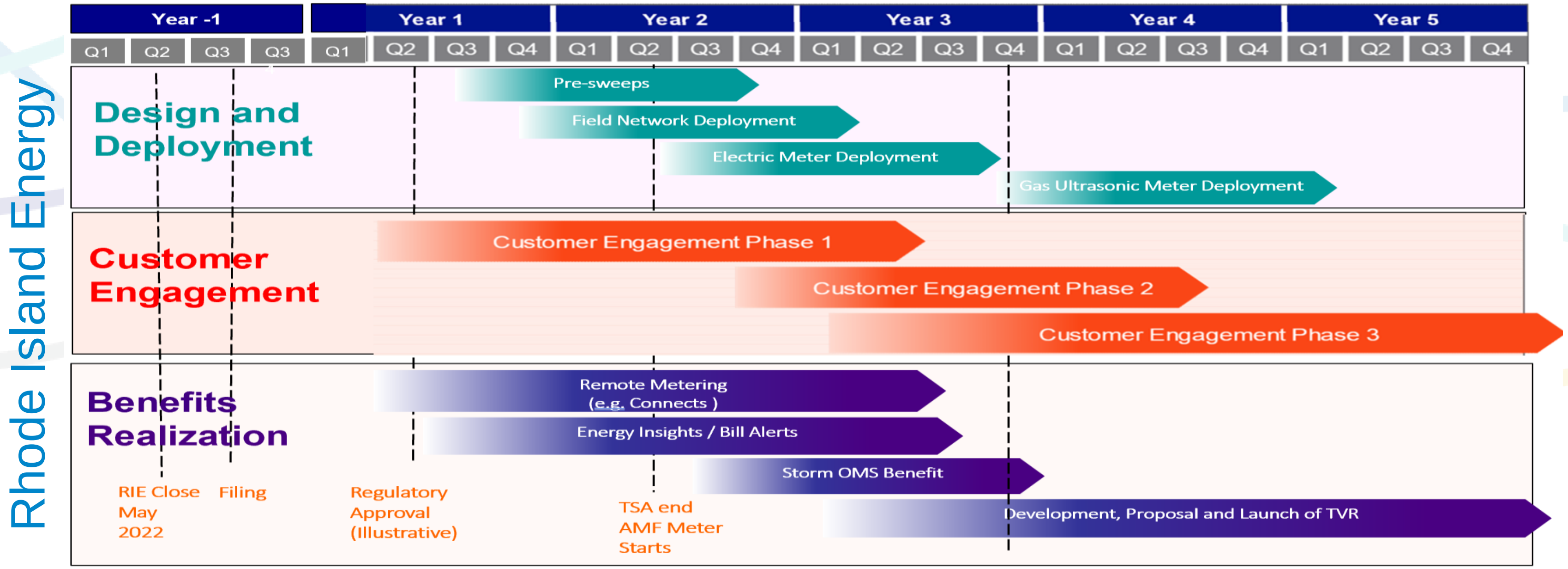


* Compared to NG of $289.35 nominal and 192.60 NPV

AMF Deployment Comparison

National Grid and Rhode Island Energy





Functionalities Roadmap

AMF Comparison: RIE and National Grid

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Similarities

- Deployment period of 3 ½ years
- Fixed IP-based RF mesh communication system
- Full-scale technical solution
- Opt-out assumption 1%
- Alternative business analysis
- Used the NG BCA framework applying Docket 4600 requirements
- Customer Engagement Plan
- Data latency assumptions
- Assumptions designed to meet clean energy goals
- TVR assumed in a separate filing

Differences

- Broader interpretation of AMF as enabling platform
- More robust, future-proofed communication system
- Cellular communications is not needed for meters
- Meter unit costs are slightly higher than the NG filing
- More functionality, sooner, leveraging prior PPL integration and experience
- Added pre-sweeps as a deployment activity
- Update meter bases where needed
- More operational savings with PPL business impacts
- Outsource assumptions
- Quantification of reduced time for outage notification and customer savings from energy insight
- Used AESC 2021 report rather than 2018 report

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Grid Modernization Plan (GMP) Business Plan

Grid Modernization Plan

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- AMF and GMP, which includes Advanced Distribution Management Software (ADMS), are foundational for an electric grid that Rhode Island Energy customers deserve – safe, reliable, affordable, and clean

- An overall Grid Modernization Plan (GMP) is being developed that will allow RIE to operate safely and reliably while supporting clean energy requirements.

- PPL has extensive experience implementing technology and automating the grid in other jurisdictions which will be leveraged to define and accelerate RIE grid modernization
    - SAIFI and customer satisfaction have significantly improved with PA deployment
    - The PPL GMP playbook and business impacts will be considered in the RIE GMP

- ADMS, provided with the PPL transaction, advances business value and will improve the BCA

GMP Approach

- RI Energy will propose the most optimal deployment plan that will provide safe, reliable operations over the study period while anticipating clean energy.
- Benefit acceleration will be possible given the availability of ADMS from the PPL Transaction
- Study will conduct a Statewide 8760 analysis inclusive of the DER forecast and recently completed area study plans
- Company forecasts will be used as a base and refined to align with Act on Climate
- Duration of the study period will extend to 2050
  - Analysis to be performed for 2030, 2040, 2050
  - Timing may be refine based on analysis results that reveal changing of system characteristics
- Aligns with AMF Filing assumptions:
  - EV Forecasts and Time Varying Rate capability
  - Alignment of interdependent functionality such as proactive outage management and VVO benefits
- IIJA and Transition Agreement linkage

GMP Analysis and Solution Development

- Analysis and Solution Development will consider a “with” & “without” GMP
- Case and Solution set to be considered:
  1. Base Forecast:
     - Traditional utility solutions no GMP
     - Refined utility solutions with GMP
  2. Low Forecast:
     - Refined traditional utility solutions with GMP
  3. High Forecast:
     - Refined traditional utility solutions with GMP
- Traditional Utility solutions will include Distribution, Sub-Transmission, Transmission Line and Substation upgrades and expansion alternatives
- GMP Solutions will include Smart Devices, ADMS, DERMS, Batteries, TVR and more

Study Process

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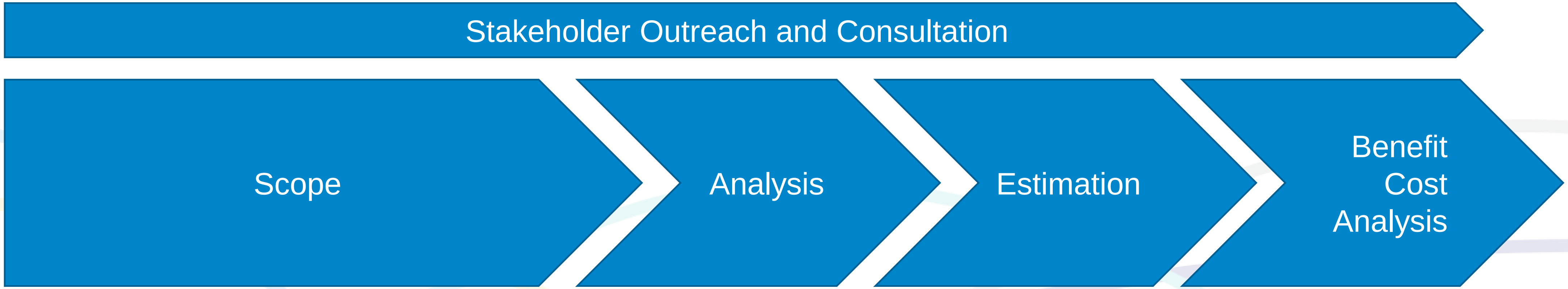


Stakeholder Outreach and Consultation

Scope

Analysis

Estimation

Benefit Cost Analysis

State-wide analysis

- ~400 feeders
- Sub-transmission modeling and testing
- Includes area study recommendations
- System-wide transmission analysis
- 8760 hour per year

Years – 2030, 2040, 2050

Cases

- No Grid Modernization – build for extremes
- Grid Modernization – manage away extremes
- Sensitivities: Low, Base, High DER forecasts
  With and without transmission consideration

Issue Identification

- Determine load and voltage issues across hours of the year
- Determine areas with degrading reliability
- Determine resiliency needs

Case Evaluation

- No GMP
- GMP

Leverage PPL proven technology

Leverage PPL experience

- Technology costs
- Installation assumptions
- Standards

Comply with Docket 4600

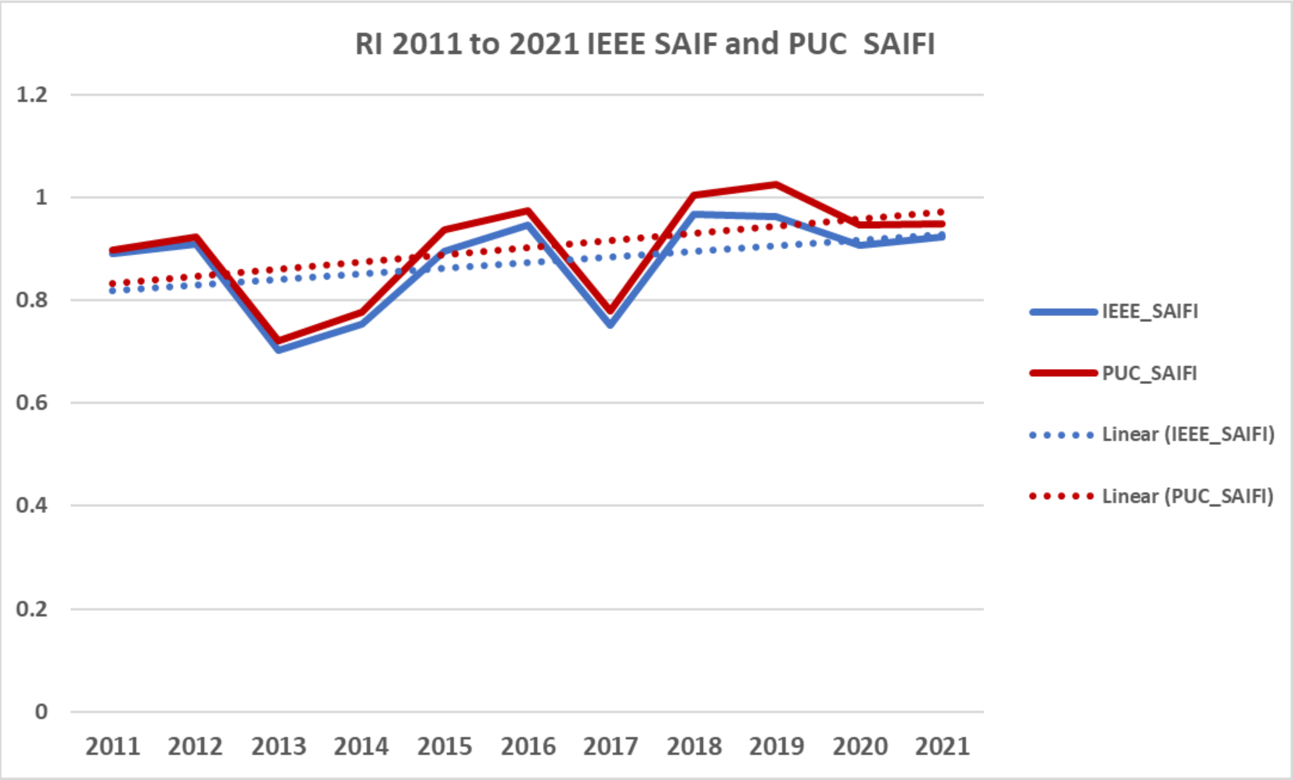
Update with PPL experience, Study and Reliability findings

2024 ISR Coordination

ADMS 'Basic' came with the acquisition

Reliability Study

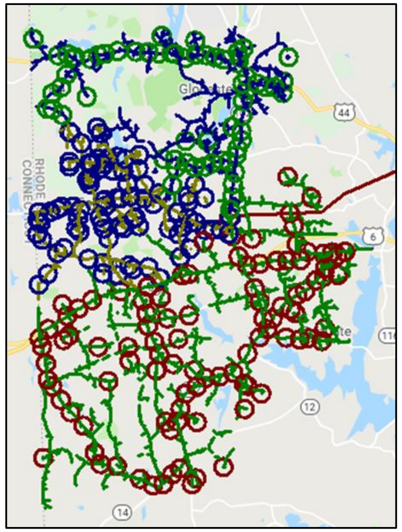
- RIE's SAIFI (interruption frequency index is increasing
- Robust data-driven approach for optimal device placement
  - outage history
  - vegetation mapping
  - construction configurations
- Leverages PPL expertise and proven value



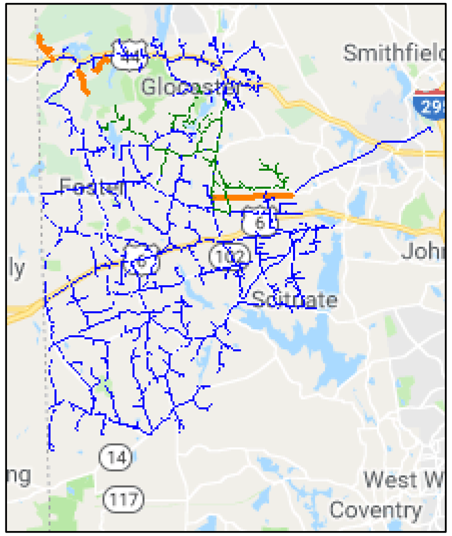
RIE reliability (SAIFI) is trending worse. Define optimal investments for improvement.

CYME Analysis

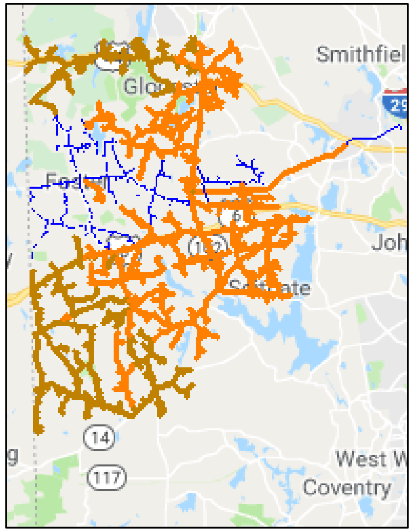
- Python script tools developed to distribute PV, EV, and EHP
  - Scattered approach, no propensity modeling
- Time Range Analysis is data intensive and time consuming
  - Time range analysis used to find key dates/times
  - Single time analysis done on key date/time



- Example: Voltage Violation – 5/25 at 12:00 pm
  - Peak load – minimal voltage issues
  - Light load - high voltage with DG – shown in **ORANGE, BROWN**



Summer Peak Load



Summer Light Load

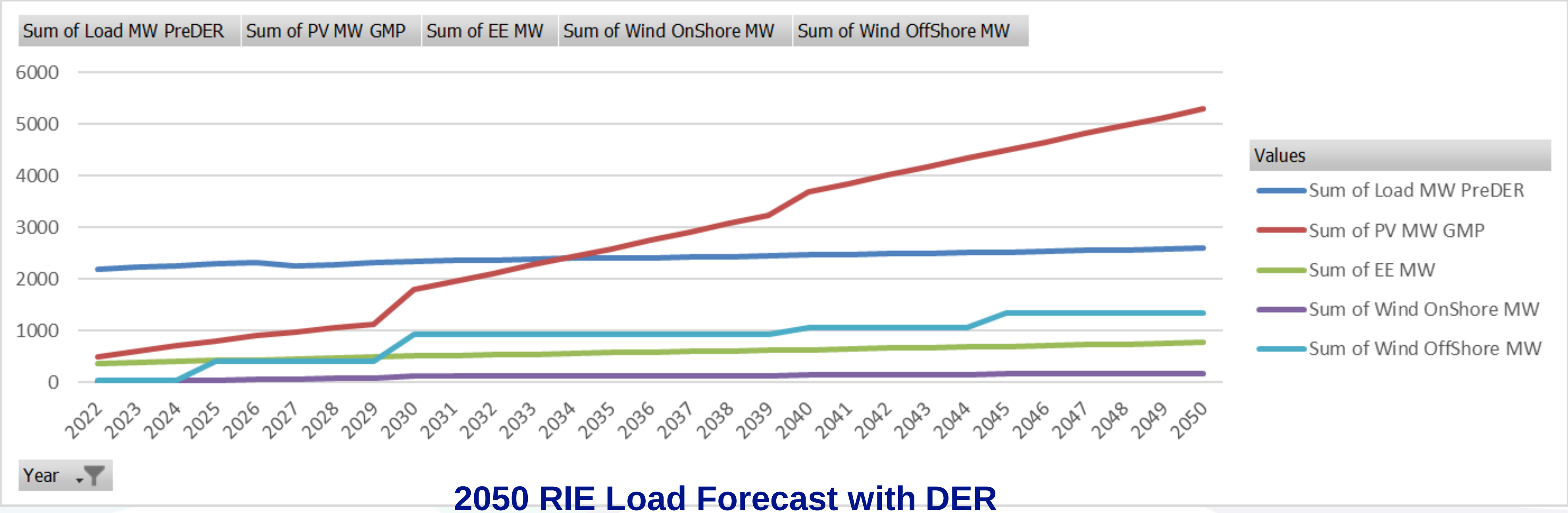
GMP Study Scope and Approach

Rhode Island's "2021 Act on Climate Bill"

- "…economy-wide enforceable targets for greenhouse gas emissions reductions as follows:
  - 10% below 1990 levels by 2020
  - 45% below 1990 levels by 2030
  - 80% below 1990 levels by 2040
  - Net-zero emissions by 2050."
  - http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-9.htm
- Revision of 2014 bill with several key changes:
  - Increased target reductions
  - Targets are mandatory and enforceable
  - Focus on equity of climate change impacts
  - More focus on workers and jobs

2050 Load Forecast with DER

- Used National Grid 2022 forecast that was issued in November 2021 as a basis
- Extended to 2050 considering ISO-NE forecast and milestone years
- Aligned with other planning and engineering efforts
- Considers Rhode Island Act on Climate Bill



2050 RIE Load Forecast with DER

DER Forecast / Impact to Peak Demand

Key DER Metrics for Milestone Study Years

	GMP DER Forecast Analysis -- Impact to Peak Demand					
	2030		2040		2050	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps, MW	0	200	5	1310	5	2825
# Heat Pumps	54,000	54,000	325,000	325,000	400,000	400,000
Solar PV, MW	0	0	0	0	0	0
Solar PV, nameplate MW	1500	1500	3400	3400	5000	5000
EV Charging, MW	70	80	805	910	1010	238
# Electric Vehicles	87,300	87,300	675,000	675,000	840,000	840,000
RIE Peak Demand, MW	1940	1415	2590	3280	2785	3855

Thoughtful DER forecast developed with sound reasoning applies to AMF and GMP

Next Steps: RIE Stakeholder Collaboration

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Upcoming Dates for PST Briefings

- Tuesday August 2nd 9:30 to noon
- Tuesday, August 16th 9:30 to noon

Appendix

Functionality Available at TSA Exit

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

Enhanced Functionality During Meter Deployment

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

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Functionalities Roadmap

Enhanced Functionality During Meter Deployment – Cont’d

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AMR or AMF Functionality	Working Definition
Network Model Analytics	MDMS functionality to support analysis of the network, identifying outlier issues for investigation (i.e. circuits missing a meter, mis-associated meters).
Theft Detection Analytics	MDMS functionality to identify outlier patterns and settlement issues that indicate potential energy theft.
CP: Distributed Generation “DG” Portal	Customer portal functionality that creates an integrated marketplace for customer research of solar PV adoption, A customer completes an online survey/audit and numerous estimates are provided for customer's review and subsequent selection of options from qualified thirdparty service providers/installers.
CP: Carbon Footprint Calculator	Customer portal functionality that creates an ability for customers to calculate carbon footprint based on usage data and actions to better manage usage.
CP: C&I and Multi-Family Portfolio View	Customer portal functionality that enables (1) a portfolio view of C&I facilities as well as properties for multifamily unit owners and managers, (2) search/sort, aggregate data and insights, assist with evaluation, measurement, and verification (“EM&V”), and (3) usage normalization on variables such as production, sq. ft., occupancy, weather.

Future Functionality

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AMR or AMF Functionality	Working Definition
CP: Streamlined Energy Efficiency & Demand Response Program Signup	Reduce program marketing spend by targeting customers who are eligible, have a higher probability of participating, and represent the highest potential load shed or shift based on specific consumption. Outreach and communications costs can be reduced by utilizing personalized channels, rather than mass marketing efforts.
Time Varying Rates (TVR) Foundational	Interval meter data with VEE integrated to billing systems and billing system functionality to support Time Variable Rate billing.
Load Disaggregation & Waveform Analytics	Provide a breakdown of electricity consumption by appliance or end-use for educational purposes and/or recommended actions to save, available through the customer portal. Meter waveform data from a representative sample of bellwether meters for general analytics use.
Grid Edge Computing (writing applications to the meter)	Metering platform for customer- and grid-facing software applications at the meter.
Enabled Time Varying Rates ("TVR")	Customer engagement and approved regulatory framework to support Time Variable Rate billing options to customers.

Acronyms

- ADMS = Advanced Distribution Management System
- AESC = Avoided Energy Supply Cost
- AMF = Advanced Meter Functionality
- AMI = Advanced Meter Infrastructure
- AMR = Automatic Meter Reading
- ASA = Amended Settlement Agreement
- ASHP = Air Source Heat Pump
- BAU = Business as Usual
- BCA = Benefit Cost Analysis
- C&I = Commercial and Industrial
- CEP = Customer Engagement Plan
- CGR = Connected Grid Router
- CO2 = Carbon Dioxide
- CP = Customer Portal
- CPP = Critical Peak Pricing
- D = Distribution
- DCFC = Direct Current Fast Charging
- DER = Distributed Energy Resource
- DERMS = Distributed Energy Resource Management System
- DG = Distributed Generation
- DLM = Dynamic Load Management
- DPAM = Distribution Planning & Asset Management
- DPL = Dayton Power and Light
- DR = Demand Response
- DRIPE = Demand Reduction Induced Price Effect
- DSCADA = Distributed Supervisory Control and Data Acquisition
- EC4 = Executive Climate Change Coordinating Council
- EE = Energy Efficiency
- EDI = Electronic Data Interchange
- EHP = Electric Heat Pump
- EIA = Energy Information Administration
- EPO = Energy Profiler Online
- ESB = Enterprise Service Bus
- EV = Electric Vehicle
- FAN = Field Area Network
- FLISR = Fault Location Isolation and Service Restoration
- GBC = Green Button Connect
- GBD = Green Button Download my data
- GHG = Greenhouse Gas
- GIS = Geographical Information Systems
- GMP = Grid Modernization Plan
- HAN = Home Area Network
- HCA = Hosting Capacity Analysis
- HES = Head End System
- HVAC = Heating, Ventilation, and Air Conditioning
- ICAP = Installed Capacity
- ICE = Interruption Cost Estimate
- IoT = Internet of Things
- IP = Internet Protocol
- ISA = Interconnection Service Agreement
- ISO NE = Independent System Operator New England
- IT = Information Technology
- KY = Kentucky
- LDV = Light Duty Vehicle
- LVA = Locational Value Analysis
- MA = Massachusetts
- MDM = Meter Data Management
- MV/LV = Medium Voltage/Low Voltage
- NEM = Net Energy Metering
- NMPC = Niagara Mohawk Power Corporation
- NPP = Non-Regulated Power Producer
- NY = New York
- NWA = Non-Wires Alternative
- OER = RI Office of Energy Resources
- OMS = Outage Management Systems
- PA = Pennsylvania
- PBR = Performance-Based Regulation
- PI Historian = Plant Information Historian
- PIM = Performance Incentive Mechanism
- PLC = Power-Line Communication
- PPL = Pennsylvania Power and Light
- PSE&G = Public Service Electric & Gas
- PSR = Platform Service Revenue
- PST = Power Sector Transformation
- PUC = Public Utilities Commission
- PV = Photovoltaic
- REC = Renewable Energy Credit
- REV = Reforming the Energy Vision
- RF = Radio Frequency
- RGGI = Regional Greenhouse Gas Initiative
- RI = Rhode Island
- RIE = Rhode Island Energy
- RMD = Residential Methane Detector
- RTP = Real Time Pricing
- RTU = Remote Terminal Unit
- SaaS = Software as a System
- SCT = Societal Cost Test
- SME = Subject Matter Expert
- ToC = Table of Contents
- TOU = Time Of Use
- TSA = Transition Service Agreement
- TVR = Time Varying Rate
- VDER = Value of Distributed Energy Resources
- VMT = Vehicle Miles Traveled
- VPP = Variable Peak Pricing
- VVO/CVR = Volt-Var Optimization/Conservation Voltage Reduction
- WACC = Weighted Average Cost of Capital

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Advanced Meter Functionality Plan
Stakeholder Outreach: Customer Engagement and Benefits

Power Sector Transformation – August 16, 2022

Agenda – PST August 16, 2022

• 9:30 – 9:40	Objectives, Recap and Feedback
• 9:40 – 9:50	PST Meeting Reflection and Follow-Up
• 9:50 – 10:50	AMF Data Governance, Cyber Security, Privacy
	AMF Benefit Cost Analysis Recap, Sensitivities, TVR
	AMF Cost Recovery and Revenue Requirements
	Reporting and Metrics
	AMF Next Steps
• 10:50 – 11:00	Break
• 11:00 – 12:00	GMP Scenario Analysis
	GMP Study Forecast Results: Northwest Region (Preliminary)
	GMP Solution Development
	GMP Software Functionality Timeline (Preliminary)
	GMP ISR Coordination and Next Steps

Objectives

- Recap results from 8-2-2022 meeting
- Discuss and solicit feedback
- Review remaining aspects for AMF Business Plan to solicit input before filing
- Begin reviewing GMP preliminary findings and solutions
- Align on ISR Coordination for GMP
- Next Steps

Ground Rules:

- Ask questions and provide feedback as we go
- Raise hand and state name when asking questions
- One conversation at a time
- Timekeeper to monitor discussion and align to agenda
- Topics and questions scheduled for future discussion will be saved in the Parking Lot

Rhode Island PST Advisory Collaboration

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PST Advisory AMF & GMP Subcommittee Meetings and Preliminary Agendas

Stakeholder Collaboration (i.e., Subcommittee meetings and discussions)

Obtain Feedback and Seek Alignment on Proposals and Approaches

Review Initial, Refined and Final Proposals

Jun 21, 2022

- **RI Division and OER Meeting**
- Introductions
- Proposed timeline
- Preliminary agenda for PST meetings
- AMF Introduction and overview of key areas
- GMP Introduction and coordination

July 14, 2022

- **PST Advisory Meeting**
- Introductions
- PPL Background and Experience
- Full Scale Enabling Platform
- Detailed Deployment Plan
- Functionality Timing
- ASA coverage
- AMF cost review
- GMP study scope and approach
- GMP forecast analysis

Aug 2, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Customer Engagement Plan
- AMF Opt-out
- AMF Customer value streams
- AMF Auto-notification
- AMF Benefits

Aug 16, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Data access, privacy, governance
- AMF Cyber Security
- AMF Cost and Benefit Recap
- Cost Recovery and Revenue Requirements
- GMP scenario analysis
- GMP solution development
- GMP ISR Coordination plans

Sept 1, 2022

- **PUC Technical Session**

September 2022 ★

- **File AMF**
- AMF Includes Business Case, Testimonies and BCA
- Coordinate with GMP execution plan and BCA

w/o Oct 20, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- GMP Alternative recommendation
- GMP BCA review

December 2022 ★

- **File GMP**
- GMP Includes Business Case, Testimonies and BCA
- Coordinate with ISR and AMF details

AMF – Advanced Metering Functionality
GMP – Grid Modernization Plan
BCA – Benefit-Cost Analysis

★ September 2022
AMF Targeted Filing Date

★ December 2022
GMP Targeted Filing Date

🟦 Initial alignment meeting with RI Division and OER
■ PST Advisory Sub-Committee Meeting AMF
🟩 PST Advisory Sub-Committee Meeting GMP
🟥 PUC Technical Session

Introductions, Objectives and Background

AMF Business Case Overview

AMF is foundational to RIE achieving a vision of enabling clean, fair, and affordable energy future.

Need:

- Operational: Approximately 60% of the AMR meters are at the end of their design life.
- Environmental: Achieve clean energy mandate of Net-zero carbon emissions in Rhode Island
- Customer Expectations: Manage energy usage; superior customer experience.
- Modernized System: Increased visibility/control (planning, integration, management).

Value:

- BCA developed and refined consistent with the Docket 4600 Framework.
- Net benefits: $ 734.6 million NPV (opt-in)
- Net costs: $189.6 million NPV
- BCA Ratios: 3.9 (opt-in)

Accountability:

- Upfront adjustment to the revenue requirement.
- Semi-annual reporting of AMF metrics.

PST Meeting Reflection and Follow-up

PST Advisory Group 8/2 Customer Engagement Follow-Ups

- **How will you handle the exchange of meters for the 900 large C&I customers?**
  - Majority of C&I customers will be included in the Sector Deployment Plan
  - 900 C&I customers have unique metering that are currently out of scope in the Business Plan
- **What is your strategy to engage renting and non-English speaking customers?**
  - The deployment vendor will get a daily refresh of a customer file from the CIS system containing customer information such as billing and premise address, landlord/tenant information
  - Whoever resides at the premise and is impacted by the meter exchange will be contacted
  - Materials will be published in English as well as Spanish and Portuguese where appropriate.
  - Follow up meeting scheduled to get more feedback for the CEP
- **What will the customer portal look like with TVR?**
  - The TVR portion of the customer portal has not been designed.
  - The vision is to include pricing information along with the interval information of the Customer Portal
  - Specifics can not be provided before the TVR is defined

PST Advisory Group 8/2 BCA Follow-Ups

- **Research on customer behavior that led to the 1.5% energy reduction number used in the benefits?**
  - “Got Data? The Value of Energy Data Access to Consumers” Jan 2016
    - “Since 2010 **12 other studies that indicate energy savings potential of 6% - 18% when customers have easy access to meter data.”**
  - Energy Watch (June 2019) : “Smart meters reduce average electricity consumption by 10% per customer.”
  - “New guidance on conducting energy consumption analysis” Dec 2020:
    - “BEIS estimates that the smart meter roll-out will reduce household electricity and gas consumption by 3% and 2.2% respectively.”
  - “Leveraging Advanced Metering Infrastructure to Save Energy” Jan 2020:
    - “Studies on customer feedback suggest different degrees of impact. Buchanan, Russo, and Anderson (2015) conclude that there is limited evidence that feedback alone is effective in getting customers to reduce energy use. Karlin, Zinger, and Ford (2015), however, conclude that feedback is a promising strategy to promote energy conservation, but that this depends on how information is conveyed to customers (e.g., via social norms, anchoring, and other behavioral tools) to motivate them to take actions that affect their energy use. Sussman and Chikumbo (2016) find that most real-time feedback programs using opt-in designs report net electricity savings in the 5–8% range.”
- **What are your projected EV numbers in order to achieve 40% GHG reductions?**
  - The EV projections range from ~7,000 EVs projected in 2022 to ~750,000 EVs projected in 2041

AMF: Whole House & Electric Vehicle TVR Opt-In & Opt-Out Comparison - NPV ($M)

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As of August 10, 2022		
Business Case Component	**Opt-In Case**	**Opt-Out Case**
A. Costs (20-Year NPV)	**$189.64**	**$189.64**
B. Benefits (20-Year NPV)		
Utility - Opt-In/Opt-Out	$113.13	$471.66
Utility - All Other	$238.60	$238.60
Direct Customer - Opt-In/Opt-Out	$0.00	$0.00
Direct Customer - All Other	$225.46	$225.46
Societal - Opt-In/Opt-Out	$2.51	$5.88
Societal - All Other	$154.90	$154.90
C. Total Benefits (20-Year NPV)	**$734.60**	**$1,096.51**
Benefits Less Costs	$544.96	$906.87
Benefit/Cost Ratio	3.9	5.8

- Base assumption of Opt-In results in Benefit/Cost ratio of 3.9
- Using Opt-Out approach results in Benefit/Cost ratio of 5.8
- Some Utility and some Societal benefits change while Direct Customer benefits do not change

Assumptions:

- EV forecast meets 2040 goal of 80% GHG reduction
- Assumed TOU/CPP & TVR Opt-In = 20% participation; Assumed TOU/CPP & TVR Opt-Out = 85% participation
- Used AESC 2021 avoided costs
- Assumed peak savings of 20% for Whole House and range of 28% to 60% for EVs over 20 years

AMF Data Governance and Data Security

People, Process, Technology, and Purpose are Key

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- People – The requirement for greater security and faster delivery cycles requires changes in team make up and requires regular training. Security is integrated through the business for security/compliance requirements.

  Company maintains a cybersecurity organization comprised of individuals who are trained, certified and experienced in information and cybersecurity. Investment in, and ongoing assessment of our cyber skills is vital to the success of our cybersecurity function.

- Processes – Software and components need to be tracked as they change and as well as the vulnerabilities affecting them. A systematic process is needed since manual processes for tracking vulnerabilities as they are disclosed are unreliable.

  Company has a Data Governance Council that is made up of a cross-functional body of departments to ensure the governance initiatives are coordinated in the most functional manner with ongoing efforts across PPL. Company leverages internal security policies derived from best practices designed to look for novel and effective ways to protect the company's assets from current and emerging threats.

- Technology – Signature-based solutions providing ground truth based on output and continuous monitoring of newly disclosed vulnerabilities and compromises mapped to production software and associated systems

  AMF system will be evaluated for compliance with cybersecurity requirements derived from the Company's Enterprise Security Standards and appropriate industry security standards and frameworks. This evaluation process will continue throughout the development lifecycle

- Purpose – Evaluate the risk and possible repercussions

  Company considers not only the potential impact to the flow of power to customers, but also the intended flow of data through the company's System(s).

PPL Data Governance Plan

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- Defines pertinent policies addressing data privacy, data governance, information classification, and Cybersecurity and enterprise security standards
- Supports critical infrastructure and vital business functions including AMF
- Framework includes a comprehensive set of principles and standards:
  - ✓ Data Governance Policy
  - ✓ PPL Standards of Integrity
  - ✓ PPL Responsible Behavior Program
  - ✓ Information Security
  - ✓ Information Classification and Handling
  - ✓ Electronic Information Security
  - ✓ Records Management
  - ✓ PPL Cybersecurity Policy
  - ✓ PPL FERC Standards of Conduct
  - ✓ PPL Enterprise Information Security Policy
  - ✓ Data Security Standard
- Designed to ensure the data generated by the Company and through its AMF:
  - Collected, managed, stored, transferred, and protected in a way that preserves customer privacy
  - Practices are consistent with cybersecurity requirements
  - Facilitates access to further operational requirements
  - Enables grid modernization and clean energy objectives

PPL Data Governance Policy

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Data Governance Policy (Governance Team/Roles & Responsibilities)

- Define the roles and responsibilities for different data creation and usage types, and clear lines of accountability.
- Develop best practices for effective data management and protection.
- Protects data against internal and external threats
- Ensure that data consumers complies with applicable laws, regulations, exchange, and standards
- Ensure that a data trail is effectively documented

AMF Data Privacy Review (Framework to communicate with customers and third parties)

- Data Access Principles
  - Utilizes widely recognized data privacy frameworks for AMF
  - Supported by NIST as long-established and best practices that are readily available and straightforward concepts to consistently utilize when building privacy controls into processes
- Data Privacy Review
  - Compares the NIST Guidelines to the Company’s existing privacy policies, procedures and the AMF implementation plan to identify where best practice is in place or further alignment is needed

AMF Data Privacy Review

- AMF Data Privacy
  - Evolving AMF technologies brings new types of information that can involve privacy
  - Need to review existing policies to confirm adequate coverage
  - Standard practices are required to safeguard information
  - Consumers need notification of privacy exposures
- Using NIST Interagency Report 7628 volume 2 on Privacy and the Smart Grid as a basis for a review
- Applies to AMF and to GMP

DRAFT - Data Privacy Review Categories

1 Management and Accountability
2 Notice and Purpose
3 Choice and Consent
4 Collection and Scope
5 Use and Retention
6 Individual Access
7 Disclosure and Limiting Use
8 Safety and Safeguards
9 Accuracy and Quality
10 Openness, Monitoring, and Challenging Compliance
11 Personal Information in the Smart Grid
12 Wireless Access to Smart Meters and Secondary Devices
13 Commisioning, Registration, and Enrollment for Smart Devices
14 Smart Grid Data Acess by Third Parties
15 Plug-in Electric Vehicles Privacy Concerns
16 Awareness and Training
17 Mitigating Privacy Concerns within the Smart Grid
18 Emerging Smart Grid Privacy Risks

Cyber Security: Technology and Process

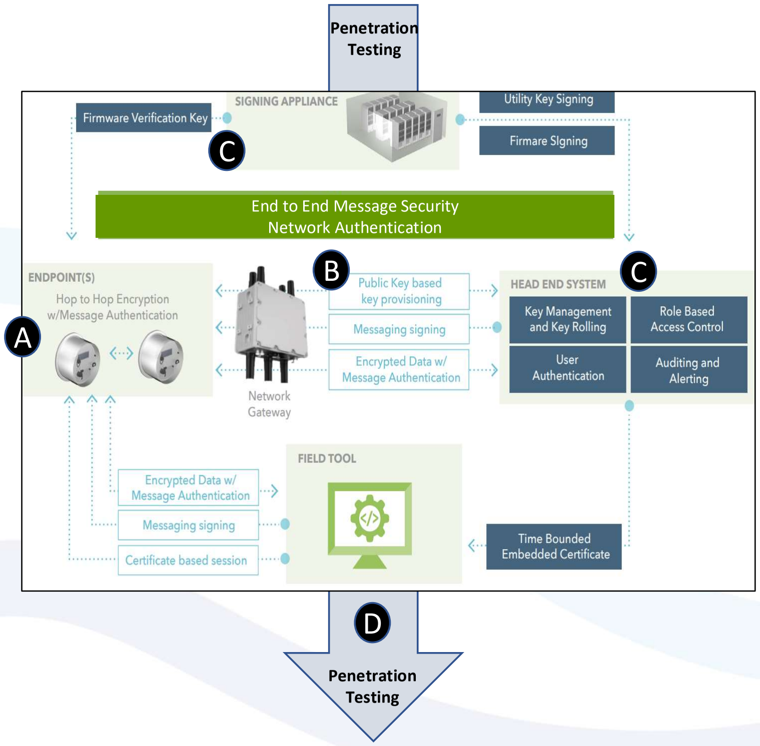
A. Data encryption capability for transit at the networking layers on the devices
  - Uses advanced encryption protocol standard to protect the transfer of data online

B. RF network provides a uniquely keyed application layer messaging encryption to ensure privacy between an endpoint and the associated head end system
  - Uses 3-layered approach provides best in class cryptography and privacy controls

C. Resistance and local security tamper resistance protects devices from being modified and allows for monitoring

D. Penetration testing will also be required by a third-party focusing on the network and software layers

E. Ongoing testing coupled with design characteristics, which includes A+B+C+D, ensures the entire system is secure



Green Button for Customers, Third Parties/NPPs

- RIE can generate Green Button data from AMF meters
- Green Button Connect will be available through the Customer Portal designed to provide customers with secure access to energy usage in a consumer-friendly and computer-friendly format.
- Provides customers with the ability to take advantage of a growing array of services to help manage energy use and save on their bills.
- Enables and incentivizes entrepreneurs to build innovative applications, products and services which will help consumers manage energy use
- Benefits utilities that receive numerous requests for information
- Customers can authorize the sharing of their data with third-parties.

Performance Metrics and Reporting

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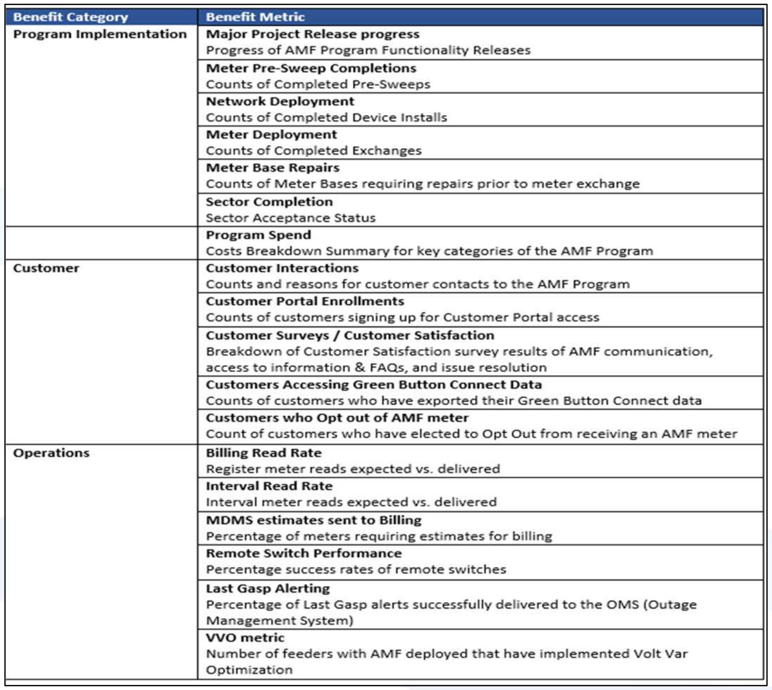
- Suite of metrics designed to provide a transparent assessment progress of AMF implementation in key areas
- Focus is on providing metrics for three key areas:
  - Implementation
  - Customer
  - Operations
- AMF Program Report to be provided at the end of the year with mid-year project status update meeting

DRAFT Performance Metrics



Benefit Category	Benefit Metric
Program Implementation	**Major Project Release progress** Progress of AMF Program Functionality Releases
	Meter Pre-Sweep Completions Counts of Completed Pre-Sweeps
	Network Deployment Counts of Completed Device Installs
	Meter Deployment Counts of Completed Exchanges
	Meter Base Repairs Counts of Meter Bases requiring repairs prior to meter exchange
	Sector Completion Sector Acceptance Status
	Program Spend Costs Breakdown Summary for key categories of the AMF Program
Customer	**Customer Interactions** Counts and reasons for customer contacts to the AMF Program
	Customer Portal Enrollments Counts of customers signing up for Customer Portal access
	Customer Surveys / Customer Satisfaction Breakdown of Customer Satisfaction survey results of AMF communication, access to information & FAQs, and issue resolution
	Customers Accessing Green Button Connect Data Counts of customers who have exported their Green Button Connect data
	Customers who Opt out of AMF meter Count of customers who have elected to Opt Out from receiving an AMF meter
Operations	**Billing Read Rate** Register meter reads expected vs. delivered
	Interval Read Rate Interval meter reads expected vs. delivered
	MDMS estimates sent to Billing Percentage of meters requiring estimates for billing
	Remote Switch Performance Percentage success rates of remote switches
	Last Gasp Alerting Percentage of Last Gasp alerts successfully delivered to the OMS (Outage Management System)
	VVO metric Number of feeders with AMF deployed that have implemented Volt Var Optimization

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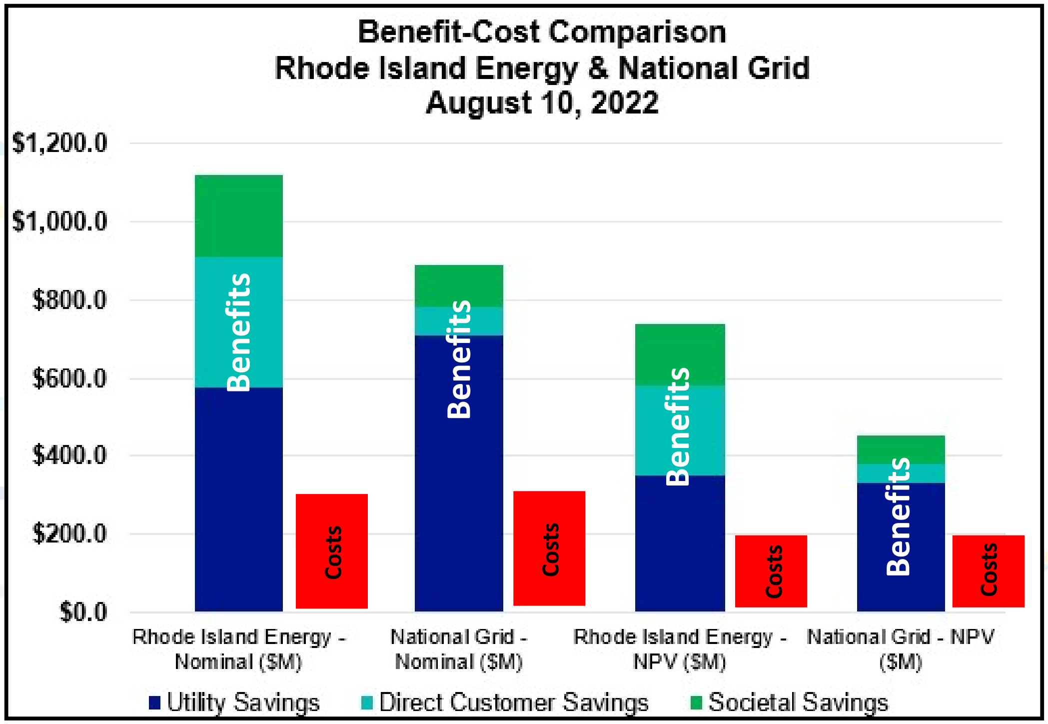
AMF Cost-Benefit Recap & Sensitivities

Benefits & Costs: Comparison to National Grid – Opt-In

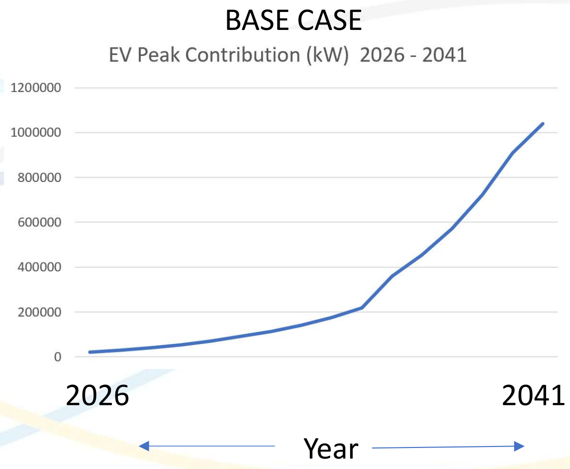

Benefit-Cost Comparison
Rhode Island Energy & National Grid
August 10, 2022

Nominal ($M)	RIE	NG
Utility Savings	$ 574.8	$ 708.89
Direct Customer Savings	$ 331.9	$ 70.77
Societal Savings	$ 210.4	$ 109.73
Total Savings	$ 1,117.1	$ 889.4
AMF Costs	$ 288.7	$ 289.4
Benefit/ Cost Ratio	3.9	3.1

NPV ($M)	RIE	NG
Utility Savings	$ 352.4	$ 333.50
Direct Customer Savings	$ 225.5	$ 48.46
Societal Savings	$ 156.7	$ 72.90
Total Savings	$ 734.6	$ 454.9
AMF Costs	$ 189.6	$ 192.6
Benefit/ Cost Ratio	3.9	2.4

Assumptions for EV Time Varying Rates

- EV Time Varying Rates assumptions included in the Base Case BCA
  - Opt-In Participation & achievement of peak savings where both phased-in
  - Analysis includes years 2026 – 2041 where number of EVs grow to 29.5k to 750k over the period
  - Opt-In participation increases from 5% - 20% by 2029 and remains at 20% through the period (conservative)
  - Peak contribution per EV increases from .69 – 1.38 KW / EV through the period
  - Peak savings increased from 42% - 60%
  - Total kW for EVs range from 20,193 kW to 1,039,481 kW through the period 2026 – 2041 as shown in chart
  - Avoided Capacity is $38.47 – 57.14
- Additional sensitivities for Opt-In participation of 10% - 90% and peak reduction for 2026 = 21 – 55% and for 2041 = 30 – 78% resulting in BCA of 3.7 – 4.4



Significantly positive B/C ratios for all ranges of sensitives that were applied: base case is conservative

Assumptions Whole House TOU/CPP Time Varying Rates

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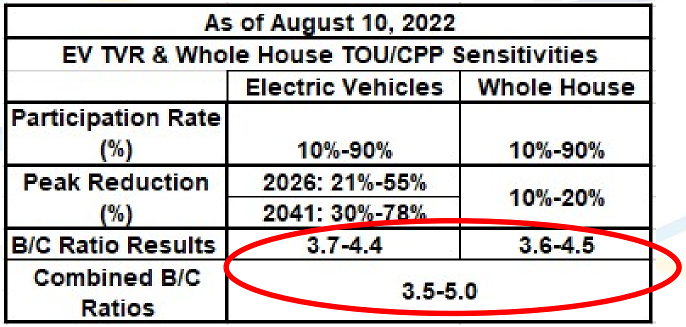
- Whole house TOU/CPP included in the Base Case BCA
    - Opt-In Participation and achievement was phased-in
    - Residential peak held steady at 94 MW (conservative)
    - Analysis includes years 2026 – 2041
    - Opt-In participation increases from 5% - 20% by 2029 and remains at 20% through the period
    - Opt-In achievement increases from 33% , 66% and 100% in years 2026, 2027 and 2028 and then remaining throughout
    - Peak savings increases from 1.6 – 18.8 MW by 2029 and then remains throughout the period
    - Avoided Capacity is $38.47 – 57.14
- Additional sensitivities performed for Opt-In participation of 10% - 90% and peak reduction of 10 – 20% resulting in BCA Ratio results of 3.6 – 5.0

Significantly positive B/C ratios for all ranges of sensitives that were applied: base case is conservative

Sensitivities: Electric Vehicle TVR & Whole House TOU/CPP

- Varied Participation Rates and Peak Reduction percentages for both Electric Vehicles and Whole House rate programs
- Combined whole house and EV B/C ratios are significant at lower participation and peak reduction percentages (3.5)
- Base case for AMF Business Plan is conservative and positive



As of August 10, 2022

EV TVR & Whole House TOU/CPP Sensitivities

	Electric Vehicles	Whole House
Participation Rate (%)	10%-90%	10%-90%
Peak Reduction (%)	2026: 21%-55% 2041: 30%-78%	10%-20%
B/C Ratio Results	3.7-4.4	3.6-4.5
Combined B/C Ratios	3.5-5.0	

Combined Benefit / Cost ratios for TVR are significantly positive for the full range of sensitivities

Sensitivities: Benefits & Costs

Benefits

- Developed sensitivities for five of the largest and/or most uncertain benefits
- Varied each of the benefits by +/-20%
- B/C range from 3.7-4.0 for individual sensitivities
- Combined B/C ratio is 3.2 for -20% and 4.5 for +20%

Costs

- Varied total costs +/-10%
- Varied System Costs +/-25%
- B/C range from 3.5-4.3 for individual sensitivities
- Combined B/C ratio is 3.3 for +10%/+25% (unfavorable)
- Combined B/C ratio is 4.6 for +10%/-25%

Benefits Sensitivities

Benefit	B/C Ratio Unfavorable: -20%	B/C Ratio Favorable: +20%
Faster Outage Notification	3.7	4.0
Reduced Personnel	3.8	3.9
Energy Insights Savings	3.7	4.0
VVO/CVR Benefits (Energy Only)	3.8	4.0
Non-Embedded CO2 Benefits	3.7	4.0
Total Sensitivities	3.2	4.5

Cost Sensitivities

	B/C Ratio Unfavorable: +10% & +25%	B/C Ratio Favorable: -10% & -25%
Total Costs: +/-10%	3.5	4.3
Systems Costs: +/-25%	3.5	4.3
Combination Total and Systems	3.3	4.6

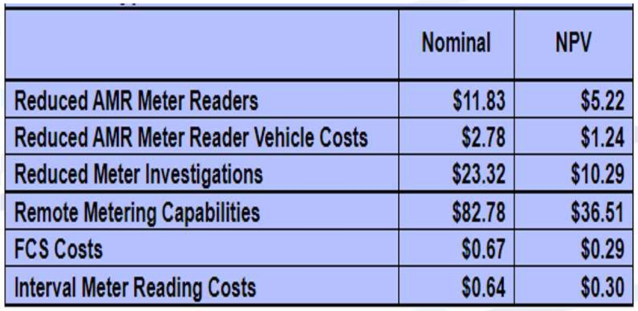
Benefit / Cost ratios are significantly positive for the full range of BCA sensitivities that were applied

Benefits Realized by Customers as Savings

Customers are credited with 80% of projected AMF-driven operational costs:

- Reduced AMR Meter Readers
- Reduced AMR Meter Reader Vehicle Costs
- Reduced Meter Investigations
- Remote Metering Capabilities
- FCS Costs
- Interval Meter Reading Costs

Customer savings in Nominal and NPV ($M)



	Nominal	NPV
Reduced AMR Meter Readers	$11.83	$5.22
Reduced AMR Meter Reader Vehicle Costs	$2.78	$1.24
Reduced Meter Investigations	$23.32	$10.29
Remote Metering Capabilities	$82.78	$36.51
FCS Costs	$0.67	$0.29
Interval Meter Reading Costs	$0.64	$0.30

Benefits that will result in customer savings total $122.0 million Nominal and $53.9 million NPV

AMF Cost Recovery and Revenue Requirements

Revenue Requirements

- Total revenue requirement for 20 years is approximately $320m*
  - Comprised of incremental AMF related capital in-service and O&M costs
  - Reduced for costs already recovered in base rates
  - Reduced to credit customers with 80% of projected AMF-driven operational cost savings until reflected in the next base rate case (similar to NG proposal)
- Modeled over 20 years, peak year of revenue requirement is expected to be year 4 of cost recovery, declines after that
- Customer allocation consistent with methodology approved in last distribution base rate case (Docket No. 4770)

* Based on preliminary numbers

Pricing and Customer Considerations

Pricing Considerations:

- Amended Settlement Agreement (Docket No. 4770) does permit reopening for AMF cost recovery
- Distribution base rate case was expected to be filed in Fall 2021
- Proposal to establish a separate AMF factor (per-kWh volumetric)
- Price based on revenue requirement using historical costs (actual dollars spent)
- Change price every ~6 months
- Roll then current rate base into next distribution base rate case

Customer Considerations:

- Pays only for what the company has already spent or placed in-service
- Given a longer time before a distribution base rate case, customers could receive the operational cost savings timely through pricing mechanism if savings realized quicker or more than forecast
- As spend decreases, customer will see a decrease in the factor
- Smaller (though more frequent) price changes for customers

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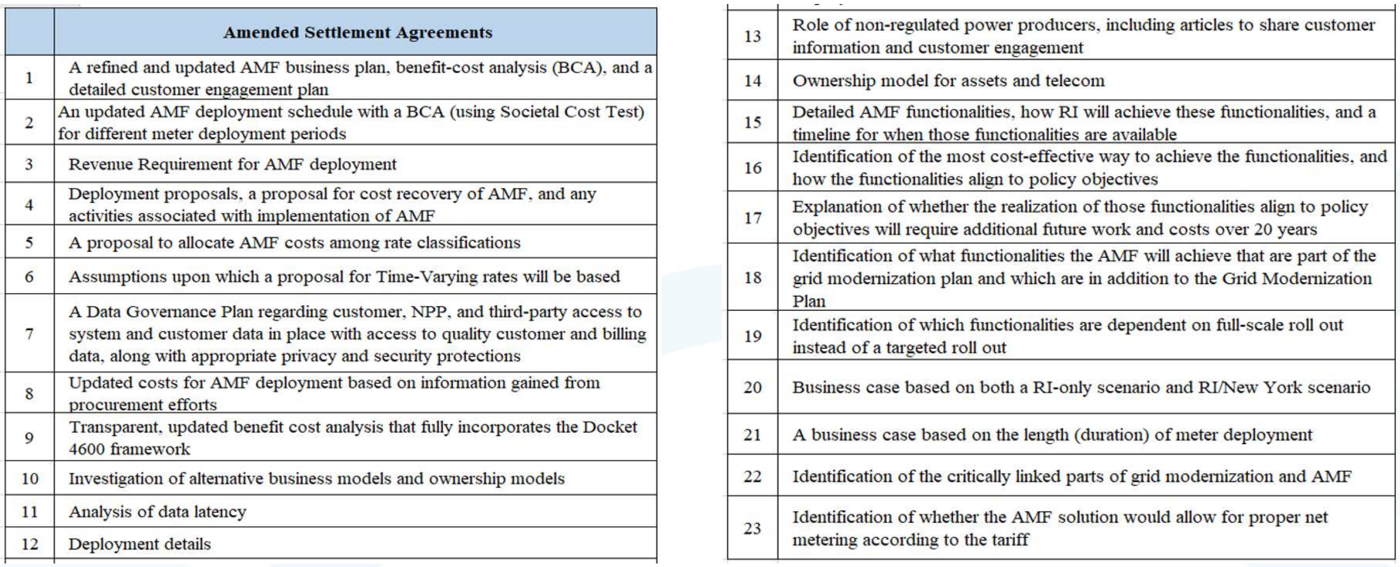
Next Steps

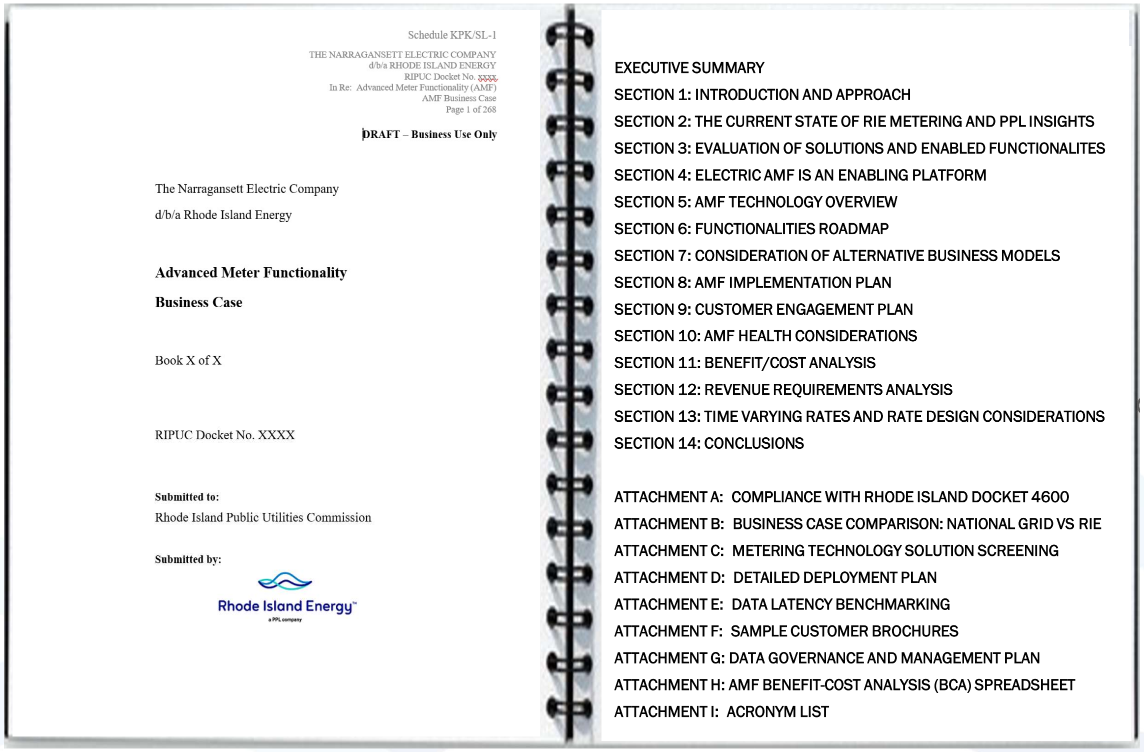
Amended Settlement Agreement Compliance



	Amended Settlement Agreements
1	A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed customer engagement plan
2	An updated AMF deployment schedule with a BCA (using Societal Cost Test) for different meter deployment periods
3	Revenue Requirement for AMF deployment
4	Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF
5	A proposal to allocate AMF costs among rate classifications
6	Assumptions upon which a proposal for Time-Varying rates will be based
7	A Data Governance Plan regarding customer, NPP, and third-party access to system and customer data in place with access to quality customer and billing data, along with appropriate privacy and security protections
8	Updated costs for AMF deployment based on information gained from procurement efforts
9	Transparent, updated benefit cost analysis that fully incorporates the Docket 4600 framework
10	Investigation of alternative business models and ownership models
11	Analysis of data latency
12	Deployment details
13	Role of non-regulated power producers, including articles to share customer information and customer engagement
14	Ownership model for assets and telecom
15	Detailed AMF functionalities, how RI will achieve these functionalities, and a timeline for when those functionalities are available
16	Identification of the most cost-effective way to achieve the functionalities, and how the functionalities align to policy objectives
17	Explanation of whether the realization of those functionalities align to policy objectives will require additional future work and costs over 20 years
18	Identification of what functionalities the AMF will achieve that are part of the grid modernization plan and which are in addition to the Grid Modernization Plan
19	Identification of which functionalities are dependent on full-scale roll out instead of a targeted roll out
20	Business case based on both a RI-only scenario and RI/New York scenario
21	A business case based on the length (duration) of meter deployment
22	Identification of the critically linked parts of grid modernization and AMF
23	Identification of whether the AMF solution would allow for proper net metering according to the tariff

AMF Business Case addressed the Amended Settlement Agreements

Incorporate Feedback into the AMF Business Case and File



Schedule KPK/SL-1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a RHODE ISLAND ENERGY
RIPUC Docket No. xxxx
In Re: Advanced Meter Functionality (AMF)
AMF Business Case
Page 1 of 268

DRAFT – Business Use Only

The Narragansett Electric Company

d/b/a Rhode Island Energy

Advanced Meter Functionality

Business Case

Book X of X

RIPUC Docket No. XXXX

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

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a PPL company

Grid Modernization Plan

Stakeholder Outreach: Scenario Analysis, Solution Development and ISR Coordination

Power Sector Transformation – August 16, 2022

GMP Follow-up, Forecast and Approach in Review

PST Advisory Group Follow-Ups for GMP

PST questions from 7/14/2022 have been incorporated in this presentation:

- Will the messaging incorporate the need for infrastructure build out?
- How will offshore wind that is connected to the transmission system effect distribution?
- What is your strategy regarding storage (battery, vehicle to grid, etc.)?

Forecast / Impact to Peak Demand: A Review

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Key DER Metrics for Milestone Study Years

	GMP DER Forecast Analysis -- Impact to Peak Demand					
	2030		2040		2050	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps, MW	0	200	5	1310	5	2825
# Heat Pumps	54,000	54,000	325,000	325,000	400,000	400,000
Solar PV, MW	0	0	0	0	0	0
Solar PV, nameplate MW	1500	1500	3400	3400	5000	5000
EV Charging, MW	70	80	805	910	1010	238
# Electric Vehicles	87,300	87,300	675,000	675,000	840,000	840,000
RIE Peak Demand, MW	1940	1415	2590	3280	2785	3855

Off-shore wind is considered in the Transmission model; it is not in the Distribution models.

Approach to Distribution System Analysis

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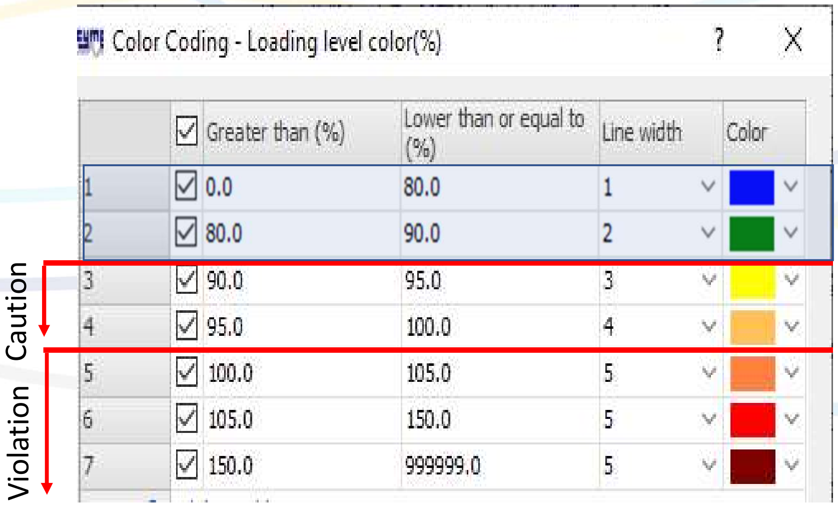
- State-wide analysis to determine the most efficient plan to meet the state's energy policy, growing resiliency and reliability needs, and customer's expectations.
- Scope
  - State-wide distribution analysis
    - ~400 feeders
    - Sub-transmission modeling and testing
    - Traditional area study recommendations included in models
  - System-wide transmission analysis
  - Analysis years – 2030, 2040, 2050 to align with Act on Climate target years
    - Testing may occur in intermediate years for special cases – i.e. when winter peak exceeds summer peak.
  - Cases
    - No Grid Modernization – build for extremes
    - Grid Modernization – manage away extremes
    - Sensitivties
      - Low, Base, High DER forecasts
      - With and without transmission consideration
  - 8760-Hour per year analysis
- Analysis
  - Issue Identification
    - Determine load and voltage issues across hours of the year
    - Determine areas with degrading reliability
    - Determine resiliency needs
  - Case Evaluation
    - No GMP – Base DER Forecast - How would traditional utilities alternatives solve the issues?
    - GMP – Base DER Forecast - How would GMP-type alternatives solve the issues?
      - Sensing, data, communications, dispatch
      - Sensitivities for low and high DER forecasts
      - Sensitivities for with and without transmission
      - Leverage PPL proven technology
- Estimation
  - Leverage PPL subject-matter-expertise
- Benefit Cost Analysis
  - Aligned with Docket 4600
- PST Stakeholder Consultation Throughout

Guide to Analysis Slides

- Each test year will be shown with loading and voltages analysis
  - Cool colors are shaded and have no issues ▭
  - Warm colors are issues

Loading Color Legend



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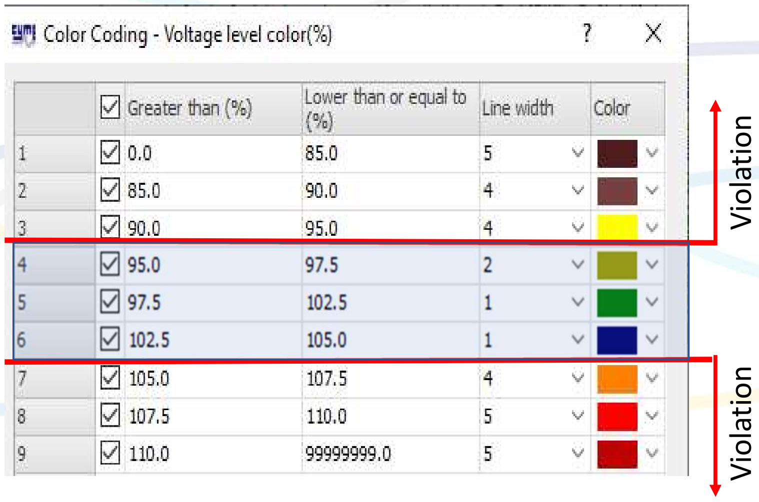
Voltage Color Legend



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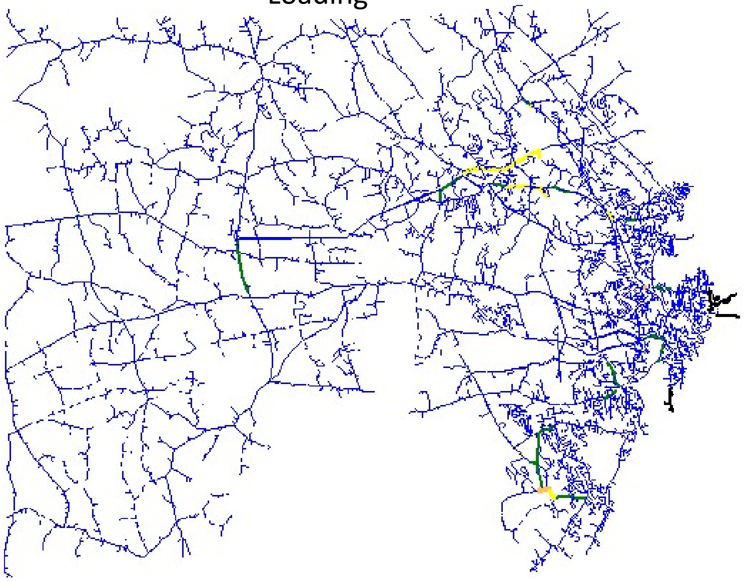
8	☑ 107.5	110.0	5	🟥
9	☑ 110.0	99999999.0	5	🟥

GMP Study Forecast – Northwest Findings (Preliminary)

Starting Model – Example Area – NW Rhode Island

- Base Case is the foundational case that includes all area study recommendations - no existing issues
  - No DER added yet
  - 9 substations, 33 distributions circuits, 4 subtransmission circuits

Loading



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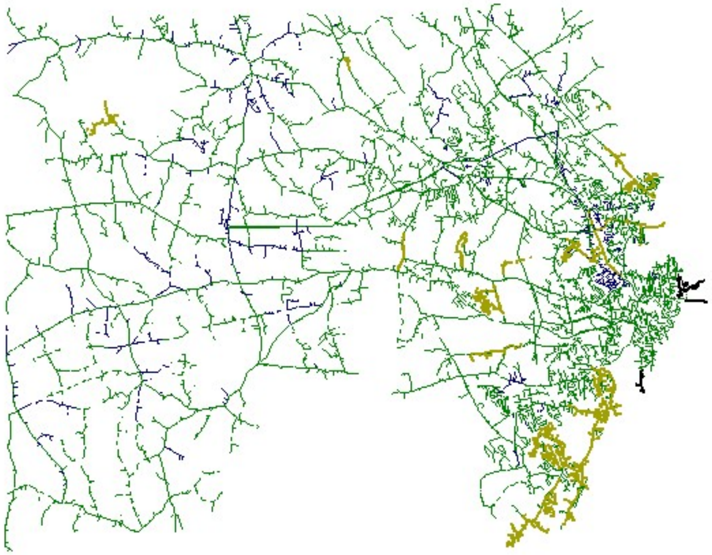
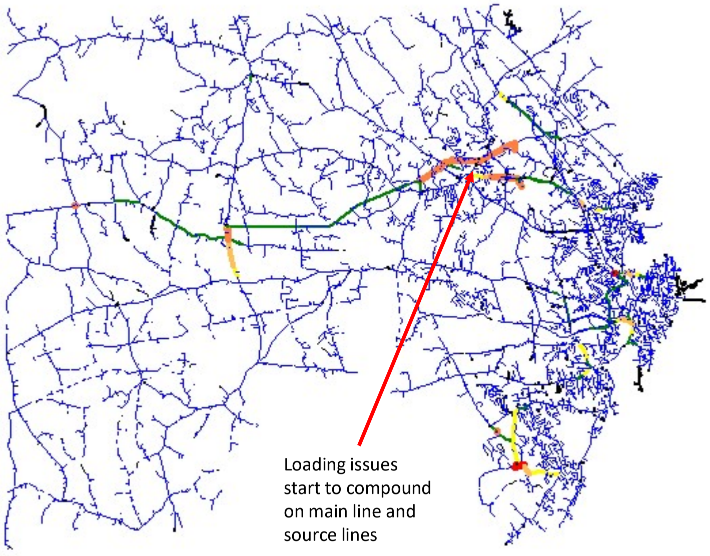


Peak Load Flow Case - 7/22/30 6PM

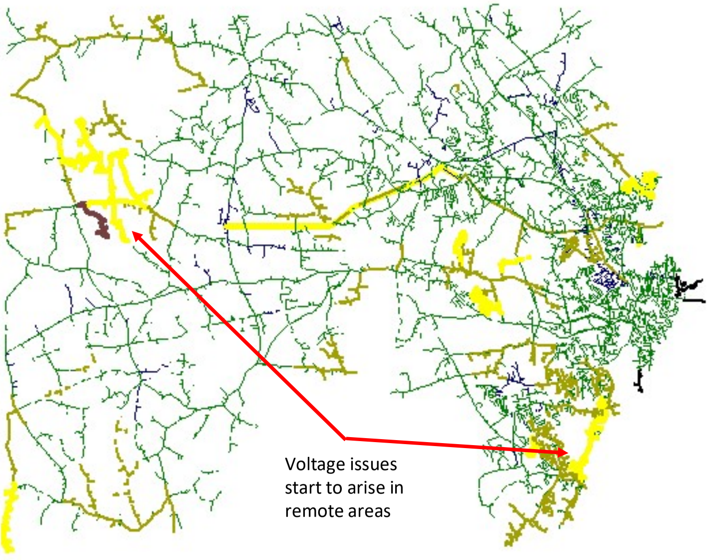
- 2030 case includes DER allocation of EV, EHP, and DG (solar and on-shore wind)
  - 8760 hour analysis conducted – targeted critical date/time shown

Loading



Loading issues start to compound on main line and source lines

Voltage



Voltage issues start to arise in remote areas

High Generation Load Flow Case - 4/16/30 12PM

- 2030 case includes DER allocation of EV, EHP, and DG (solar and on-shore wind)
    - 8760 hour analysis conducted – targeted critical date/time shown

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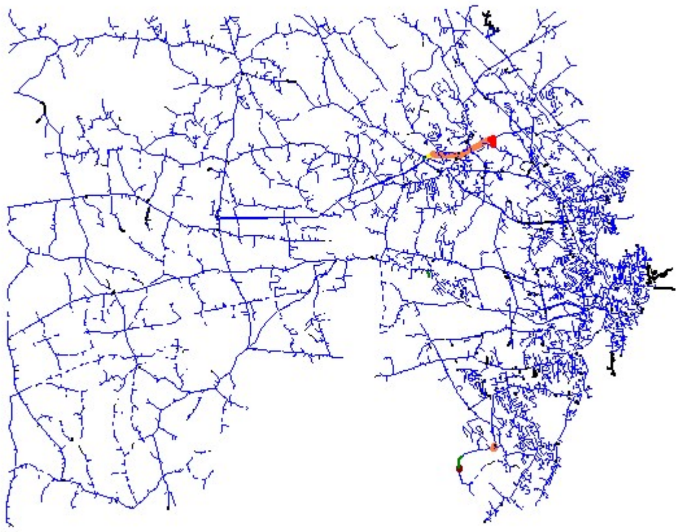
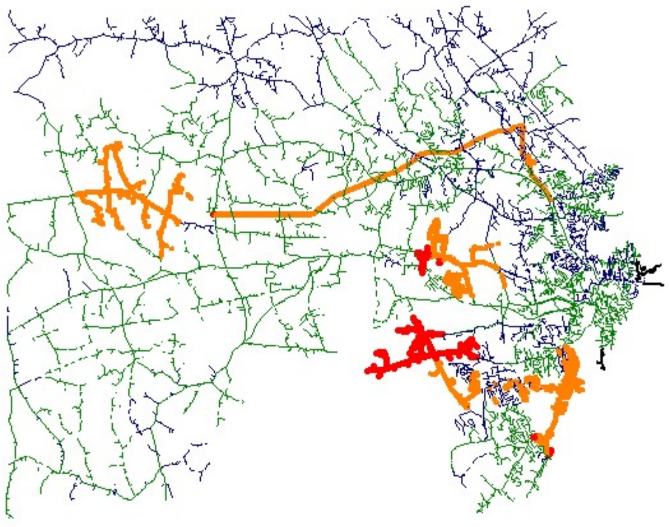


Voltage



2/29/40 3AM Peak Load Flow Voltage

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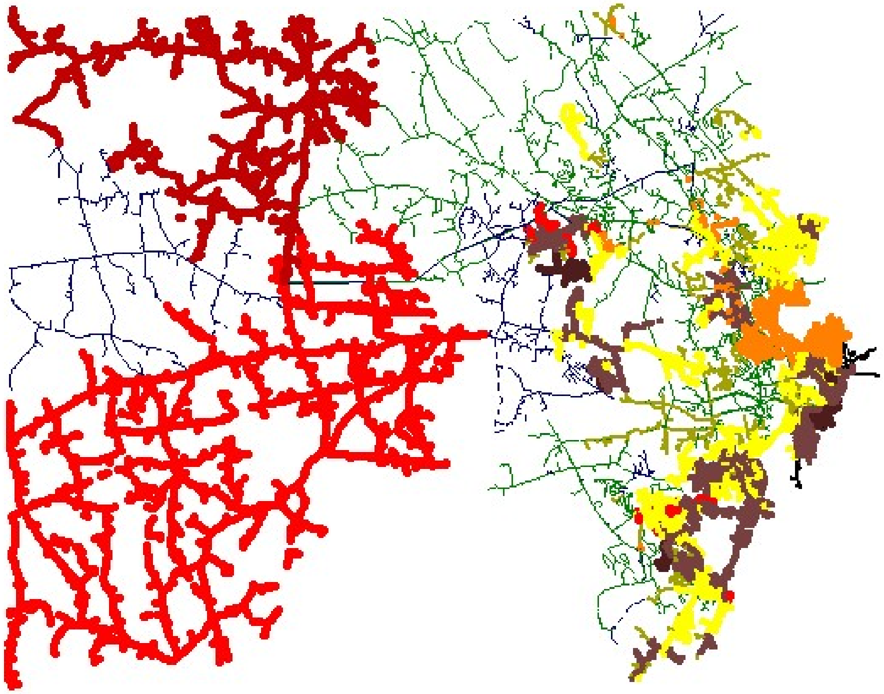

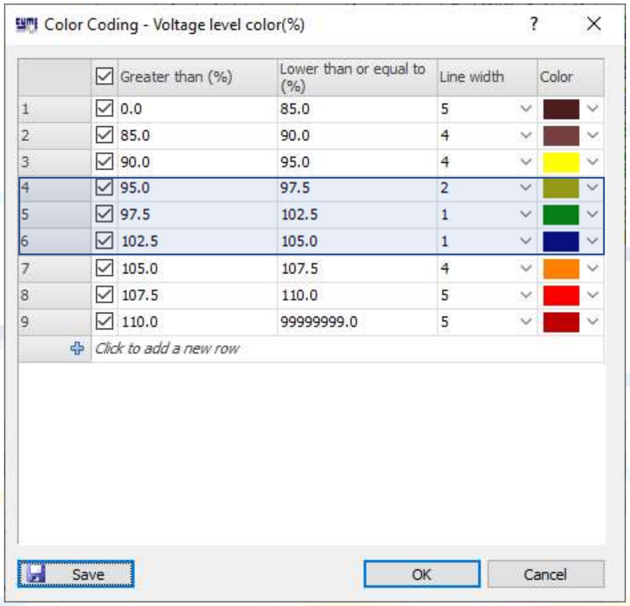

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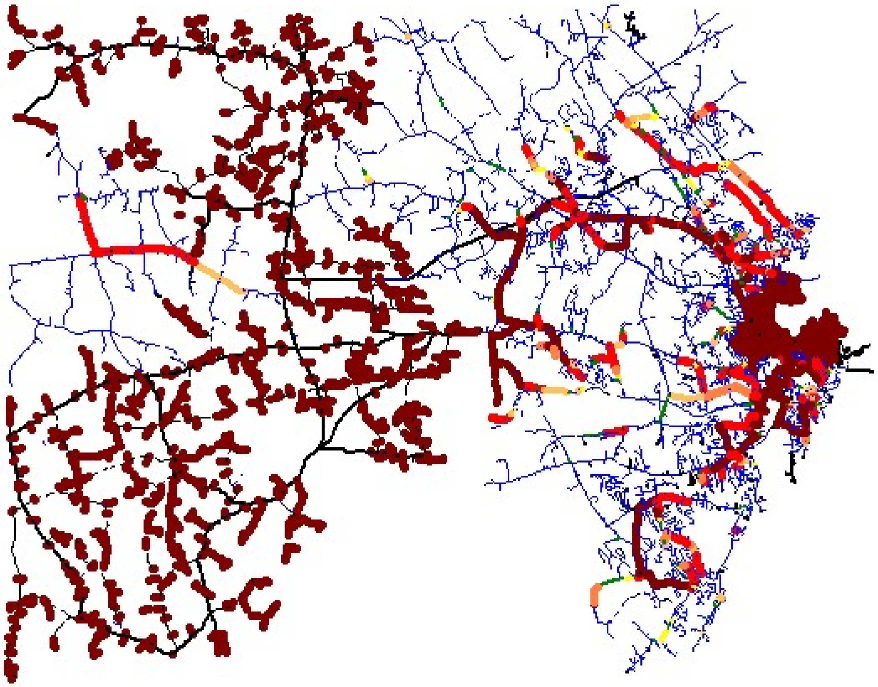
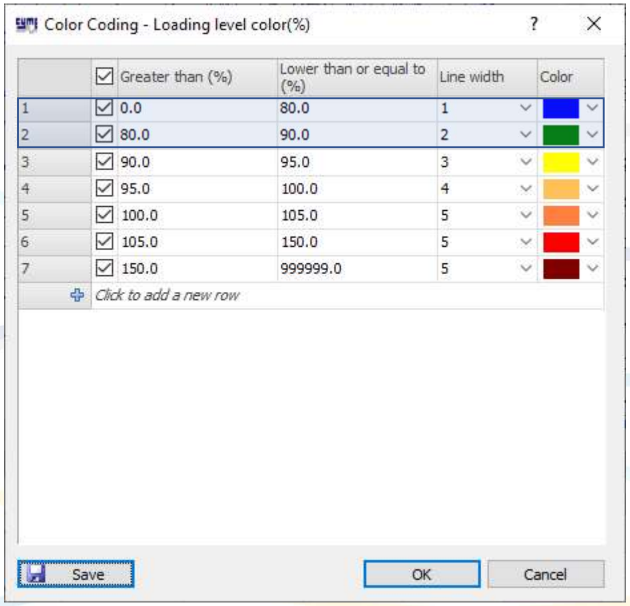
2/29/40 3AM Peak Load Flow Loading





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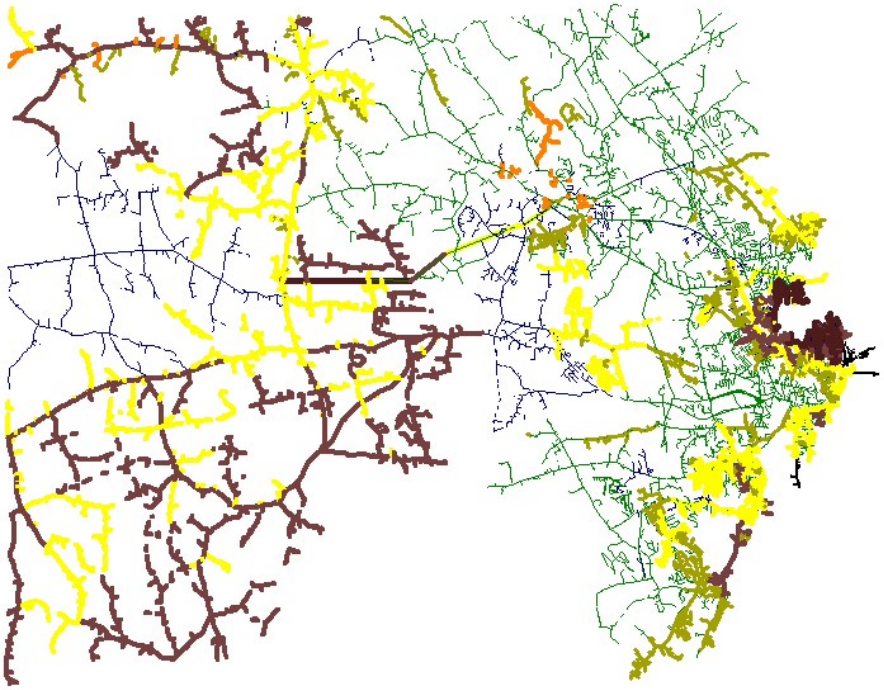
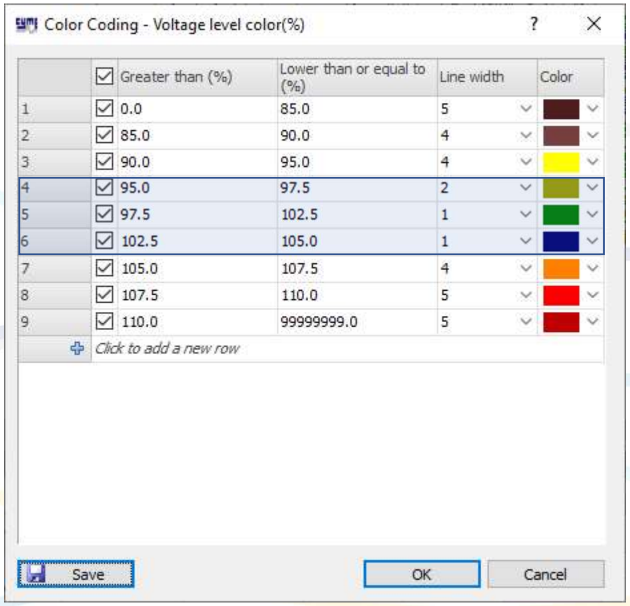
2/21/40 3AM Peak Load Flow Voltage





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2/21/40 3AM Peak Load Flow Loading

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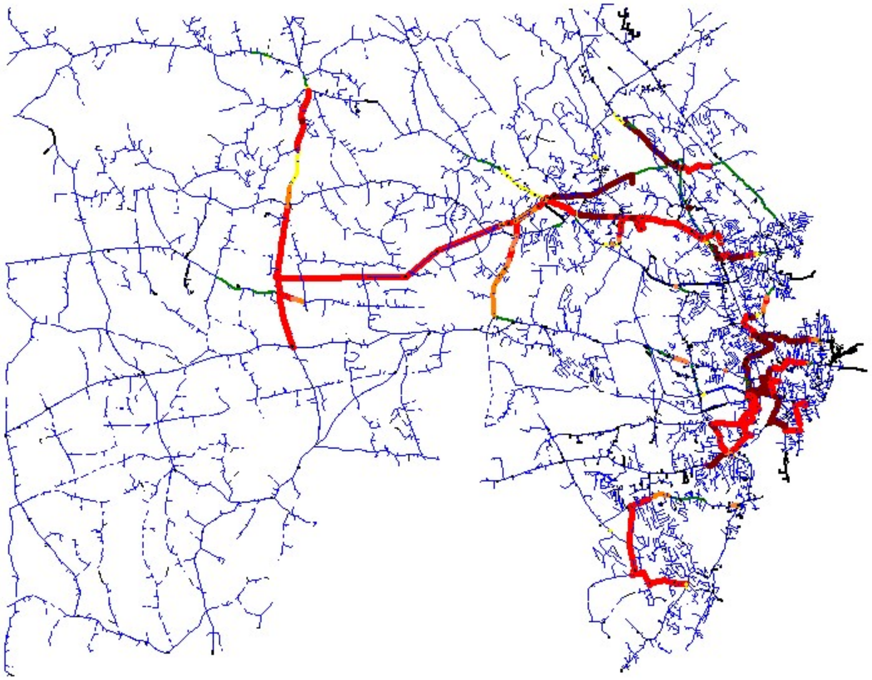

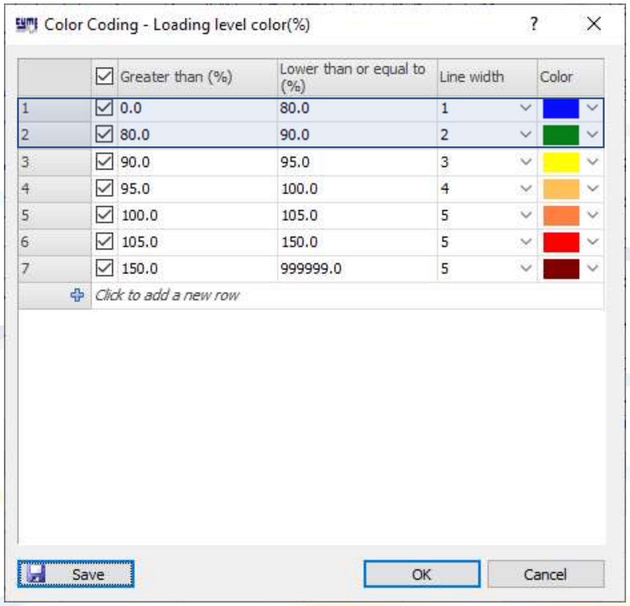

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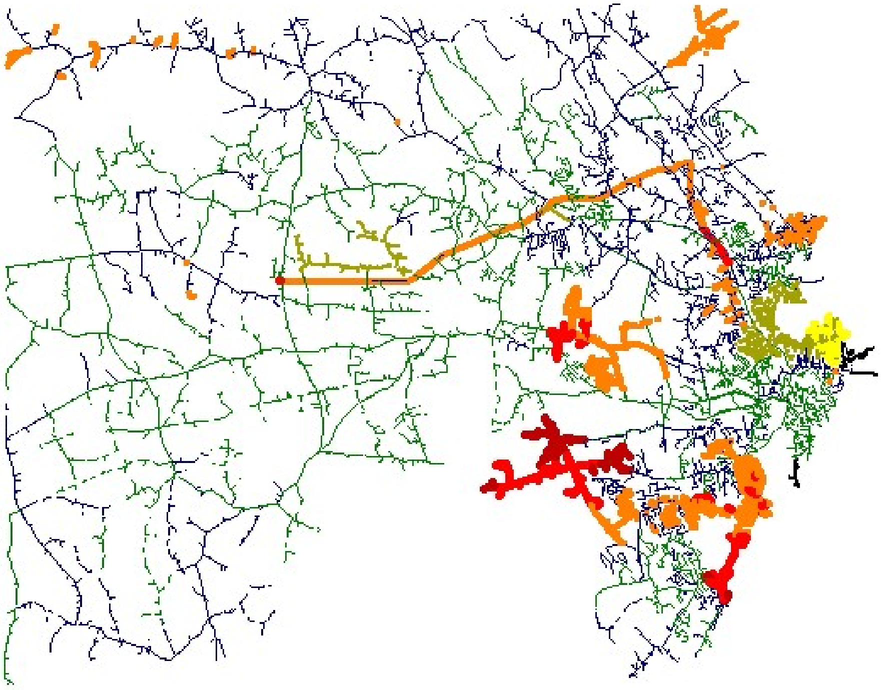
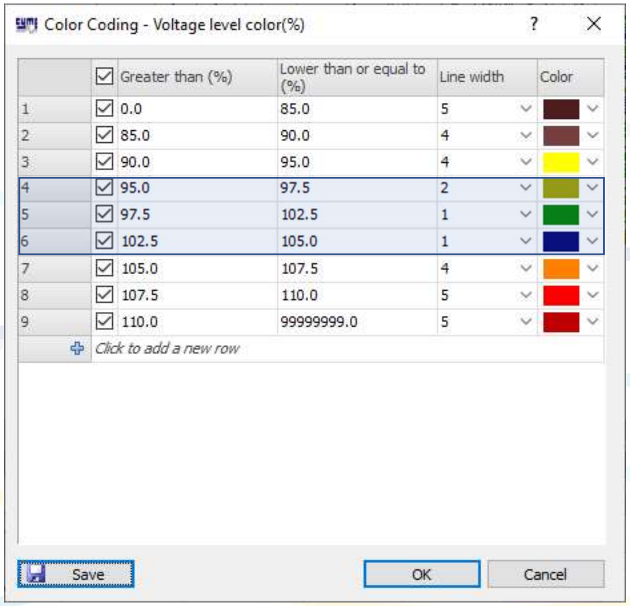
4/16/40 12PM Reverse Peak Load Flow Voltage





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Click to add a new row

4/16/40 12PM Reverse Peak Load Flow Loading

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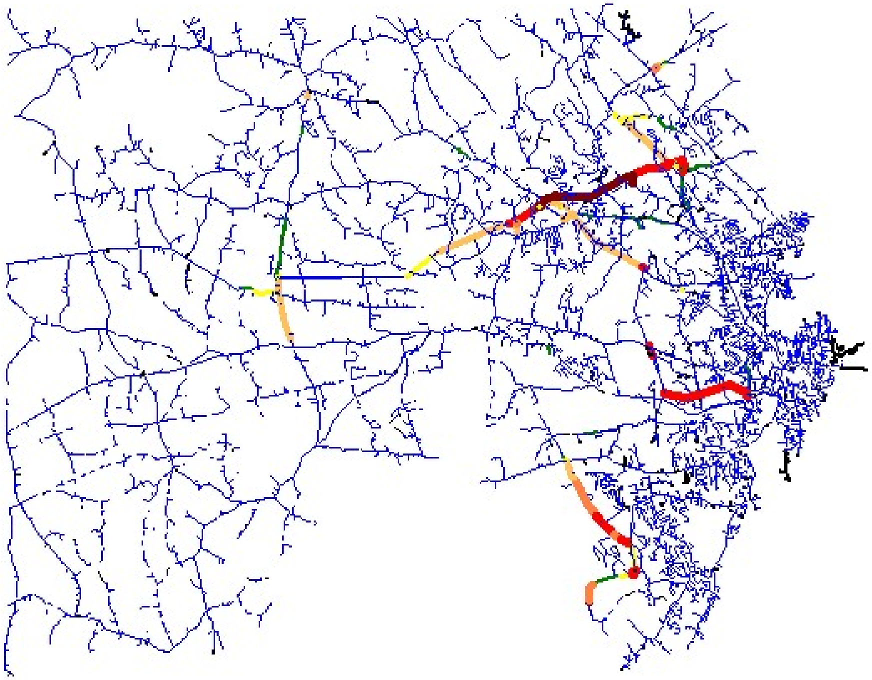

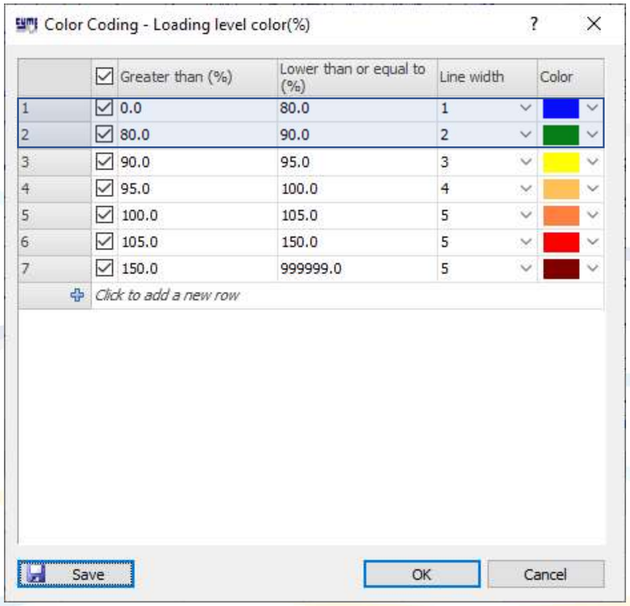

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2/24/50 6AM Peak Load Flow Voltage

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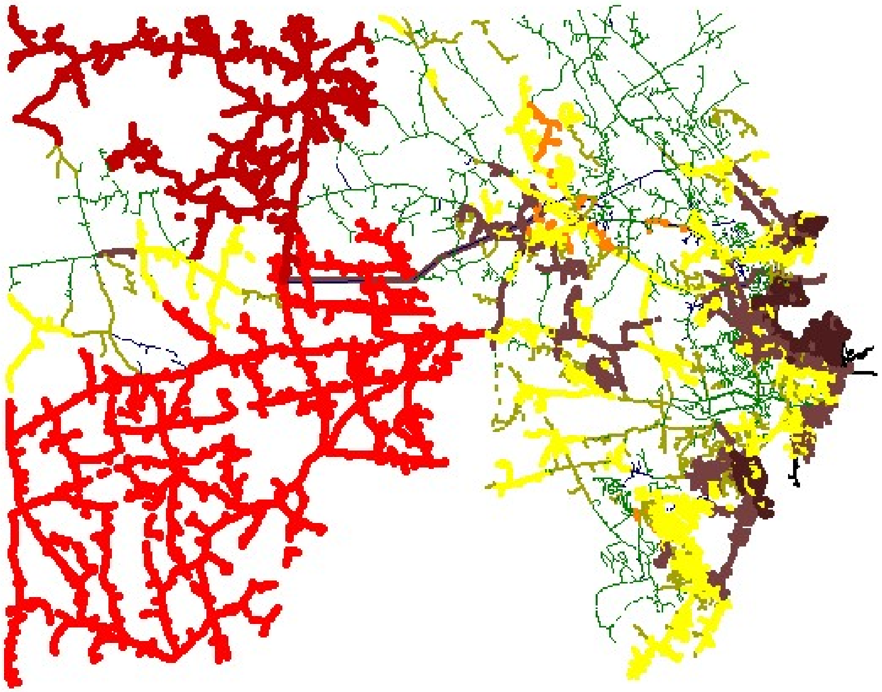

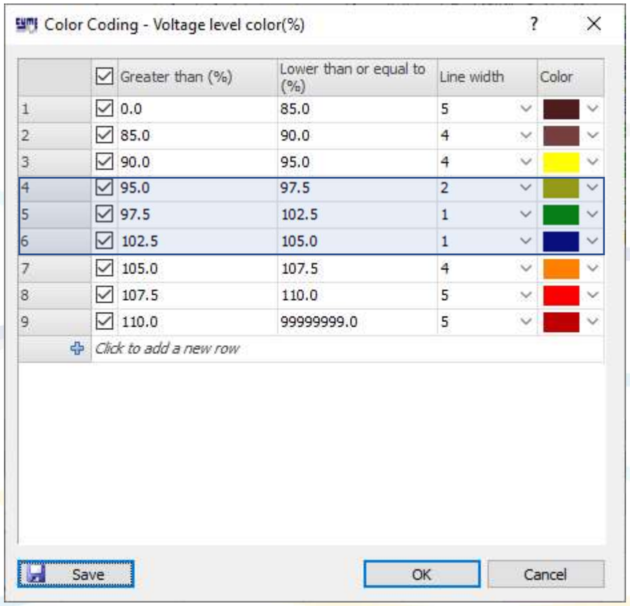

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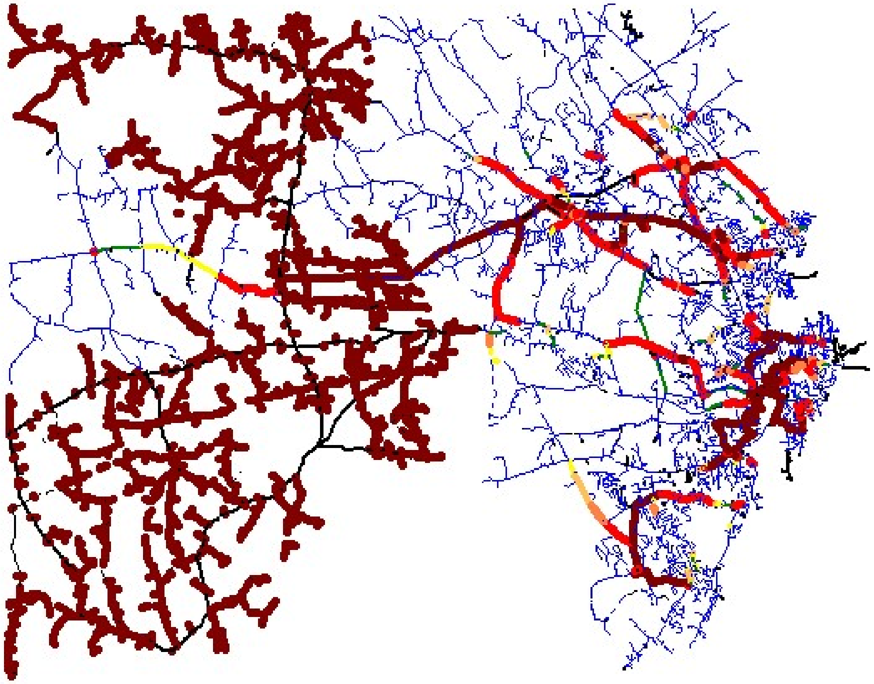
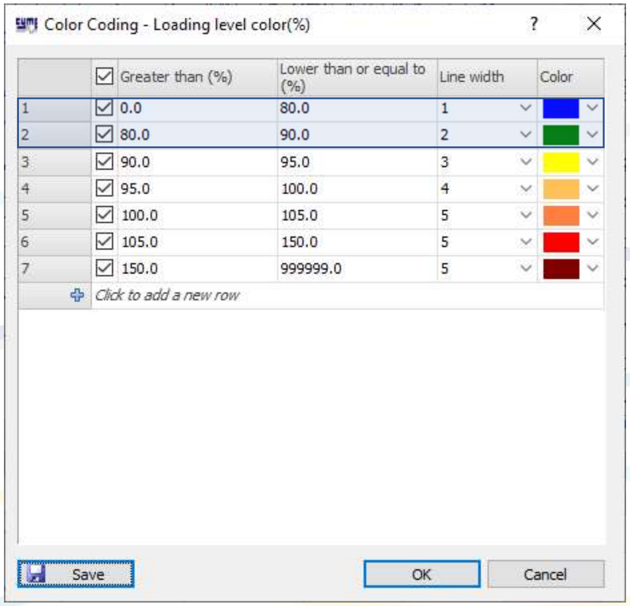
2/24/50 6AM Peak Load Flow Loading





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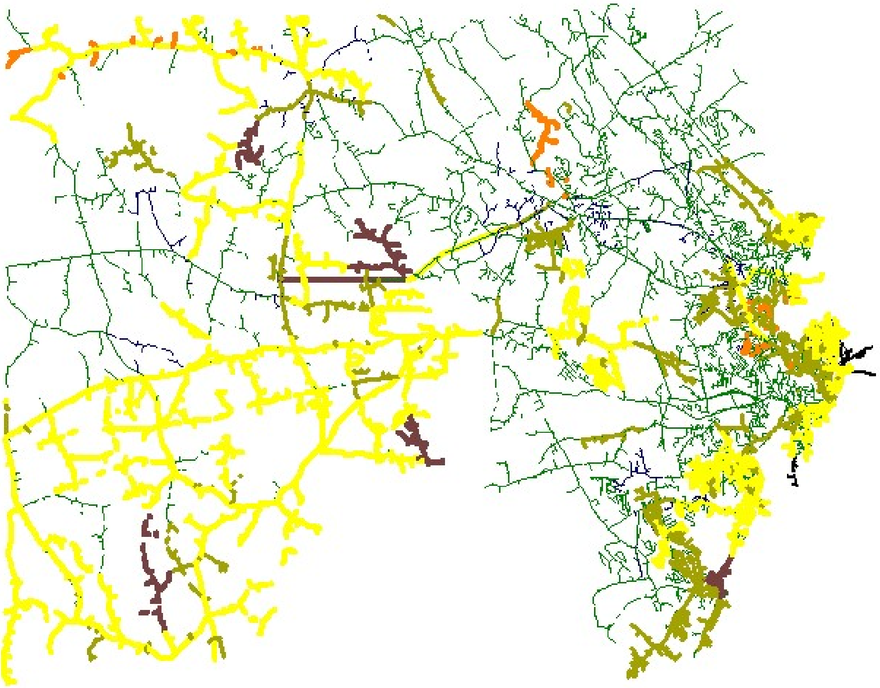
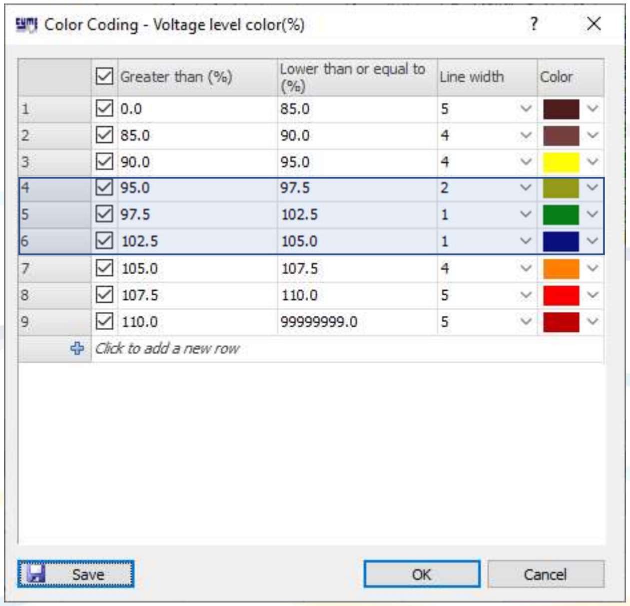
1/29/50 6AM Peak Load Flow Voltage





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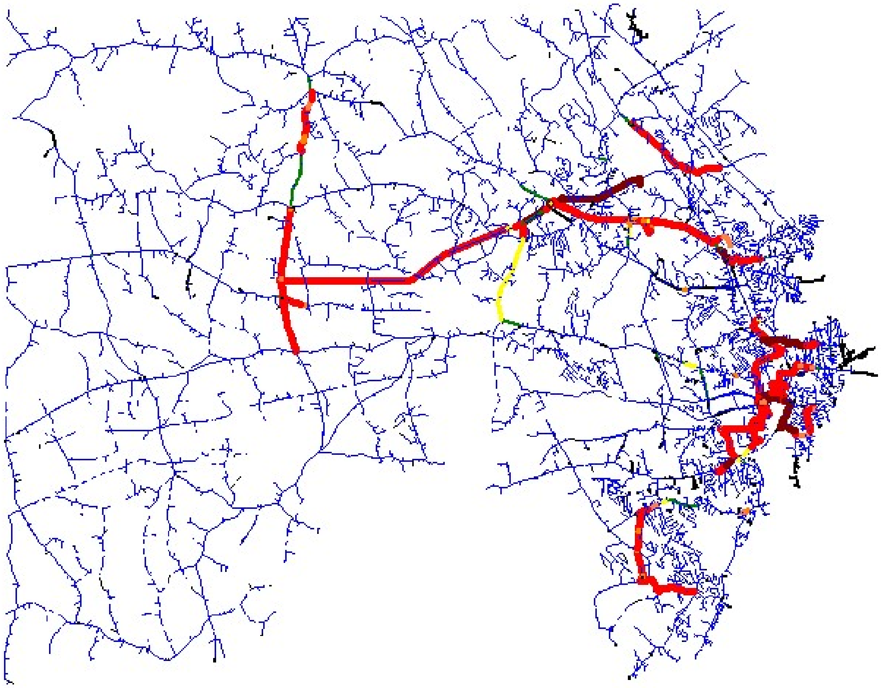
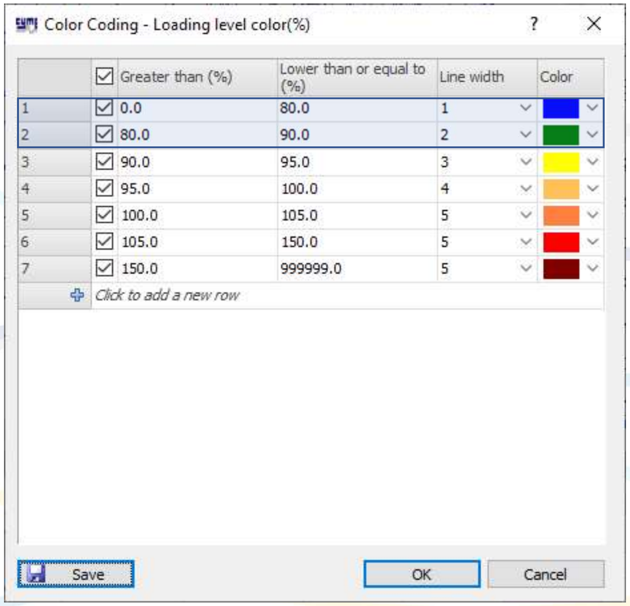
2/24/50 6AM Peak Load Flow Loading





	☑ Greater than (%)	Lower than or equal to (%)	Line width	Color
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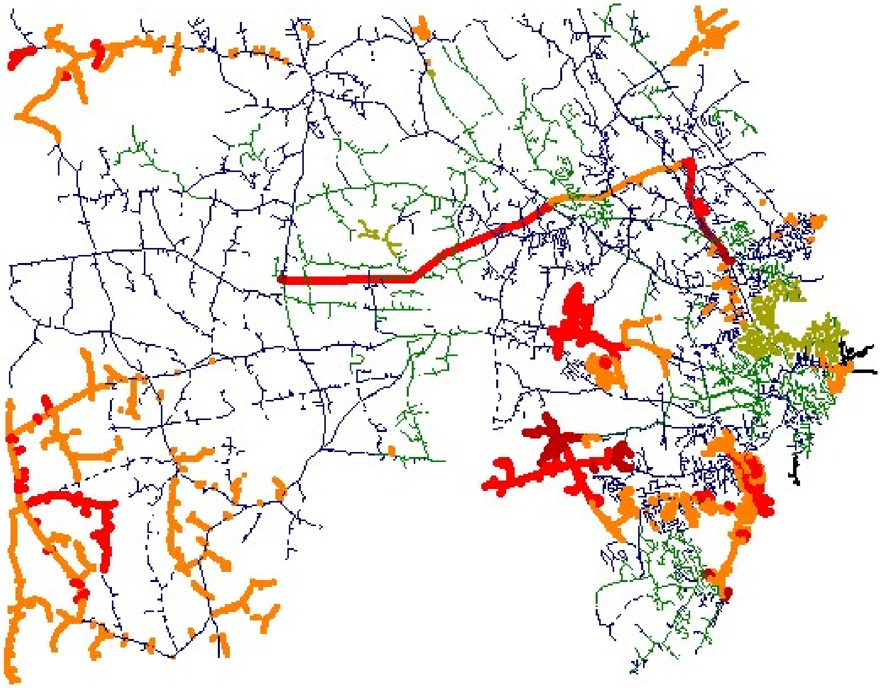
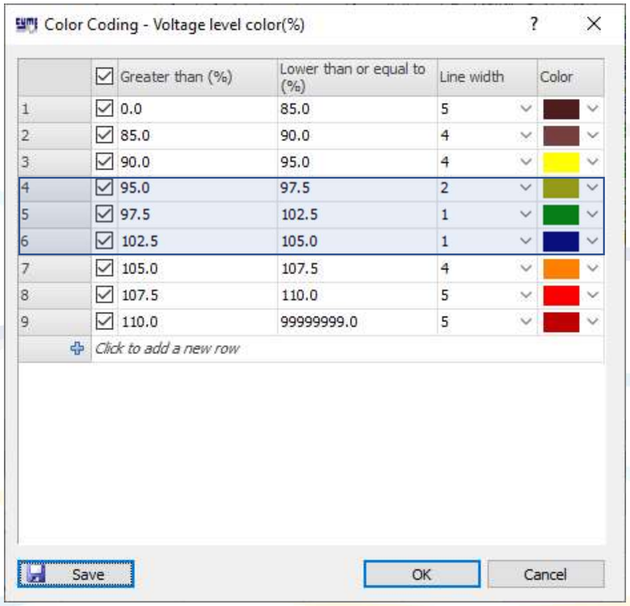
2	☑ 80.0	90.0	2	🟩
3	☑ 90.0	95.0	3	🟨
4	☑ 95.0	100.0	4	🟧
5	☑ 100.0	105.0	5	🟧
6	☑ 105.0	150.0	5	🟥
7	☑ 150.0	999999.0	5	🟫

Click to add a new row

4/16/50 12PM Reverse Peak Load Flow Voltage





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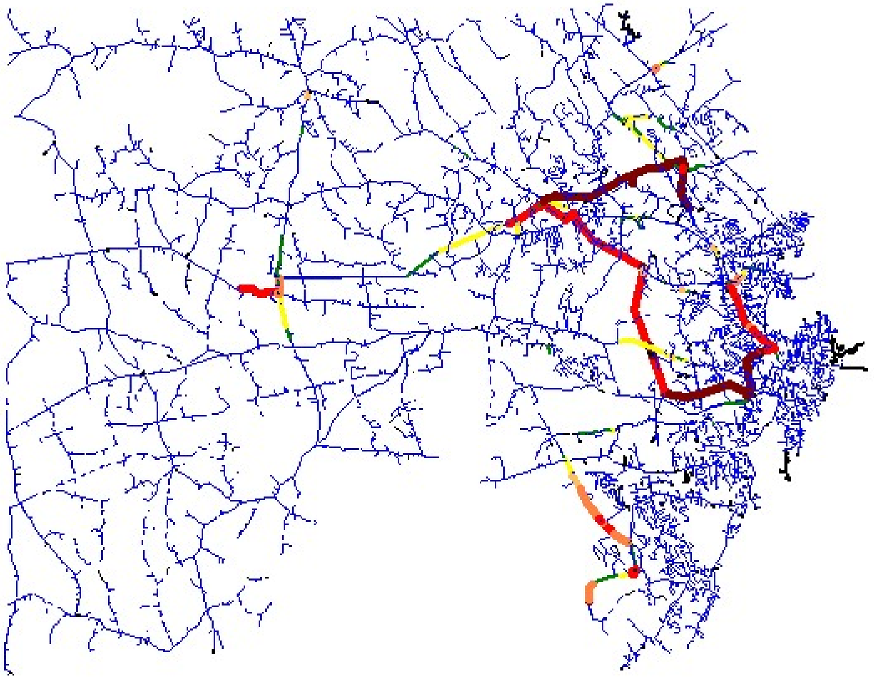
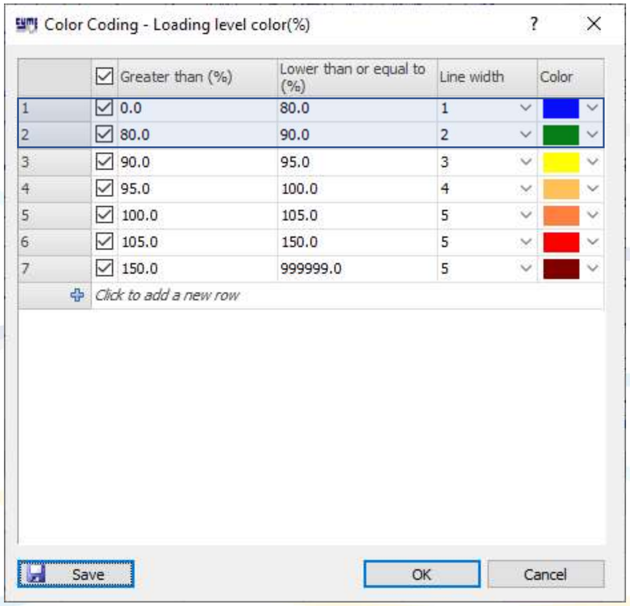
3	☑ 90.0	95.0	4	🟨
4	☑ 95.0	97.5	2	🟩
5	☑ 97.5	102.5	1	🟩
6	☑ 102.5	105.0	1	🟦
7	☑ 105.0	107.5	4	🟧
8	☑ 107.5	110.0	5	🟥
9	☑ 110.0	99999999.0	5	🟥

4/16/50 12PM Reverse Peak Load Flow Loading




Color Coding - Loading level color(%)

	☑ Greater than (%)	Lower than or equal to (%)	Line width	Color
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2	☑ 80.0	90.0	2	🟩
3	☑ 90.0	95.0	3	🟨
4	☑ 95.0	100.0	4	🟧
5	☑ 100.0	105.0	5	🟧
6	☑ 105.0	150.0	5	🟥
7	☑ 150.0	999999.0	5	🟫

4/6/50 12PM Reverse Peak Load Flow Voltage

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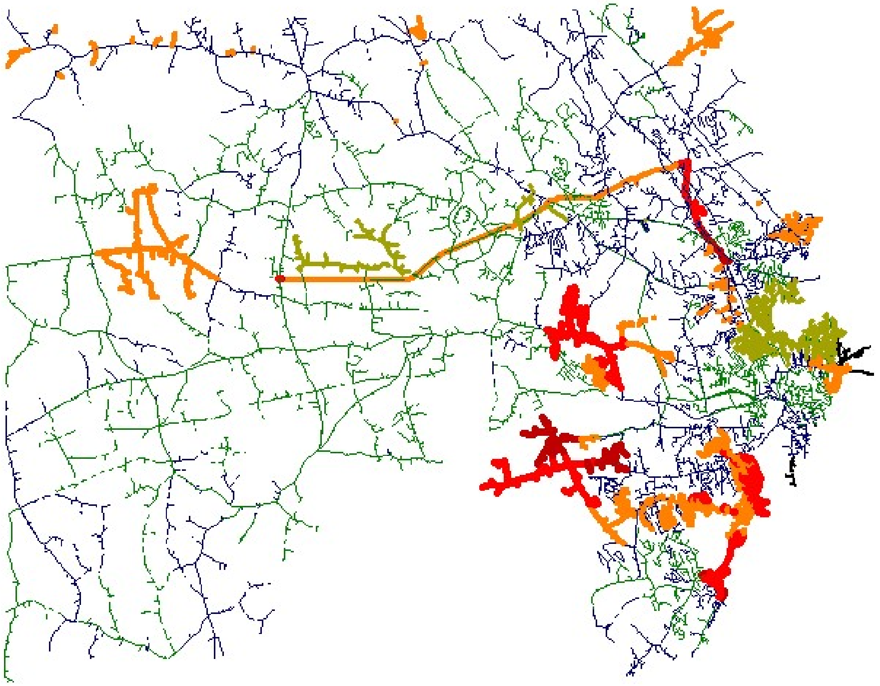
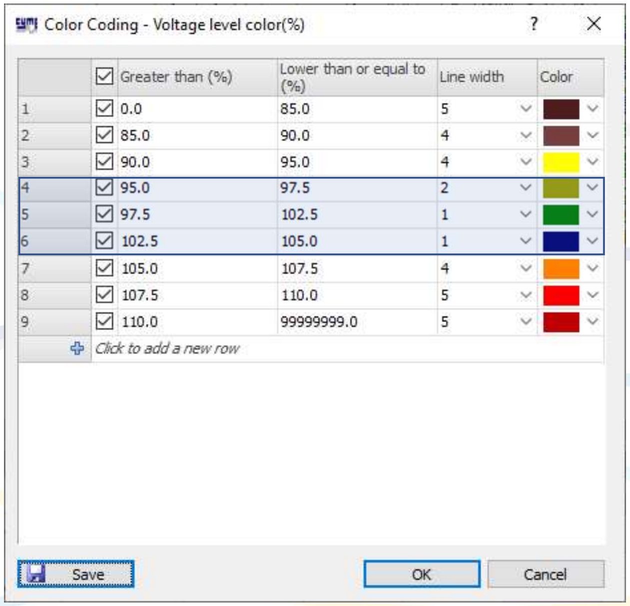


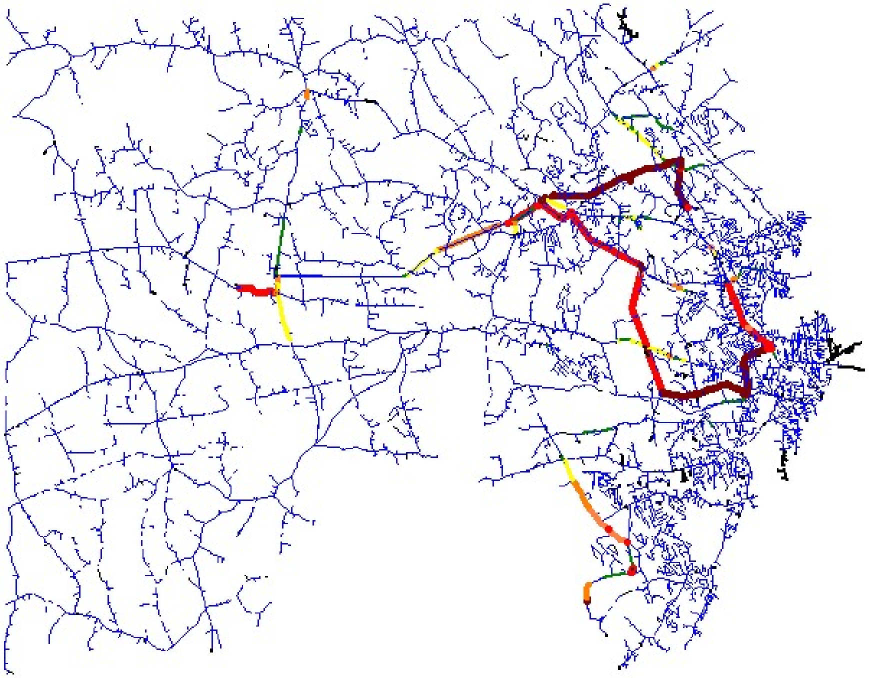


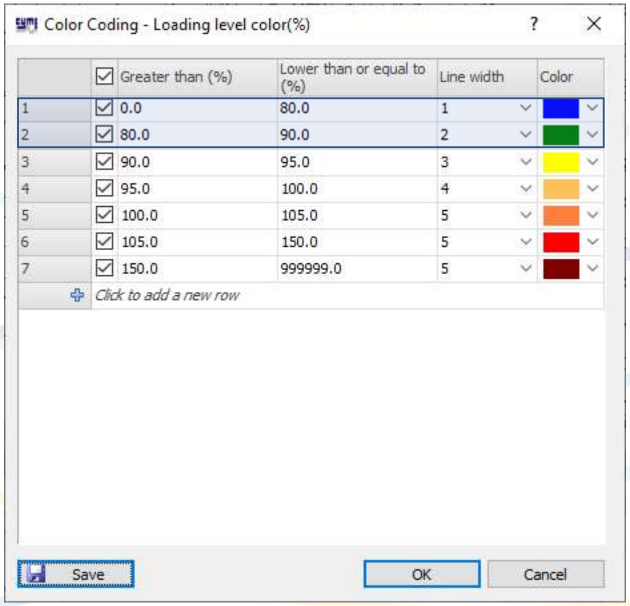
Color Coding - Voltage level color(%)

	☑ Greater than (%)	Lower than or equal to (%)	Line width	Color
1	☑ 0.0	85.0	5	🟫
2	☑ 85.0	90.0	4	🟫
3	☑ 90.0	95.0	4	🟨
4	☑ 95.0	97.5	2	🟩
5	☑ 97.5	102.5	1	🟩
6	☑ 102.5	105.0	1	🟦
7	☑ 105.0	107.5	4	🟧
8	☑ 107.5	110.0	5	🟥
9	☑ 110.0	99999999.0	5	🟥

Click to add a new row

4/6/50 12PM Reverse Peak Load Flow Loading





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2	☑ 80.0	90.0	2	🟩
3	☑ 90.0	95.0	3	🟨
4	☑ 95.0	100.0	4	🟧
5	☑ 100.0	105.0	5	🟧
6	☑ 105.0	150.0	5	🟥
7	☑ 150.0	999999.0	5	🟫

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Key NW Study Findings

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- Distribution operating issues (e.g., **high voltage, protection system coordination**) become more systemic at higher DER penetrations.
- Although there will be some coincidence between commercial "workplace" EV charging and the timing of solar DG injections, there is generally **a mismatch between solar DG injections and typical late day and evening residential EV charging**.
- High levels of renewable DG adoption will impact the grid more significantly during light loading (e.g., off-peak) periods than peak periods. **During light loading periods, significant renewable DG curtailment may be required without GMP investments.**
- High penetrations of DER will significantly impact voltage regulation: EV will lead to more low voltage violations during on-peak periods, and renewable DG injections will lead to more high voltage violations during light loading periods. **Advanced voltage control schemes will be required to manage voltage during both on-peak and light loading periods.**
- Significant **swings in loading and the prevalence of two-way power flows** caused by renewable DG will require more adaptive **relay protection schemes to properly match load to DG,** coordinate circuit breakers to ensure worker safety and the reliable operation of the grid.

Need to address these issues for a reliable, safe electrical system

GMP Strategy, Goals, Approach, Reference Standards, Solutions and ISR Coordination

GMP Strategy, Goals and Approach

Strategy

1. Enable the achievement of Rhode Island Clean Energy Mandates
2. Improve customer service:
    - Improve reliability and safety
    - Maintain / optimize voltage
    - Provide reliable DER interconnections
    - Balance DG and load for stability
3. Apply Grid Modernization
    - Predict failures before they occur, respond faster to incidents and use data to improve operations
    - Automatically restore customers where possible
    - Centralize voltage and power quality management with automated capacitor and regulators, and monitoring/managing DERs
    - Gain visibility and control to operate reliably with forecasted DER penetration
    - Dynamically adapt protection settings based on system configuration
    - Improve capability to detect downed conductors

Goals

- Create voltage visibility, operate within tolerance and optimize control
- Implement VVO/CVR functionality
- Design automatically sectionalization considering reliability, DER penetration, contingency capability, resiliency, and load-DG balance
- Achieve PPL EU reliability level with IEEE definition
- Implement DER Monitoring/Management
- Provide reliable, affordable power that meets objectives

Approach

- Use 2024 ISR for foundational investments
- Use RIE Distribution Study Effort (2030/40/50) to develop ultimate plan, drive priorities and sequencing
- Coordinate with ADMS deployment efforts to align software functionality requirements
- Define transmission, sub-transmission, and substation technology needs to achieve overall strategy
- Review system upgrades alternatives including Transmission, NWA, storage etc. to accommodate new load

Reference Feeder

Feeder is planned, designed, and constructed with highest level of resiliency and reliability, optimized maintenance costs, provides real time operating data, and adjusts dynamically for load changes.

Feeder is fed by Substation with:

- Circuit Breaker high side protection (no fuses, 487E Primary and 751 Backup) & SEL Microprocessor Feeder Relays (751 primary and backup/control)
- Transformer(s) w/ LTC (M-2001D)
- BUS Differential Protection with redundant SEL 487B Relays
- IP SCADA & Fiber Communication

Feeder Characteristics:

- Reliability Driven Construction Standards
    - Class 3 or greater standard pole construction
    - Grade B construction with steel poles
    - Hendrix/UG construction through high vegetation line segments
- Condition/Risk –based data models drive:
    - Pole Inspections
    - Tree Trimming
    - Line Inspections
- Leveraging of Non-Wires Alternates
    - Battery energy storage and other NWA are considered for all constraints
    - DLR devices to understand actual system capacity
    - Management of DER's to enable better power quality

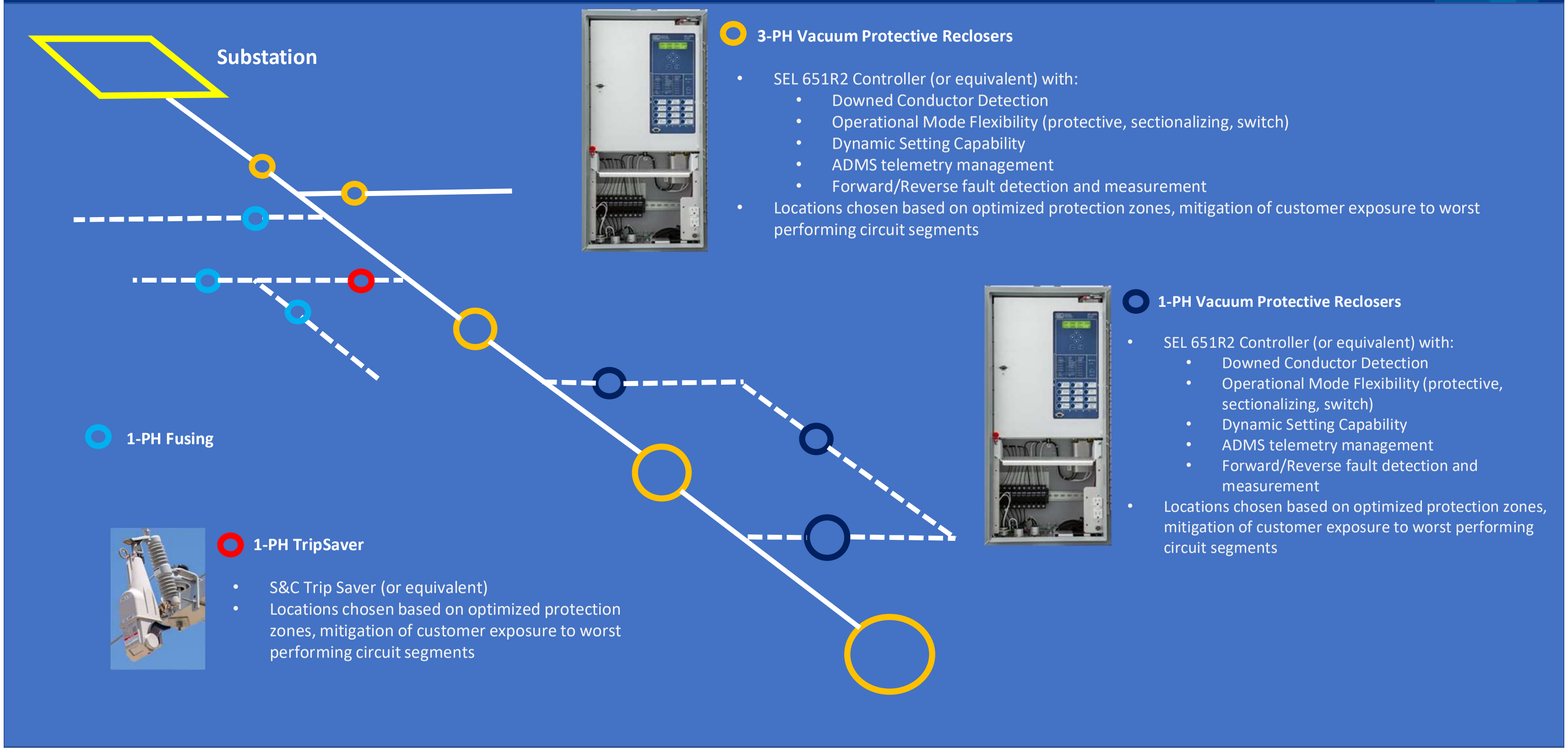
Feeder Characteristics:

- Data driven models driving strategic placement of
    - Telemetered vacuum reclosers w/ SEL relays (651R2) and TripSavers on single and three phase to isolate majority of customers from high-risk segments
    - Telemetered voltage devices to optimize voltage during both peak and light loading (SEL 734B for Cap banks, Beckwith 6200A for Regulators)
    - Feeder ties w/ telemetered reclosers to automatically restore customers (no stranded load)
- Equipped with sensors to locate faults and predict failures
- Downed conductor technology implemented on all smart devices
- Single phase trips to lockout
- Reduced vegetation and vehicle outage exposure due to asset placement
- Eliminated animal exposure
- LTN feeders are equipped with remote switching capability on all network protectors – Standard is Eaton CM-52 with ETI NWP relays

Operational Control:

- Operating system is utilized for
    - Automatic restoration of customers
    - Centralized voltage and power quality management through smart voltage caps and regulators, and behind the meter DERs
    - Dynamically adapt protection settings based on system configuration
    - Control of both single and three phase systems

Reference Feeder – Sectionalizing Equipment



3-PH Vacuum Protective Reclosers

- SEL 651R2 Controller (or equivalent) with:
  - Downed Conductor Detection
  - Operational Mode Flexibility (protective, sectionalizing, switch)
  - Dynamic Setting Capability
  - ADMS telemetry management
  - Forward/Reverse fault detection and measurement
- Locations chosen based on optimized protection zones, mitigation of customer exposure to worst performing circuit segments

1-PH Vacuum Protective Reclosers

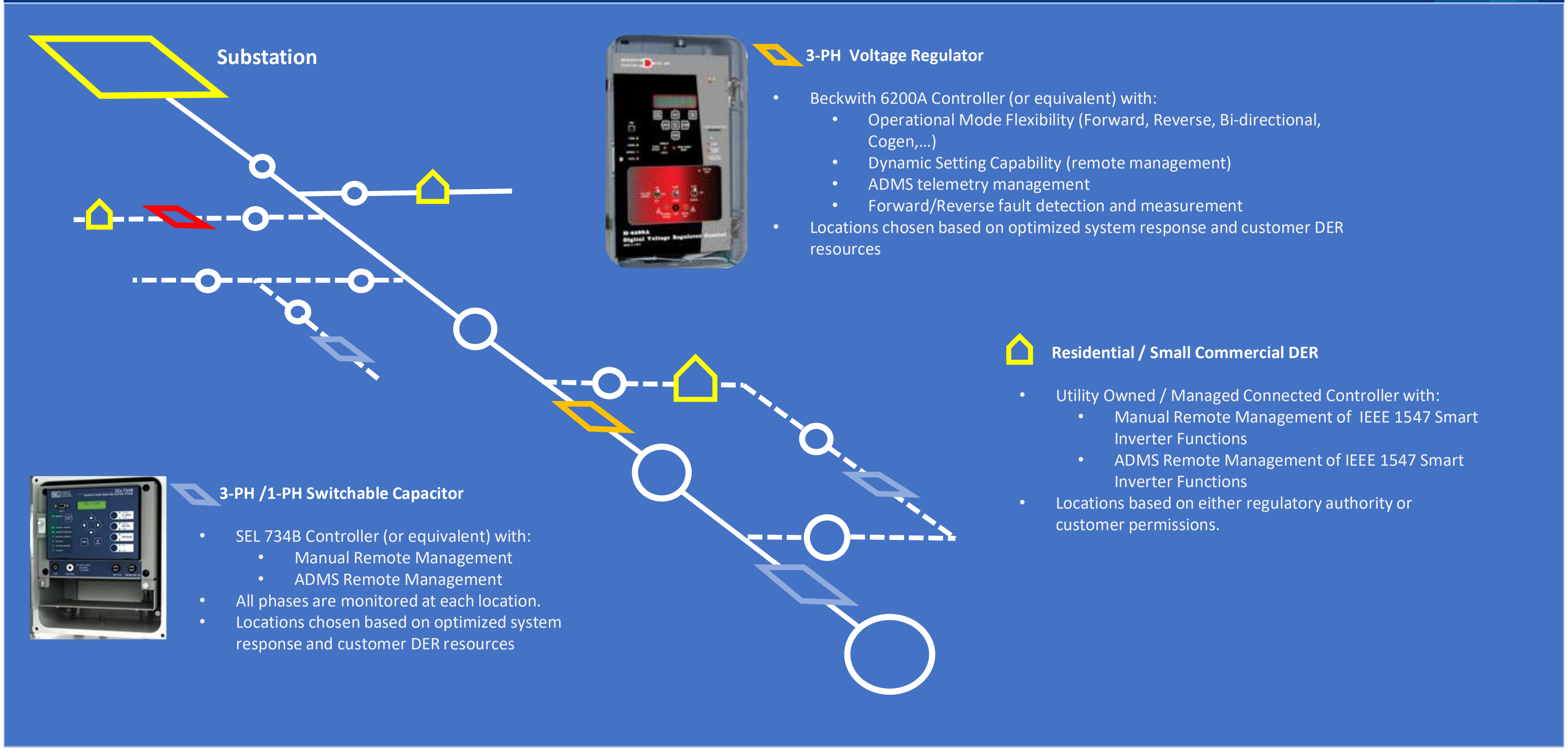
- SEL 651R2 Controller (or equivalent) with:
  - Downed Conductor Detection
  - Operational Mode Flexibility (protective, sectionalizing, switch)
  - Dynamic Setting Capability
  - ADMS telemetry management
  - Forward/Reverse fault detection and measurement
- Locations chosen based on optimized protection zones, mitigation of customer exposure to worst performing circuit segments

1-PH Fusing

1-PH TripSaver

- S&C Trip Saver (or equivalent)
- Locations chosen based on optimized protection zones, mitigation of customer exposure to worst performing circuit segments

Reference Feeder – Volt/VAR Equipment



Substation

3-PH Voltage Regulator

- Beckwith 6200A Controller (or equivalent) with:
  - Operational Mode Flexibility (Forward, Reverse, Bi-directional, Cogen,…)
  - Dynamic Setting Capability (remote management)
  - ADMS telemetry management
  - Forward/Reverse fault detection and measurement
- Locations chosen based on optimized system response and customer DER resources

Residential / Small Commercial DER

- Utility Owned / Managed Connected Controller with:
  - Manual Remote Management of IEEE 1547 Smart Inverter Functions
  - ADMS Remote Management of IEEE 1547 Smart Inverter Functions
- Locations based on either regulatory authority or customer permissions.

3-PH /1-PH Switchable Capacitor

- SEL 734B Controller (or equivalent) with:
  - Manual Remote Management
  - ADMS Remote Management
- All phases are monitored at each location.
- Locations chosen based on optimized system response and customer DER resources

Reference T / Sub T Radial Line

- The Reference Sub-T radial line standard calls for future functionality from a variety of monitoring, control and protection devices in substations and on the lines feeding them.
- Examples include:
  - Circuit Breaker monitoring
  - Dynamic line rating monitors
  - Transformer and bushing monitoring
  - Battery monitoring
  - Transmission Cap Bank Primary Relay + Backup and Control Relay
  - Cap Bank String Monitoring
  - Primary line relay
  - Line Protection and Control relay (to optimize protection zones, mitigate customer exposure)
  - Capacitor Voltage Transformer / Potential Transformer monitoring
  - Relay-to-Relay communications (Ring and Direct)
  - EUNet IP based SCADA communication switches and routers

Rhode Island Energy SAIFI Reliability Comparative Analysis

Reliability Comparative Analysis

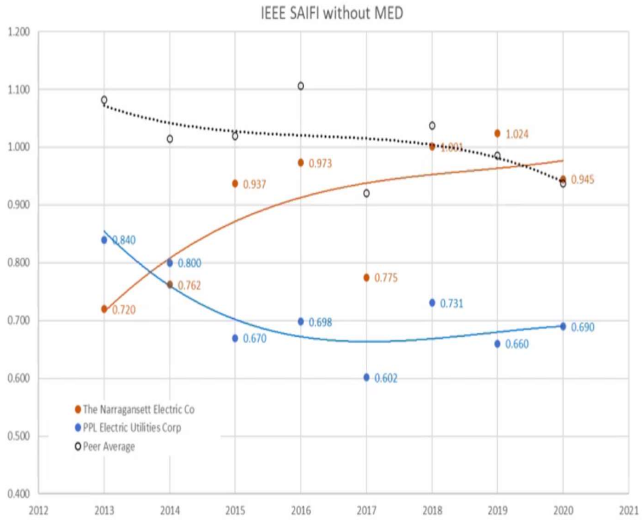
- Compares RIE, PPL EU and Peer Group
- Based upon IEEE Standard
- Included nine peers with >300K electric customers in a similar geography that report 5-minute SAIFI
- Time frame → 2013 – 2020 (2021 data is not available yet)

Conclusion: RIE SAIFI lags when compared to peers and to PPL EU.

- Peers reduced SAIFI by 15%
- PPL EU has reduced SAIFI by 22%
- RIE has increased (worse) SAIFI by 5%

Approach: Plan FLISR deployment in two phases:

- Complete study to plan for ultimate recloser build-out that includes reliability, DG to load needs and reconfiguration.
- Phase 1: Install initial reclosers in the immediate ISR years.
- Phase 2: Build ultimate FLISR scheme



Reliability - Voltage

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Current Situation:

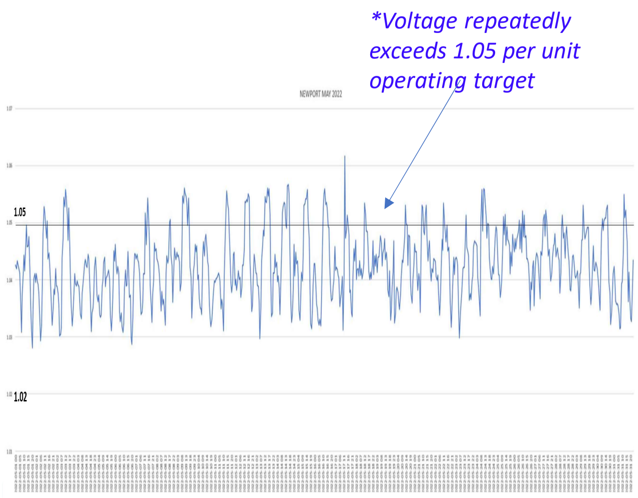
- DERs cause voltage swings and introduce voltage violations during high and low load conditions

Goal:

- See and maintain voltage within +/- 5%
- Successfully operate and manage with increased DER
- Create wherewithal to "fine tune" voltage control through VVO

Approach

- Gain near-time visibility of feeder voltage profile to understand when and where violations are occurring
- Upgrade and install automated capacitors and regulators to better manage voltage
- Coordinate with ADMS Base and development to include VVO and DER Monitor / Manage
- Execute in phases
  - Phase 1: automated capacitors and regulators by end of 2024 per study results
  - Phase 2: Expand capacitors and regulator automation considering studies and Reference Feeder criteria
  - Phase 3: Implement VVO targeting the initial launch in 2026
  - Phase 4: Implement DER Monitor / Manage



*Voltage repeatedly exceeds 1.05 per unit operating target

3,000 kW Solar DG nominal voltage output in RIE Newport Region - May 2022

Required to maintain ±5% of nominal voltage ie 0.95 to 1.05 per unit voltage.

System Enhancements Being Studied

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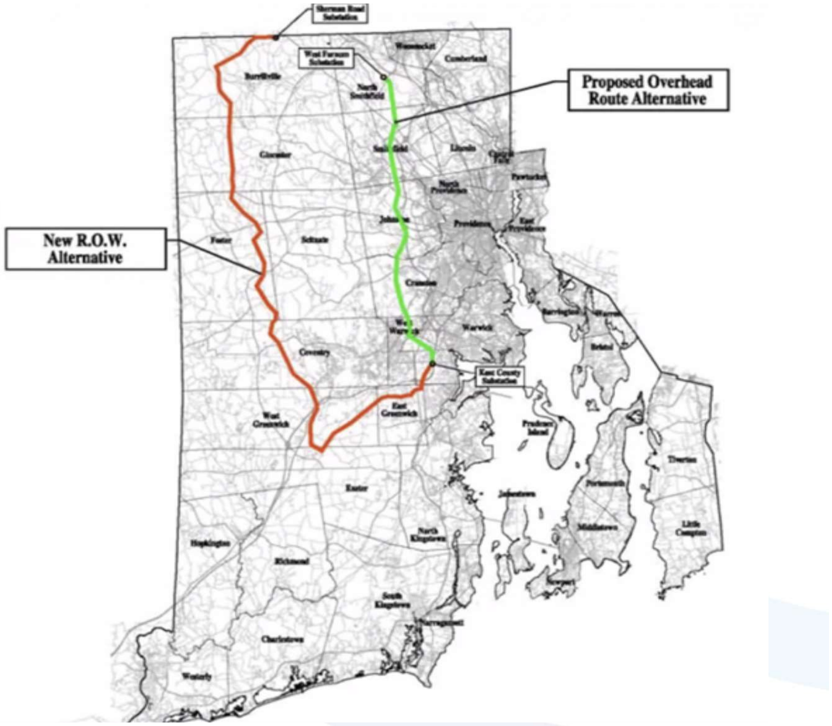
Recognizing there is a significant increase in load over the period and more flexibility is needed…

- Reviewing system alternatives that can accommodate most economically
- Transmission alternatives that are being studied are shown (preliminary)
- Many potential benefits to Rhode Island

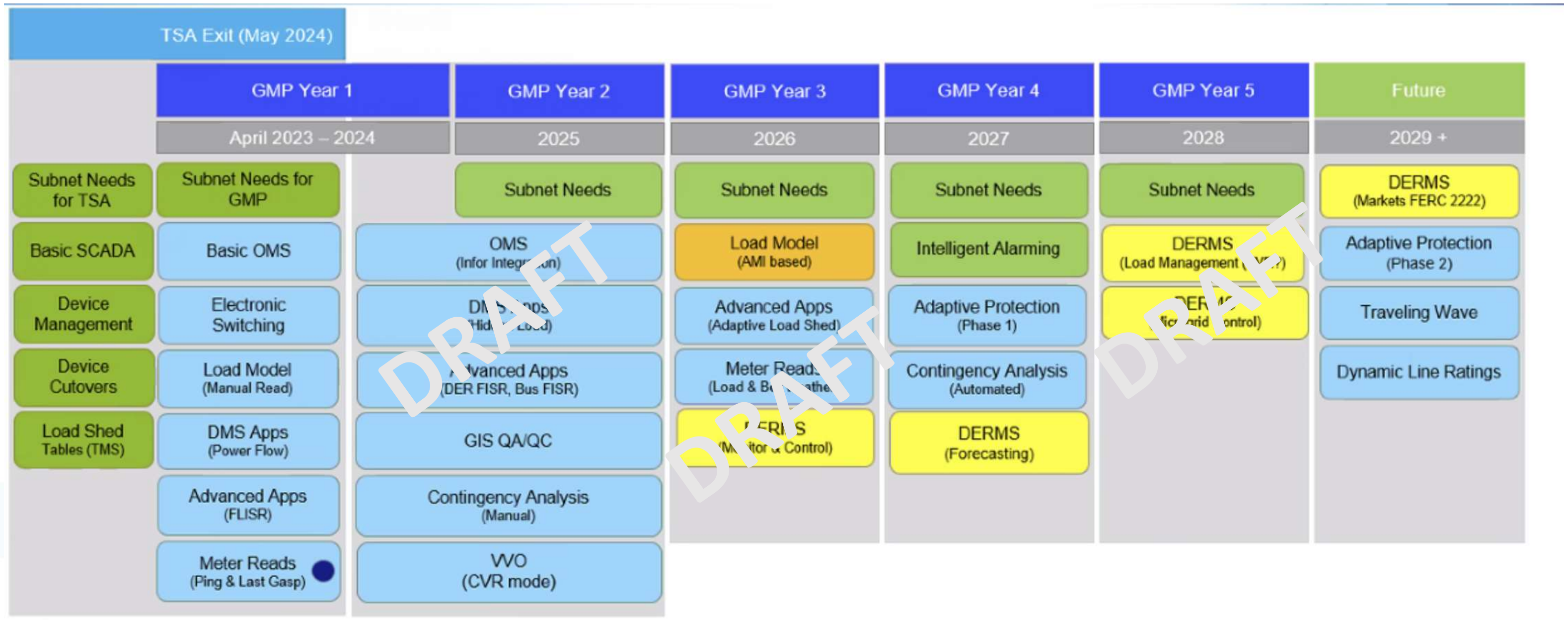


GMP Cost Estimates and ISR Coordination

- Five-year cost estimates for each GMP solution will be provided
- High Distributed Energy Resource (DER) and Low DER customer adoption scenarios will be analyzed
- GMP cost estimates include all the costs of deploying the grid modernization solutions
- GMP and AMF will be coordinated where there are interdependencies
- ADMS basic has been included with the PPL acquisition
- Investments in AMF, Advanced Field Devices (i.e., Feeder Monitoring Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers), and Operational Telecommunications, are the primary cost drivers
- GMP costs would be recovered through the Company’s annual ISR filings as adjusted to the PPL calendar year assumed as follows:
  - ISR 2024 = Apr 2023 – Dec 2024
  - ISR 2025 = Jan 2025 – Dec 2025
  - ISR 2026 = Jan 2026 – Dec 2026
  - ISR 2027 = Jan 2027 – Dec 2027
  - ISR 2028 = Jan 2028 – Dec 2028
- Future costs anticipated after ISR 2028 will be discussed and estimated.

- ISR 2024 and the GMP will be coordinated
- Both to be filed in Dec 2022

Preliminary GMP Software Functionality Chart (ADMS and More)



TSA Exit (May 2024)						
	GMP Year 1	GMP Year 2	GMP Year 3	GMP Year 4	GMP Year 5	Future
	April 2023 – 2024	2025	2026	2027	2028	2029 +
Subnet Needs for TSA	Subnet Needs for GMP	Subnet Needs	Subnet Needs	Subnet Needs	Subnet Needs	DERMS (Markets FERC 2222)
Basic SCADA	Basic OMS	OMS (Infor Integration)	Load Model (AMI based)	Intelligent Alarming	DERMS (Load Management ([illegible]))	Adaptive Protection (Phase 2)
Device Management	Electronic Switching	DMS Apps (Hide Load)	Advanced Apps (Adaptive Load Shed)	Adaptive Protection (Phase 1)	DERMS (Microgrid Control)	Traveling Wave
Device Cutovers	Load Model (Manual Read)	Advanced Apps (DER FISR, Bus FISR)	Meter Reads (Load & Bellwether)	Contingency Analysis (Automated)		Dynamic Line Ratings
Load Shed Tables (TMS)	DMS Apps (Power Flow)	GIS QA/QC	DERMS (Monitor & Control)	DERMS (Forecasting)		
	Advanced Apps (FLISR)	Contingency Analysis (Manual)				
	Meter Reads (Ping & Last Gasp) ●	VVO (CVR mode)				

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Appendix

Acronyms

- ADMS = Advanced Distribution Management System
- AESC = Avoided Energy Supply Cost
- AMF = Advanced Meter Functionality
- AMI = Advanced Meter Infrastructure
- AMR = Automatic Meter Reading
- ASA = Amended Settlement Agreement
- ASHP = Air Source Heat Pump
- BAU = Business as Usual
- BCA = Benefit Cost Analysis
- C&I = Commercial and Industrial
- CEP = Customer Engagement Plan
- CGR = Connected Grid Router
- CO2 = Carbon Dioxide
- CP = Customer Portal
- CPP = Critical Peak Pricing
- D = Distribution
- DCFC = Direct Current Fast Charging
- DER = Distributed Energy Resource
- DERMS = Distributed Energy Resource Management System
- DG = Distributed Generation
- DLM = Dynamic Load Management
- DPAM = Distribution Planning & Asset Management
- DPL = Dayton Power and Light
- DR = Demand Response
- DRIPE = Demand Reduction Induced Price Effect
- DSCADA = Distributed Supervisory Control and Data Acquisition
- EC4 = Executive Climate Change Coordinating Council
- EE = Energy Efficiency
- EDI = Electronic Data Interchange
- EHP = Electric Heat Pump
- EIA = Energy Information Administration
- EPO = Energy Profiler Online
- ESB = Enterprise Service Bus
- EV = Electric Vehicle
- FAN = Field Area Network
- FLISR = Fault Location Isolation and Service Restoration
- GBC = Green Button Connect
- GBD = Green Button Download my data
- GHG = Greenhouse Gas
- GIS = Geographical Information Systems
- GMP = Grid Modernization Plan
- HAN = Home Area Network
- HCA = Hosting Capacity Analysis
- HES = Head End System
- HVAC = Heating, Ventilation, and Air Conditioning
- ICAP = Installed Capacity
- ICE = Interruption Cost Estimate
- IoT = Internet of Things
- IP = Internet Protocol
- ISA = Interconnection Service Agreement
- ISO NE = Independent System Operator New England
- IT = Information Technology
- KY = Kentucky
- LDV = Light Duty Vehicle
- LVA = Locational Value Analysis
- MA = Massachusetts
- MDM = Meter Data Management
- MV/LV = Medium Voltage/Low Voltage
- NEM = Net Energy Metering
- NMPC = Niagara Mohawk Power Corporation
- NPP = Non-Regulated Power Producer
- NY = New York
- NWA = Non-Wires Alternative
- OER = RI Office of Energy Resources
- OMS = Outage Management Systems
- PA = Pennsylvania
- PBR = Performance-Based Regulation
- PI Historian = Plant Information Historian
- PIM = Performance Incentive Mechanism
- PLC = Power-Line Communication
- PPL = Pennsylvania Power and Light
- PSE&G = Public Service Electric & Gas
- PSR = Platform Service Revenue
- PST = Power Sector Transformation
- PUC = Public Utilities Commission
- PV = Photovoltaic
- REC = Renewable Energy Credit
- REV = Reforming the Energy Vision
- RF = Radio Frequency
- RGGI = Regional Greenhouse Gas Initiative
- RI = Rhode Island
- RIE = Rhode Island Energy
- RMD = Residential Methane Detector
- RTP = Real Time Pricing
- RTU = Remote Terminal Unit
- SaaS = Software as a System
- SCT = Societal Cost Test
- SME = Subject Matter Expert
- ToC = Table of Contents
- TOU = Time Of Use
- TSA = Transition Service Agreement
- TVR = Time Varying Rate
- VDER = Value of Distributed Energy Resources
- VMT = Vehicle Miles Traveled
- VPP = Variable Peak Pricing
- VVO/CVR = Volt-Var Optimization/Conservation Voltage Reduction
- WACC = Weighted Average Cost of Capital

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Grid Modernization Plan: Model Demonstration

Power Sector Transformation – October 7, 2022

Agenda

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- Schedule Update
- Purpose of Meeting
- Study scope and approach
- Grid Modernization Plan Model Demonstration
- Key Takeaways

PST Ground Rules:

- Ask questions and provide feedback as we go
- Raise hand and state name when asking questions
- One conversation at a time
- Timekeeper to monitor discussion and align to agenda
- Topics and questions scheduled for future discussion will be saved in the Parking Lot

PST Advisory Collaboration: Recap and Schedule Update

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PST Advisory AMF & GMP Subcommittee Meetings and Preliminary Agendas

Stakeholder Collaboration (i.e., Subcommittee meetings and discussions)

Obtain Feedback and Seek Alignment on Proposals and Approaches

Review Initial, Refined and Final Proposals

Jun 21, 2022

- **RI Division and OER Meeting**
- Introductions
- Proposed timeline
- Preliminary agenda for PST meetings
- AMF Introduction and overview of key areas
- GMP Introduction and coordination

July 14, 2022

- **PST Advisory Meeting**
- Introductions
- PPL Background and Experience
- Full Scale Enabling Platform
- Detailed Deployment Plan
- Functionality Timing
- ASA coverage
- AMF cost review
- GMP study scope and approach
- GMP forecast analysis

Aug 2, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Customer Engagement Plan
- AMF Opt-out
- AMF Customer value streams
- AMF Auto-notification
- AMF Benefits

Aug 16, 2022

- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Data access, privacy, governance
- AMF Cyber Security
- AMF Cost and Benefit Recap
- Cost Recovery and Revenue Requirements
- GMP scenario analysis
- GMP solution development
- GMP ISR Coordination plans

Sept 1, 2022

- **PUC Technical Session**

Oct/Nov 2022

- **File AMF**
- **AMF includes Business Case, Testimonies and BCA**
- **Coordinates with GMP execution plan and BCA**

Oct 7, 2022

- Grid Modernization Plan Model Demonstration

Nov 9, 2022

- PST Advisory Meeting
- Prior meeting will drive agenda
- GMP Alternative recommendation
- GMP BCA review

December 2022

- **File GMP**
- GMP Includes Business Case, Testimonies and BCA
- Coordinate with ISR and AMF details

AMF – Advanced Metering Functionality
GMP – Grid Modernization Plan
BCA – Benefit-Cost Analysis

September 2022
AMF Targeted Filing Date

December 2022
GMP Targeted Filing Date

🟦 Initial alignment meeting with RI Division and OER
■ PST Advisory Sub-Committee Meeting AMF
🟩 PST Advisory Sub-Committee Meeting GMP
🟥 PUC Technical Session

Introductions, Objectives and Background

Purpose

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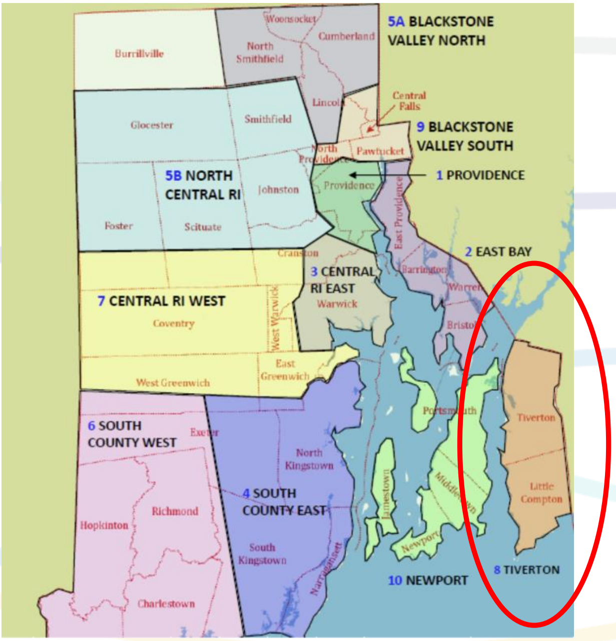
- Following up from a PST request to see the GMP model
  - Using one planning area, Tiverton, as an example
  - Applying load and DER forecast through 2050
- Objective
  - Share the study and modeling approach
  - Provide a preview of the system implications resulting from the long-term forecast that define GMP investment requirements and the urgency to make them
  - Address questions, collect feedback

Tiverton Planning Area



Study Scope

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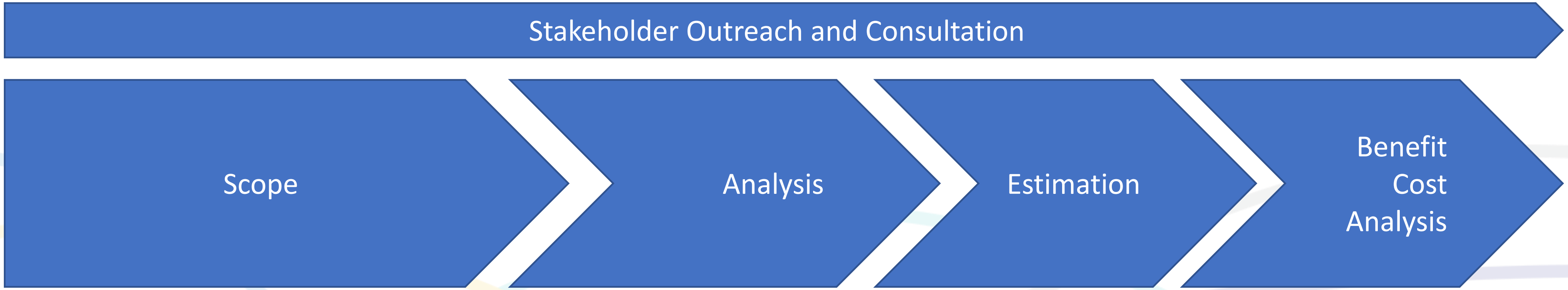

State-wide 8760 analysis

- ✓ 400 feeders
- ✓ Includes area study recommendations
- ✓ Sub-transmission modeling and testing (Constable)
- ✓ System-wide transmission analysis (Ali)

Years: 2030, 2040, 2050 – Aligned with Act on Climate

Forecast: Base, Low, High DER

Issue Identification:

- ✓ Determine load, voltage and protection issues (Constable)
- ✓ Determine areas with degrading reliability (Eline)
- ✓ Consider resiliency needs

Solutions:

- Optimal Recloser Installation
- No GMP vs With GMP

Sensitivities:

- Transmission

Road Map:

- Device Deployment Plan (Constable)
- ✓ Functionality Availability

(Menges)

Estimation:

- Equipment Costs
- Installation Costs

Leverage PPL experience

- ✓ Actual Costs
- ✓ Installation Assumptions
- ✓ Standards

BCA:

- Comply with Docket 4600
- Update with PPL experience, Study and Reliability findings

Transition Component:

- ADMS 'Basic' came with the acquisition

Business Plan

- Write Business Case
- Write Testimony

Approach to Distribution System Analysis – Modeling Demo

- State-wide analysis to determine the most efficient plan to meet the state's energy policy, growing resiliency and reliability needs, and customer's expectations.
- Scope
  - State-wide distribution analysis
    - ~400 feeders
    - Sub-transmission modeling and testing
    - Traditional area study recommendations included in models
  - Analysis years – 2030, 2040, 2050 to align with Act on Climate target years
  - Cases
    - No Grid Modernization – build for extremes
    - Grid Modernization – manage away extremes
  - 8760-Hour per year analysis
- Analysis
  - Issue Identification
    - Determine load and voltage issues across hours of the year
  - Case Evaluation
    - No GMP – Base DER Forecast - How would traditional utilities alternatives solve the issues?
    - GMP – Base DER Forecast - How would GMP-type alternatives solve the issues?

Forecast / Impact to Peak Demand: A Review

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Key DER Metrics for Milestone Study Years

	GMP DER Forecast Analysis -- Impact to Peak Demand					
	<u>2030</u>		<u>2040</u>		<u>2050</u>	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps, MW	0	200	5	1310	5	2825
# Heat Pumps	54,000	54,000	325,000	325,000	400,000	400,000
Solar PV, MW	0	0	0	0	0	0
Solar PV, nameplate MW	1500	1500	3400	3400	5000	5000
EV Charging, MW	70	80	805	910	1010	238
# Electric Vehicles	87,300	87,300	675,000	675,000	840,000	840,000
RIE Peak Demand, MW	1940	1415	2590	3280	2785	3855

GMP Model Demonstration – Model Setup

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- Base Model – as used with typical planning studies
  - Existing distributed generation confirmed
- Forecasted load, generation, electric vehicles, heating (heat pumps) added
  - Load forecast with energy efficiency incorporated into load profiles
  - Generation added to the model explicitly
    - General distribution PVs added as 100kW sites
    - Specific PV and Wind sites added to subtransmission
    - Generation load cycles are based on PVWatts and actual data
  - Electric vehicles and heat pumps added as customer load types to existing load sites
    - Electric vehicle load cycle based on EVI-Pro-Lite
    - Heating pump load based on industry research and 2015 weather year

GMP Model Demonstration – Tiverton Example

- Area Study recommendations added
- Forecast details show in table below
  - Generation allocated by load
  - Electric vehicles and heat pumps allocated by customers

Substation Name	Feeder Number	MW DG 2030	MW DG 2040	MW DG 2050	2040 Manual DG Allocation	2050 Manual DG Allocation	Existing Onshore Wind	Onshore Wind 2030	Onshore Wind 2040	Onshore Wind 2050	EVs 2030	EVs 2040	EVs 2050	EV MWs 2030	EV MWs 2040	EV MWs 2050	EHPs 2030	EHPs 2040	EHPs 2050	EHP MWs 2030	EHP MWs 2040	EHP MWs 2050
TIVERTON	33F1	7.72	14.84	14.84							465	3594	4488	0	5	6	272	1718	2148	2	12	15
TIVERTON	33F2	7.00	14.63	14.63							491	3799	4745	0	5	6	288	1816	2271	2	13	16
TIVERTON	33F3	3.53	10.40	10.40							516	3993	4987	0	5	7	302	1909	2387	2	13	17
TIVERTON	33F4	5.55	12.87	12.87							542	4192	5235	0	6	7	317	2004	2506	2	14	18

Guide to Analysis Slides

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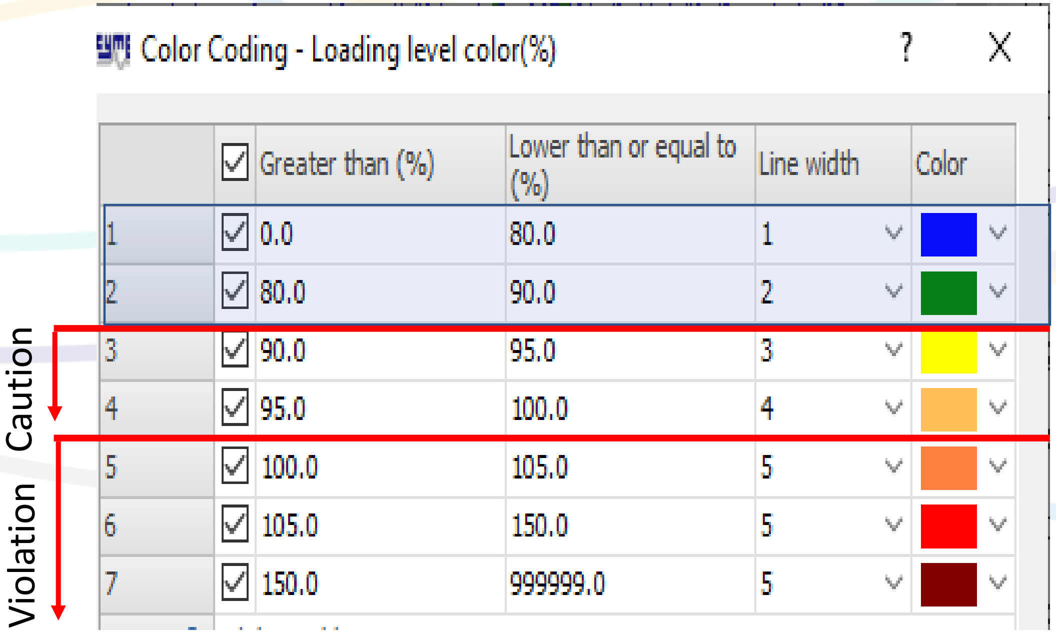
- Each test year will be shown with loading and voltages analysis
  - Cool colors are shaded and have no issues ▭
  - Warm colors are issues

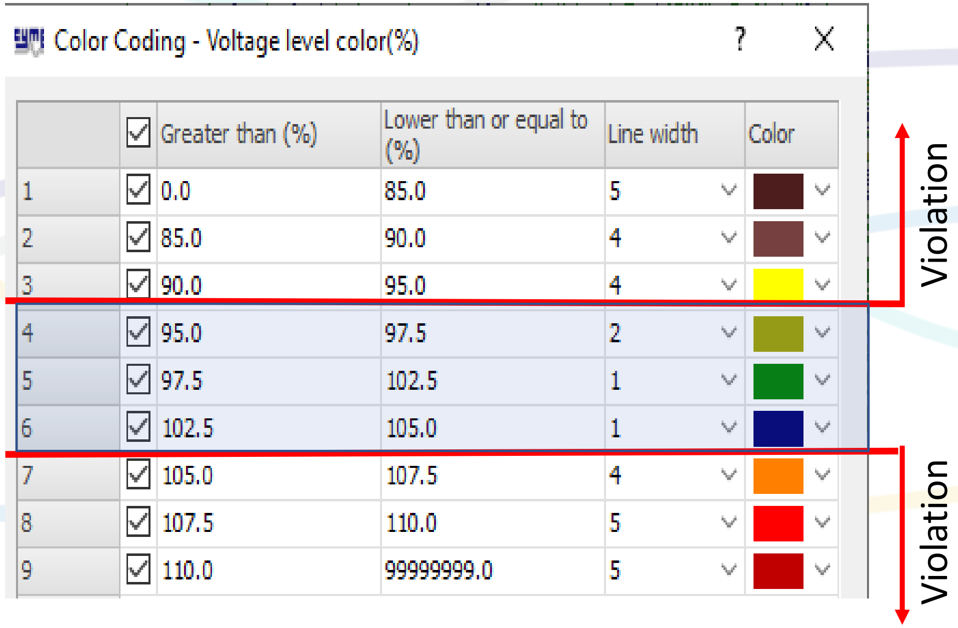
Loading Color Legend



Color Coding - Loading level color(%)

	☑ Greater than (%)	Lower than or equal to (%)	Line width	Color
1	☑ 0.0	80.0	1	🟦
2	☑ 80.0	90.0	2	🟩
3	☑ 90.0	95.0	3	🟨
4	☑ 95.0	100.0	4	🟧
5	☑ 100.0	105.0	5	🟧
6	☑ 105.0	150.0	5	🟥
7	☑ 150.0	999999.0	5	🟫

Voltage Color Legend



Color Coding - Voltage level color(%)

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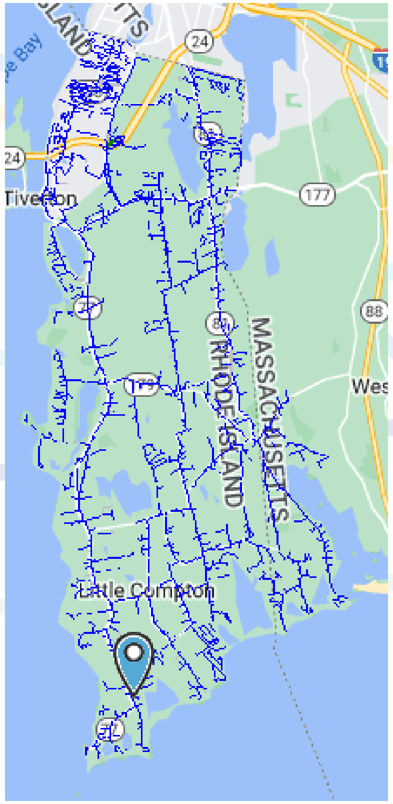
3	☑ 90.0	95.0	4	🟨
4	☑ 95.0	97.5	2	🟩
5	☑ 97.5	102.5	1	🟩
6	☑ 102.5	105.0	1	🟦
7	☑ 105.0	107.5	4	🟧
8	☑ 107.5	110.0	5	🟥
9	☑ 110.0	99999999.0	5	🟥

Post Study Area Recommendations - Tiverton

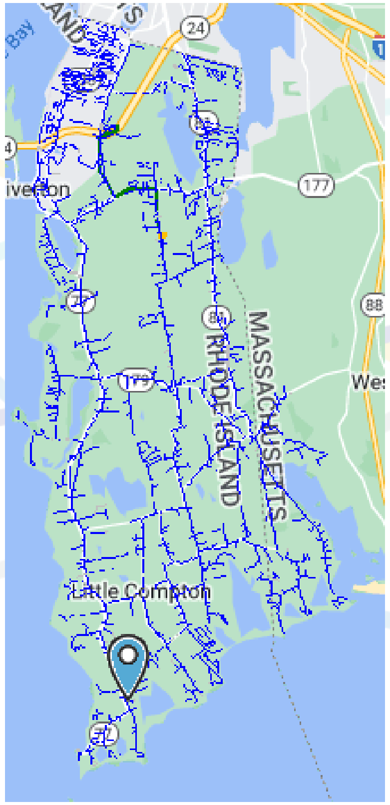
- After study recommendations – new feeder

Loading

7/22/2025 6PM

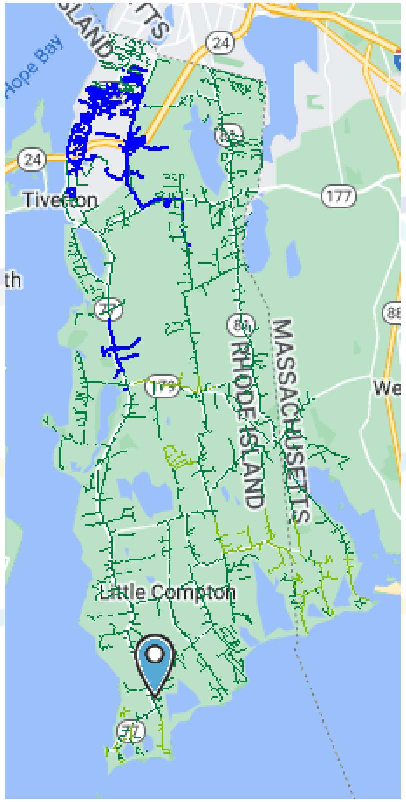


4/16/2025 11AM

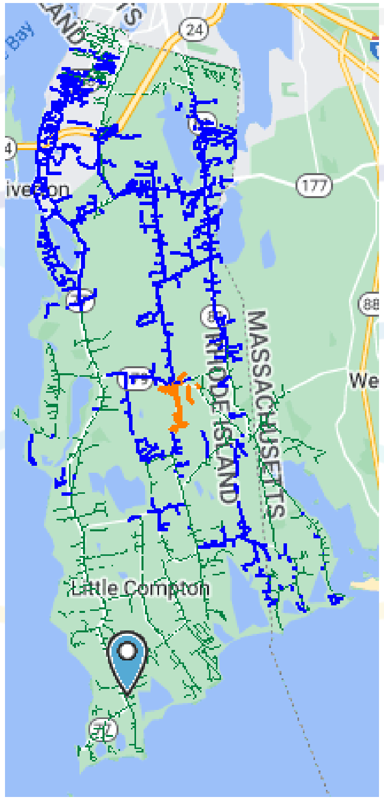


Voltage

7/22/2025 6PM



4/16/2025 11AM

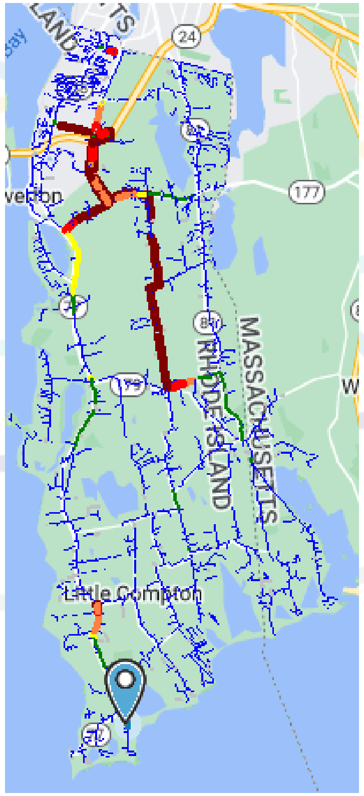


2040 GMP - Tiverton

- 2040 load, DG, EV, EHP levels, Winter Peaking

Loading

2/13/2040 6PM



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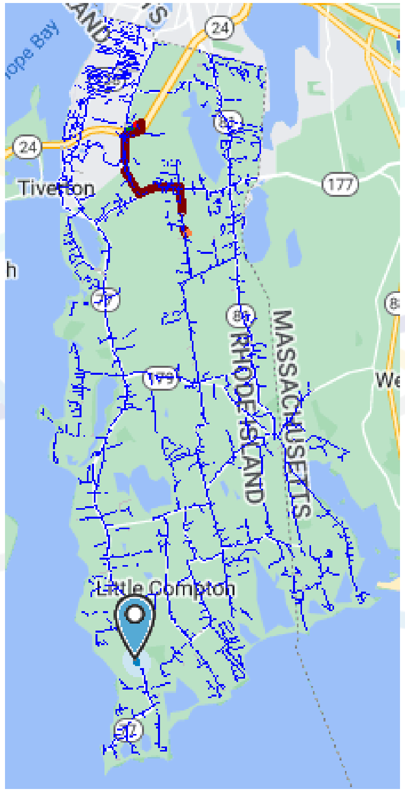
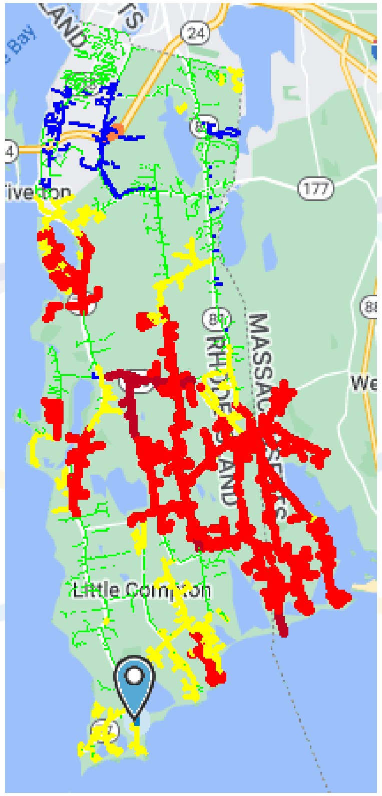


Voltage

2/13/2040 6PM



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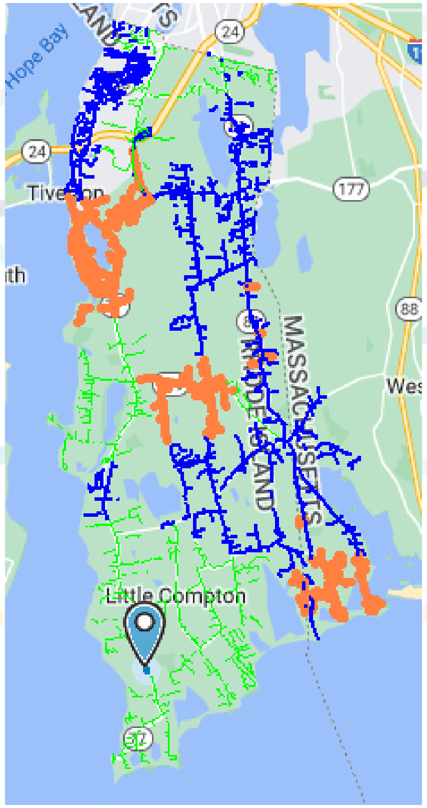
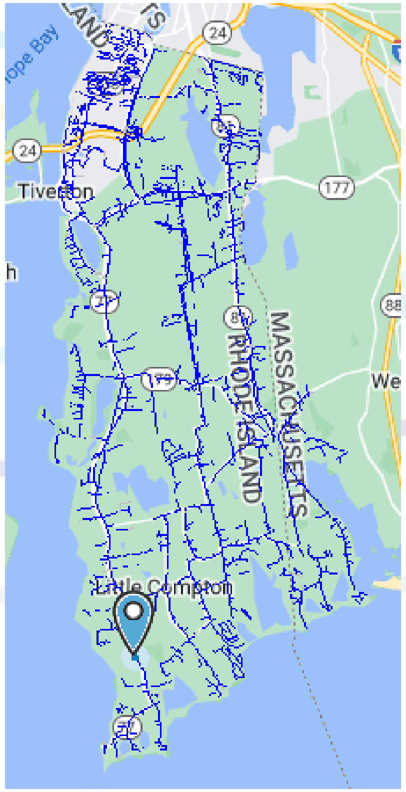


2040 GMP – Tiverton – Non GMP Fixes

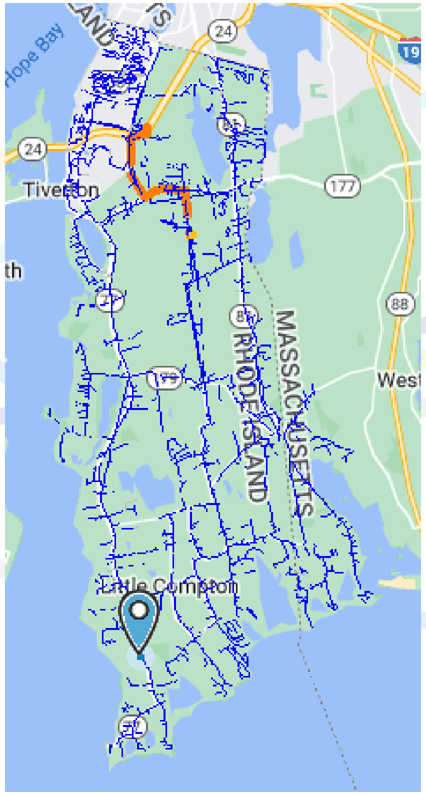
- 3 new feeders added to existing station, second substation with 2 new feeders added

Loading

2/13/2040 6PM

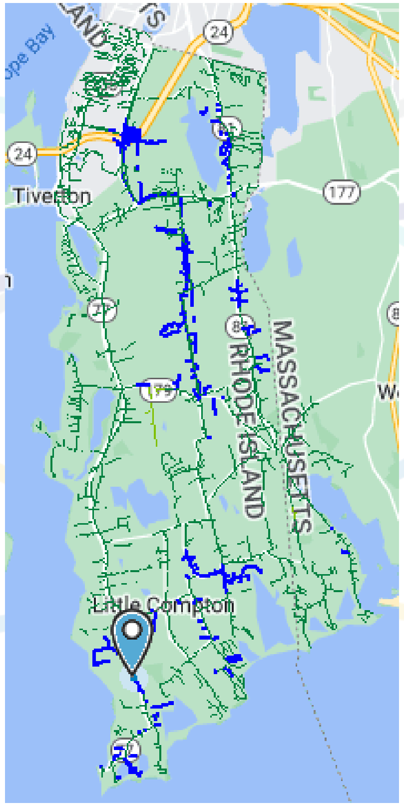


4/16/2040 11AM

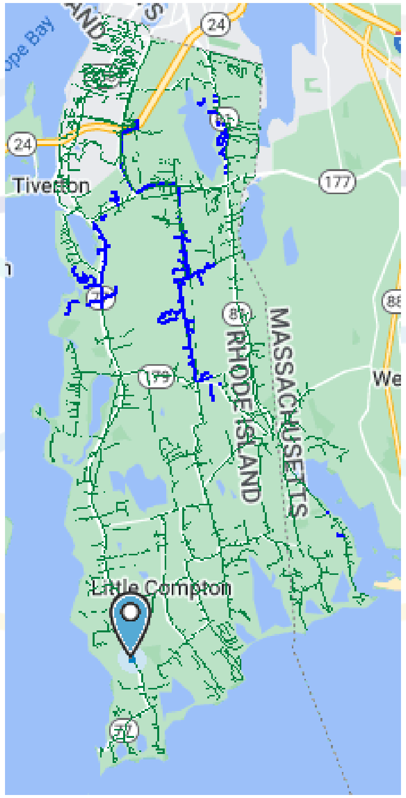


Voltage

2/13/2040 6PM



4/16/2040 11AM



2040 GMP – Tiverton – GMP Fixes

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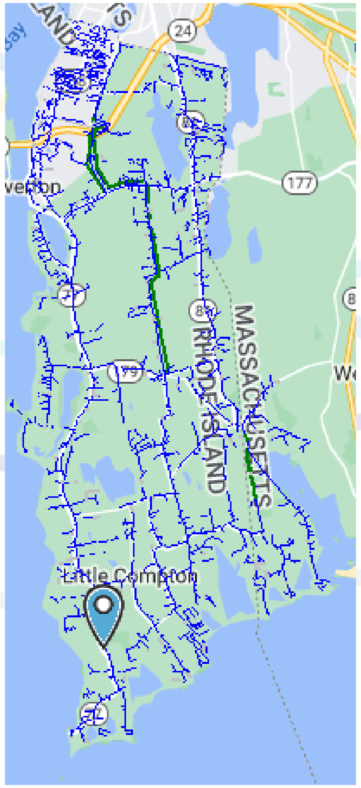
- Load and generation shifts, 2 new feeders, 4 BESS sites

Loading

2/13/2040 6PM



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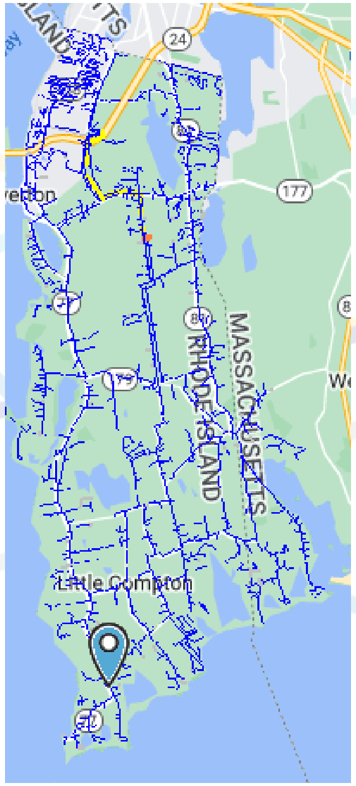
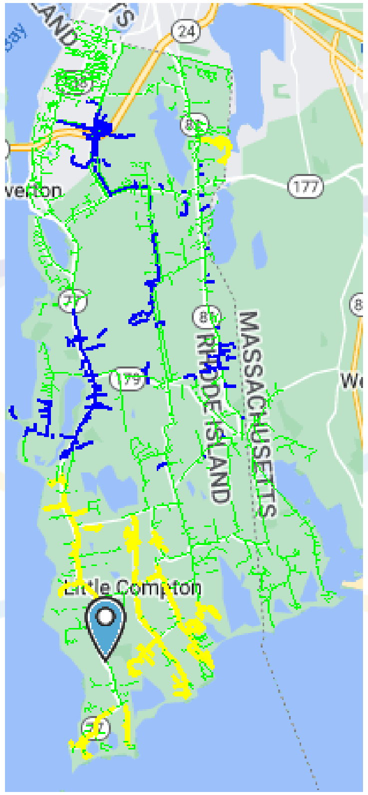
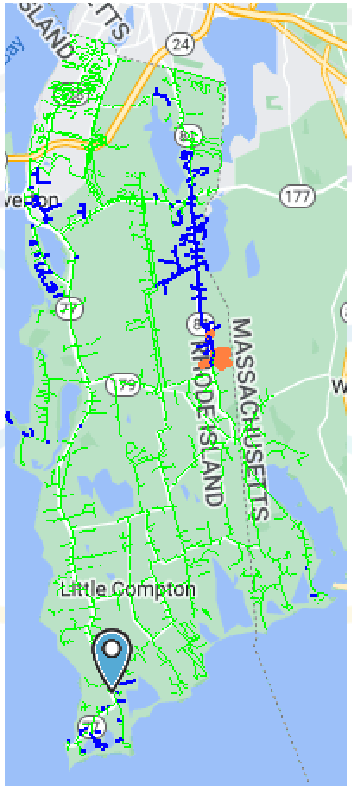


Voltage

2/13/2040 6PM



4/16/2040 11AM



GMP Model Demonstration – Key Takeaways

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- Need is now
  - System must be setup with proper sensing and data handling and processing now.
    - Each interconnection that occurs without consideration of DERMS (Distributed Energy Resource Management System) is a lost opportunity
    - Each energy storage resource that is interconnected without consideration of distribution system needs is a lost opportunity
    - Each electric vehicle or heating system that is installed without considerations of load shifting capabilities linked to the distribution system is a lost opportunity
    - Without grid modernization foundational investments, RIE has to pursue non-GMP type investments. Over time the savings that can be achieved from the GMP will be eroded
  - Study was conducted using a conservative dispersed DER allocation
    - Actual interconnections can cause localized acute issues in the immediate future
  - RIE customers are getting the ADMS Platform at no cost to enable automation of the system to maintain/improve safety and reliability; off-set T/D and System Capacity Cost; reduce energy usage, and reduce curtailment of renewable energy resources among other benefits
  - The greatest Grid Modernization benefits are achieved when linked to an AMF deployment. The combined smart devices provide comprehensive situational awareness and control required – e.g. FLISR, VVO, DER Monitor/Manage, Advanced Reclosers, Smart Capacitors and Regulators, Relay Upgrades
  - Deployment of these resources will take time and many other utilities across the country are addressing the same issues. Supply chain issues dictate that RIE deploy GMP on an accelerated basis.

Appendix

Acronyms

- ADMS = Advanced Distribution Management System
- AESC = Avoided Energy Supply Cost
- AMF = Advanced Meter Functionality
- AMI = Advanced Meter Infrastructure
- AMR = Automatic Meter Reading
- ASA = Amended Settlement Agreement
- ASHP = Air Source Heat Pump
- BAU = Business as Usual
- BCA = Benefit Cost Analysis
- C&I = Commercial and Industrial
- CEP = Customer Engagement Plan
- CGR = Connected Grid Router
- CO2 = Carbon Dioxide
- CP = Customer Portal
- CPP = Critical Peak Pricing
- D = Distribution
- DCFC = Direct Current Fast Charging
- DER = Distributed Energy Resource
- DERMS = Distributed Energy Resource Management System
- DG = Distributed Generation
- DLM = Dynamic Load Management
- DPAM = Distribution Planning & Asset Management
- DPL = Dayton Power and Light
- DR = Demand Response
- DRIPE = Demand Reduction Induced Price Effect
- DSCADA = Distributed Supervisory Control and Data Acquisition
- EC4 = Executive Climate Change Coordinating Council
- EE = Energy Efficiency
- EDI = Electronic Data Interchange
- EHP = Electric Heat Pump
- EIA = Energy Information Administration
- EPO = Energy Profiler Online
- ESB = Enterprise Service Bus
- EV = Electric Vehicle
- FAN = Field Area Network
- FLISR = Fault Location Isolation and Service Restoration
- GBC = Green Button Connect
- GBD = Green Button Download my data
- GHG = Greenhouse Gas
- GIS = Geographical Information Systems
- GMP = Grid Modernization Plan
- HAN = Home Area Network
- HCA = Hosting Capacity Analysis
- HES = Head End System
- HVAC = Heating, Ventilation, and Air Conditioning
- ICAP = Installed Capacity
- ICE = Interruption Cost Estimate
- IoT = Internet of Things
- IP = Internet Protocol
- ISA = Interconnection Service Agreement
- ISO NE = Independent System Operator New England
- IT = Information Technology
- KY = Kentucky
- LDV = Light Duty Vehicle
- LVA = Locational Value Analysis
- MA = Massachusetts
- MDM = Meter Data Management
- MV/LV = Medium Voltage/Low Voltage
- NEM = Net Energy Metering
- NMPC = Niagara Mohawk Power Corporation
- NPP = Non-Regulated Power Producer
- NY = New York
- NWA = Non-Wires Alternative
- OER = RI Office of Energy Resources
- OMS = Outage Management Systems
- PA = Pennsylvania
- PBR = Performance-Based Regulation
- PI Historian = Plant Information Historian
- PIM = Performance Incentive Mechanism
- PLC = Power-Line Communication
- PPL = Pennsylvania Power and Light
- PSE&G = Public Service Electric & Gas
- PSR = Platform Service Revenue
- PST = Power Sector Transformation
- PUC = Public Utilities Commission
- PV = Photovoltaic
- REC = Renewable Energy Credit
- REV = Reforming the Energy Vision
- RF = Radio Frequency
- RGGI = Regional Greenhouse Gas Initiative
- RI = Rhode Island
- RIE = Rhode Island Energy
- RMD = Residential Methane Detector
- RTP = Real Time Pricing
- RTU = Remote Terminal Unit
- SaaS = Software as a System
- SCT = Societal Cost Test
- SME = Subject Matter Expert
- ToC = Table of Contents
- TOU = Time Of Use
- TSA = Transition Service Agreement
- TVR = Time Varying Rate
- VDER = Value of Distributed Energy Resources
- VMT = Vehicle Miles Traveled
- VPP = Variable Peak Pricing
- VVO/CVR = Volt-Var Optimization/Conservation Voltage Reduction
- WACC = Weighted Average Cost of Capital

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Grid Modernization Plan Update

AMF/GMF Subcommittee
Power Sector Transformation Advisory Group
November 9, 2022

Business Use

Agenda

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• 10:00 – 10:10	Introductions, Objectives, Background
• 10:10 – 10:40	Study Results
• 10:40 – 11:10	GMP Functionality Discussion and Roadmap
• 11:10– 11:40	Preliminary BCA Discussion
• 11:40 – 12:00	AMF Linkage to GMP and Next Steps

Objectives

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- Discuss and solicit feedback on remaining aspects of the Grid Modernization Plan
  - ✓ Findings of GMP Analysis
  - ✓ Solutions Analysis
  - ✓ BCA Examples
- Next Steps

Ground Rules:

- Ask questions and provide feedback as we go
- Raise hand and state name when asking questions
- One conversation at a time
- Timekeeper to monitor discussion and align to agenda
- Topics and questions scheduled for future discussion will be saved in the Parking Lot

PST Advisory Collaboration

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PST Advisory AMF & GMP Subcommittee Meetings and Preliminary Agendas

Stakeholder Collaboration (i.e., Subcommittee meetings and discussions)

Obtain Feedback and Seek Alignment on Proposals and Approaches

Review Initial, Refined and Final Proposals

Jun 21, 2022
- **RI Division and OER Meeting**
- Introductions
- Proposed timeline
- Preliminary agenda for PST meetings
- AMF Introduction and overview of key areas
- GMP Introduction and coordination

July 14, 2022
- **PST Advisory Meeting**
- Introductions
- PPL Background and Experience
- Full Scale Enabling Platform
- Detailed Deployment Plan
- Functionality Timing
- ASA coverage
- AMF cost review
- GMP study scope and approach
- GMP forecast analysis

Aug 2, 2022
- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Customer Engagement Plan
- AMF Opt-out
- AMF Customer value streams
- AMF Auto-notification
- AMF Benefits

Aug 16, 2022
- **PST Advisory Meeting**
- Prior meeting will drive agenda
- AMF Data access, privacy, governance
- AMF Cyber Security
- AMF Cost and Benefit Recap
- Cost Recovery and Revenue Requirements
- GMP scenario analysis
- GMP solution development
- GMP ISR Coordination plans

Sept 1, 2022
- **PUC Technical Session**

November 2022
- **File AMF**
- **AMF includes Business Case, Testimonies and BCA**
- **Coordinates with GMP execution plan and BCA**

Oct 7, 2022
- Grid Modernization Plan Model Demonstration

Oct 18, 2022
- **PUC Technical Session**

Nov 9, 2022
- PST Advisory Meeting
- Prior meeting will drive agenda
- GMP Alternative recommendation
- GMP BCA review

w/o Dec, 2022
- Grid Modernization Plan Final BCA Review

December 2022
- **File GMP**
- GMP Includes Business Case, Testimonies and BCA
- Coordinate with ISR and AMF details

November 2022
AMF Targeted Filing Date

December 2022
GMP Targeted Filing Date

🟦	Initial alignment meeting with RI Division and OER
🟦	PST Advisory Sub-Committee Meeting AMF
🟩	PST Advisory Sub-Committee Meeting GMP
🟨	PUC Technical Session

AMF – Advanced Metering Functionality GMP – Grid Modernization Plan BCA – Benefit-Cost Analysis

GMP Strategy, Goals and Approach

Objectives

1. Invest in the grid so that it meets 21st century demands and the State's clean energy mandates
2. Improve customer service:
    - Improve reliability and safety
    - Maintain / optimize voltage
    - Provide reliable DER interconnections
    - Balance DG and load for stability

Strategy - Apply Grid Modernization

- Automatically restore customers where possible
- Centralize voltage and power quality management with automated capacitor and regulators, and monitoring/managing DERs
- Gain visibility and control to operate reliably with forecasted DER penetration
- Dynamically adapt protection settings based on system configuration
- Improve capability to detect downed conductors
- Predict failures before they occur, respond faster to incidents and use data to improve operations

Goals

- Create situational awareness, operate voltage within tolerance and optimize control
- Realize VVO/CVR functionality
- Design automatic sectionalization considering reliability, DER penetration, contingency capability, resiliency, and load-DG balance
- Achieve PPL EU reliability level with IEEE definition
- Implement DER Monitoring/Management
- Provide reliable, affordable power that meets objectives

Approach

- Use RIE Distribution Study Effort (2030/40/50) to develop ultimate plan, drive priorities and sequencing
- Coordinate with ADMS deployment efforts to align software functionality requirements
- Define transmission, sub-transmission, and substation technology needs to achieve overall strategy
- Review system upgrades alternatives including Transmission and storage etc. to accommodate new load
- Introduce DER Monitor/ Manage capability
- Request approval for ASA compliance
- Include GMP Foundational Investments in ISR

Grid Modernization DER Forecast – Impact to Peak

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GMP DER Forecast/Impact to Peak

	2030		2040		2050	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps (Ea.) Forecast	54,000	54,000	325,000	325,000	400,000	400,000
Heat Pumps (MW) @ Peak	0	200	5	1310	5	2825
Solar PV Nameplate (MW) Forecast	1,500	1,500	3,400	3,400	5,000	5,000
Solar PV Nameplate (MW) @ Peak	0	0	0	0	0	0
Electric Vehicles (Ea.) Forecast	87,300	87,300	675,000	675,000	840,000	840,000
Electric Vehicles (MW) @ Peak	70	80	805	910	1010	238
RIE Peak Demand (MW)	**1,940**	**1,415**	**2,519**	**3,280**	**2,785**	**3,855**

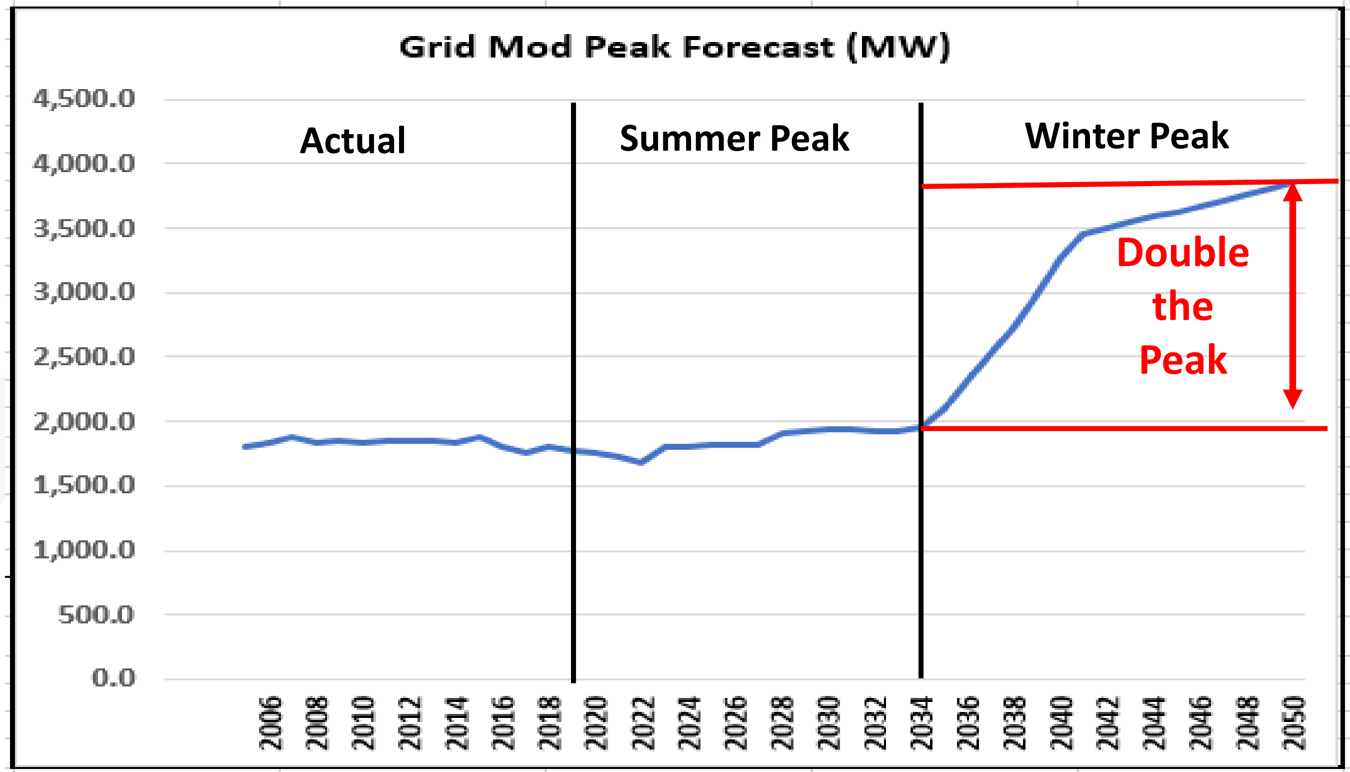
More Distributed Generation than Load

Winter Peak

Peak Demand Doubles

Let's Talk About the Peak

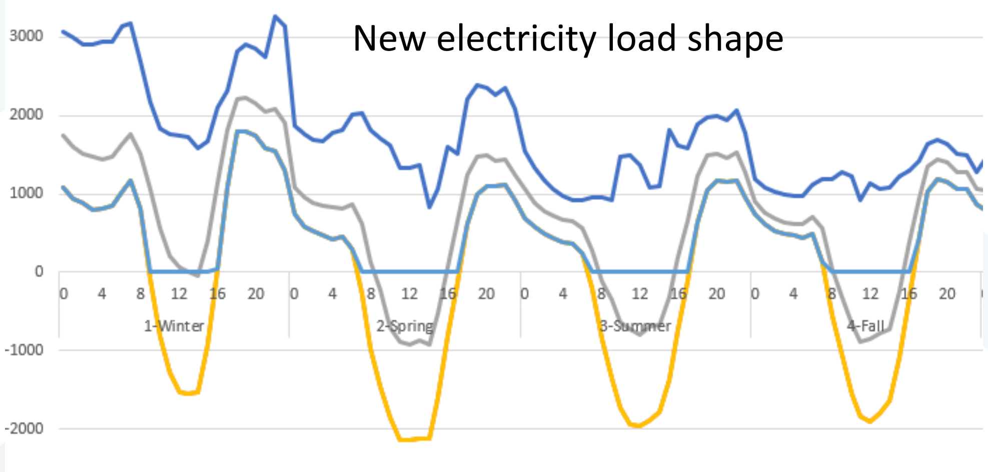
- Rhode Island Energy's current peak load is ~1,800-1,900 MW
- By 2050 it is estimated to go to 3,900 with the additional EVs and EHPs added to the system
- Significant penetration of DERs but they have zero impact on Winter Peak and very little impact on the Summer Peak due to SP moving later in the day



Let’s Talk About the Load Shape

- The doubling of the peak creates need for more infrastructure to serve the peak
- Significant penetration of DERs changes the load shape, providing generation when it’s not needed and not providing it when it is needed
- The drastically changing load shape creates additional issues due to a need to balance load and generation at every instant of every day

Traditional Electric utility load shape


New electricity load shape

Study Results

GMP Forecast to Meet Climate Mandate

GMP tests Electric System limits to meet Act on Climate Mandate with the following contributing factors:

1. Heating Sector/Commercial and Residential
   - Oil Heat conversions to electric
   - Natural Gas Heat conversions to electric
2. Transportation Sector/Commercial and Residential
   - Gas powered conversions to electric
3. Electric Sector
   - Fossil Fuel (Natural Gas majority in RI) generation conversion to renewable
   - Additional renewable generation to serve increase demand from other sectors

GMP filing proposes <u>foundational investments</u> needed for any level of forecasted adoption: no regrets decision

- Actual adoption in all sectors is uncertain and will vary
- Rates and levels of adoption does not avoid the need for the foundational investments
- Specific adoption may prompt future investments which are not part of the GMP filing.

Heating Sector

- A consideration in the GMP and the Action on Climate Studies
- Natural Gas Heat conversions to electric is the only overlap
- Forecast alignment for Natural Gas Heat conversion to electric is not required for the GMP study

Grid Modernization Study Scope and Status

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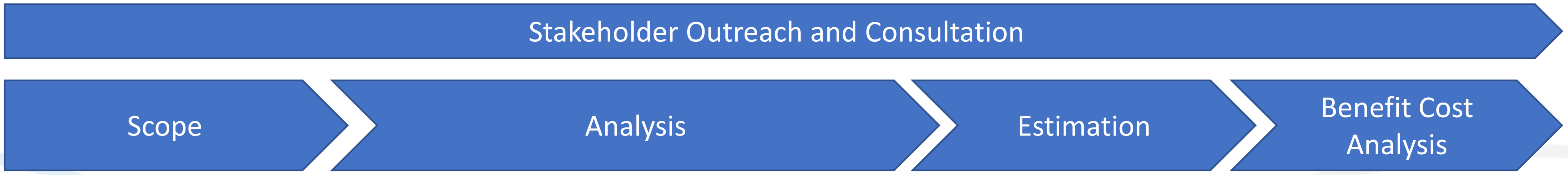


Stakeholder Outreach and Consultation

Scope

Analysis

Estimation

Benefit Cost Analysis

State-wide 8760 analysis

- ✓ 400 feeders
- ✓ Includes area study recommendations
- ✓ Sub-transmission modeling and testing
- • System-wide transmission analysis

Years: 2030, 2040, 2050 – Aligned with Act on Climate

Applied DER forecast to Area Studies:

- ✓ Applied ramped DER forecast to meet Clean Energy Mandate

Issue Identification:

- ✓ Determine load, voltage and protection issues
- ✓ Determine areas with degrading reliability
- ✓ Consider resiliency needs

Solutions:

- ✓ Non-Grid Modernization Solutions – Build for Extremes
  - ✓ Expand Distribution, Sub transmission and Transmission
- ✓ Grid Modernization Solutions – Manage away Extremes
  - ✓ Reduced Expansion of Distribution, Sub transmission and Transmission
  - ✓ System wide Automation & deployment of Sensing, Monitoring, Data Handling and Processing
  - ✓ DER Monitor Manage Energy Shift (TOU)
  - ✓ Battery Energy Storage Systems

Estimation:

- ✓ Equipment Costs
- ✓ Installation Costs
- ■ Final Cost Revisions

Road Map:

- ■ Device Deployment Plan
- ✓ Functionality Availability

Leverage PPL experience

- ✓ Actual Costs
- ✓ Installation Assumptions
- ✓ Standards

BCA:

- • Comply with Docket 4600
- • Update with PPL experience, Study and Reliability findings

Transition Component:

- • ADMS 'Basic' came with the acquisition

Business Plan

- • Write business plan

✓ Complete
• In Progress

RIE Operational Characteristics Now

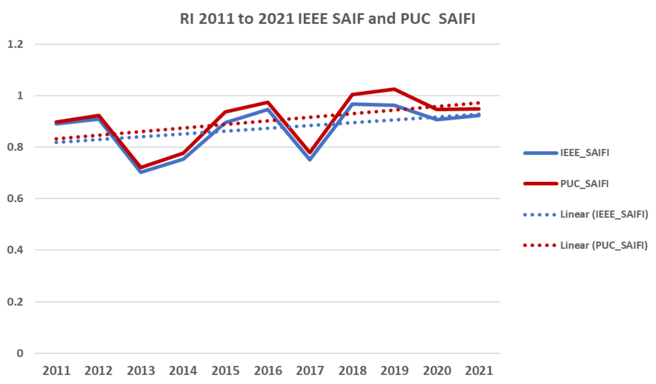
- Operational Characteristics:
  - Growing DER adoption and interconnection queue
  - Increased variability of load, voltage, and power flow which increases system complexity
  - Greater operational uncertainty
  - Greater dependency on local generation to balance with load
  - Lacking real time situational awareness

- Consequence:
  - Increasing reliability and safety risk (see trend)
  - DER curtailment and interconnection delays
  - Challenges to recover from major events
  - Recent example at Nasonville

Solar DER nominal voltage output in RIE Newport Region - May 2022

*Voltage repeatedly exceeds 1.05 per unit operating target

*Required to maintain ±5% of nominal voltage ie 0.95 to 1.05 per unit voltage.



SAIFI trending worse (up) in recent years

Business Use

Grid Modernization Area Study Model Inputs

- Base Model – as used with typical planning studies
  - **Area study recommendations**
  - Existing distributed generation confirmed
- Forecasted load, generation, electric vehicles, heating (heat pumps) added
  - Load forecast with energy efficiency incorporated into load profiles
  - Generation added to the model explicitly
    - General distribution PVs added as 100kW sites
    - Specific PV and Wind sites added to sub-transmission
    - Generation load cycles are based on PVWatts and actual data
  - Electric vehicles and heat pumps added as customer load types to existing load sites
    - Electric vehicle load cycle based on EVI-Pro-Lite
    - Heating pump load based on industry research and 2015 weather year

Load Flow and Protection Analysis

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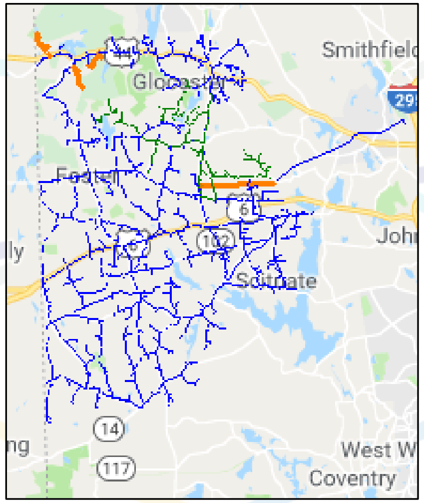
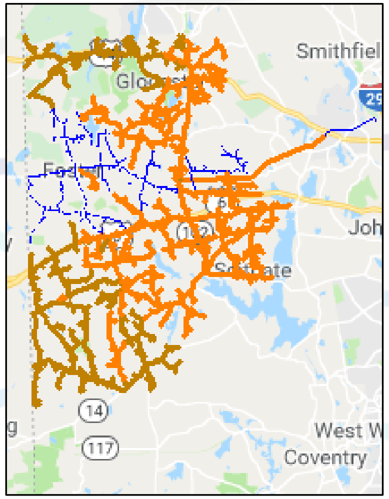
- Python script tools developed to distribute PV, EV, and EHP
    - Scattered approach, no propensity modeling
- Time Range Analysis is data intensive and time consuming
    - Time range analysis used to find key dates/times
    - Single time analysis done on key date/time

- Example: Voltage Violation – 5/25 at 12:00 pm
    - Peak load – minimal voltage issues
    - Light load - high voltage with DG – shown in **ORANGE**, **BROWN**



Summer Peak Load



Summer Light Load

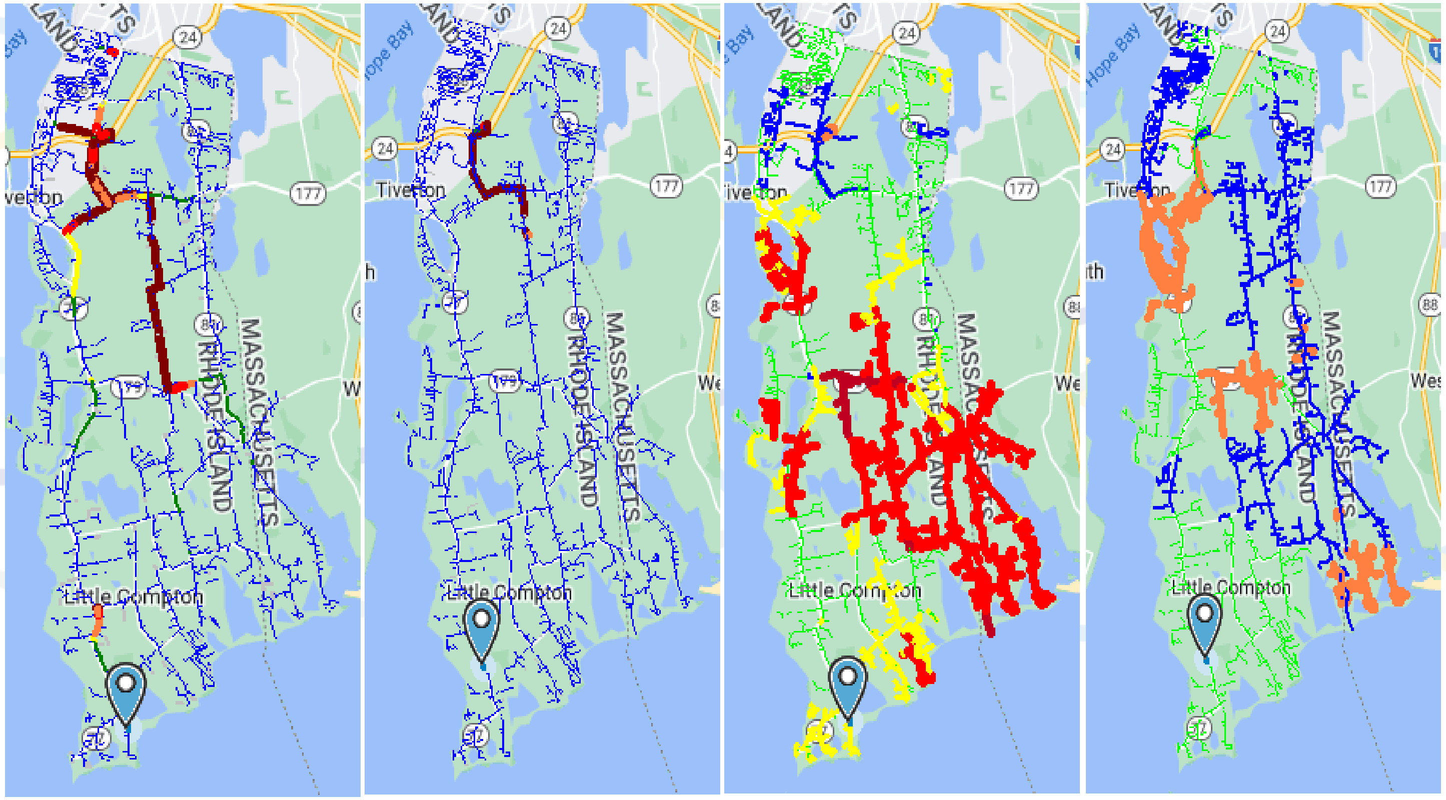
Grid Modernization Tiverton Preliminary Area Results 2040

Loading

2/13/2040 6PM　4/16/2040 11AM

Voltage

2/13/2040 6PM　4/16/2040 11AM



Business Use

Cool colors are shaded and have no issues

🟦 🟩 🟩

Warm colors are issues

🟧 🟥 🟨 🟫

Grid Modernization Tiverton Preliminary Area Solutions

Non-Grid Mod Alternative: Build for extremes by expanding Distribution, Sub-transmission and Transmission

- 3 new feeders added to existing Tiverton Substation
- New area Substation with 2 new feeders added

Grid Mod Alternative: Manage away extremes with system wide automation and deployment of sensing, monitoring, data handling and processing and reducing expansion of distribution, sub-transmission and transmission. Includes, DER Monitor Manage Energy Shift and Battery Energy Storage Systems

- 2 new feeders to existing Tiverton Substation
- 4 BESS Sites - Generation shifts
- Load shifts

- Main Point of the Study is to compare Grid Mod to Non-Grid Mod Alternatives to ensure most prudent option is being recommended

- Results indicate that a Grid Mod Alternative results in 30-50% of deferred capital investments (difference between grid mod and non grid mod alternatives)

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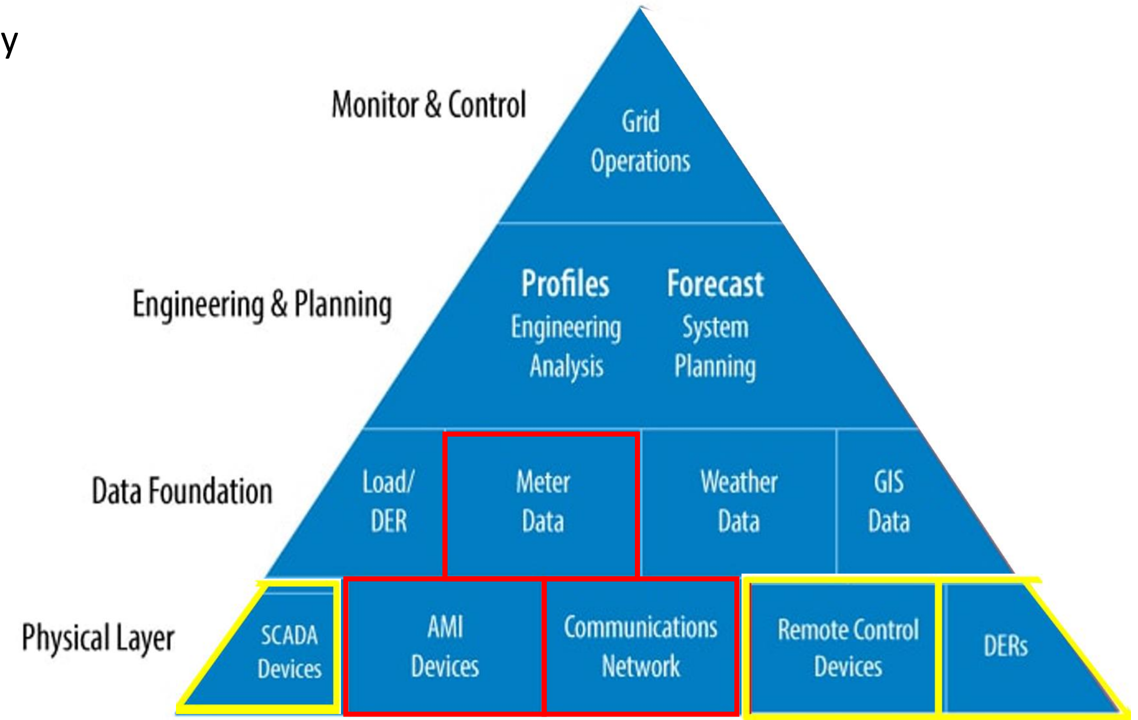
GMP Functionality Discussion and Roadmap

Position for Future Success

- Infrastructure transformation is needed to enable energy policy mandates where traditional one-way power flow is intermittent, multi-directionally, dynamic and unpredictable
- Visibility and enhanced distribution control is necessary for reliable and safe operations
- By applying the grid modernization pyramid, situational awareness and system control can be achieved to successfully operate in the new world
- Approach - recognize evolving needs, identify capability gaps and define ideal characteristics
- Apply technology solutions and leverage data to meet requirements
- Optimize value through intregration



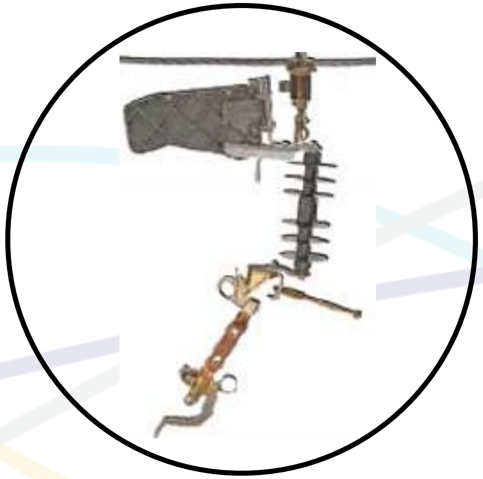
Grid Modernization Pyramid

🟥 AMF is foundational and an enabling platform
🟨 GMP investments are an operational necessity

The Present – Many Mechanical Devices

Protective:
Oil-Circuit Recloser

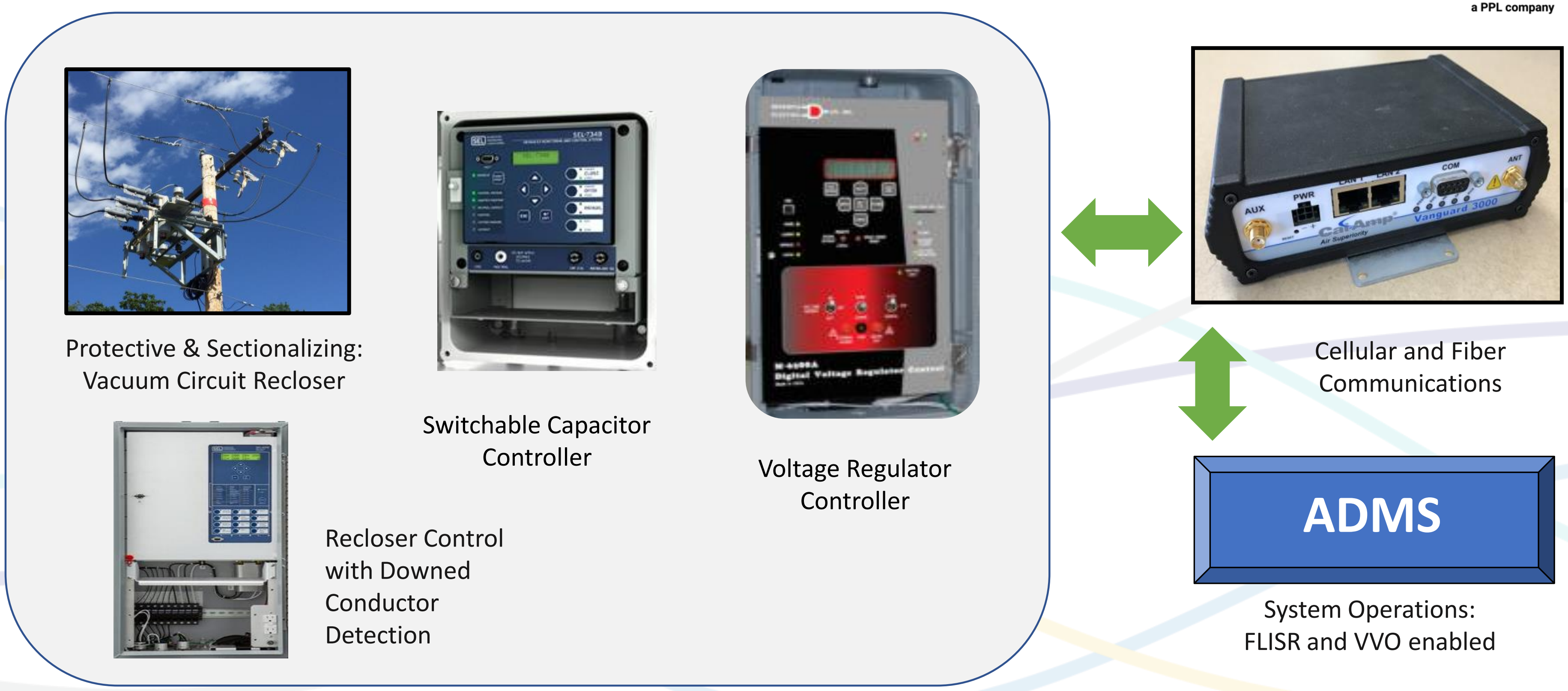
Sectionalizing:
Air-Break Switch



Sectionalizing:
Load-Break Switch

Sectionalizing:
Fused Cutout

The Proposed – Grid Modernization Components



Protective & Sectionalizing:
Vacuum Circuit Recloser

Switchable Capacitor
Controller

Voltage Regulator
Controller

Recloser Control
with Downed
Conductor
Detection

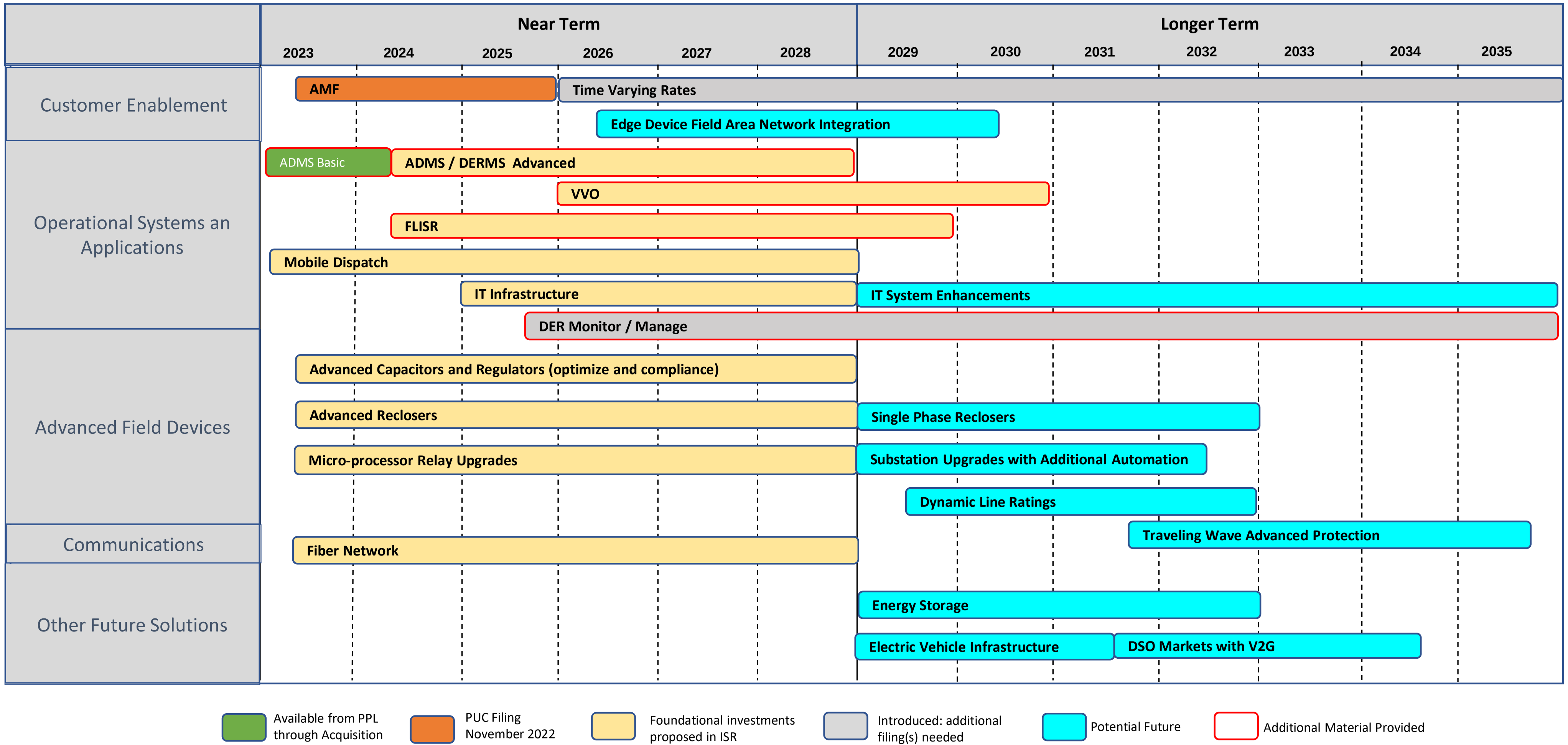
Cellular and Fiber
Communications

ADMS

System Operations:
FLISR and VVO enabled

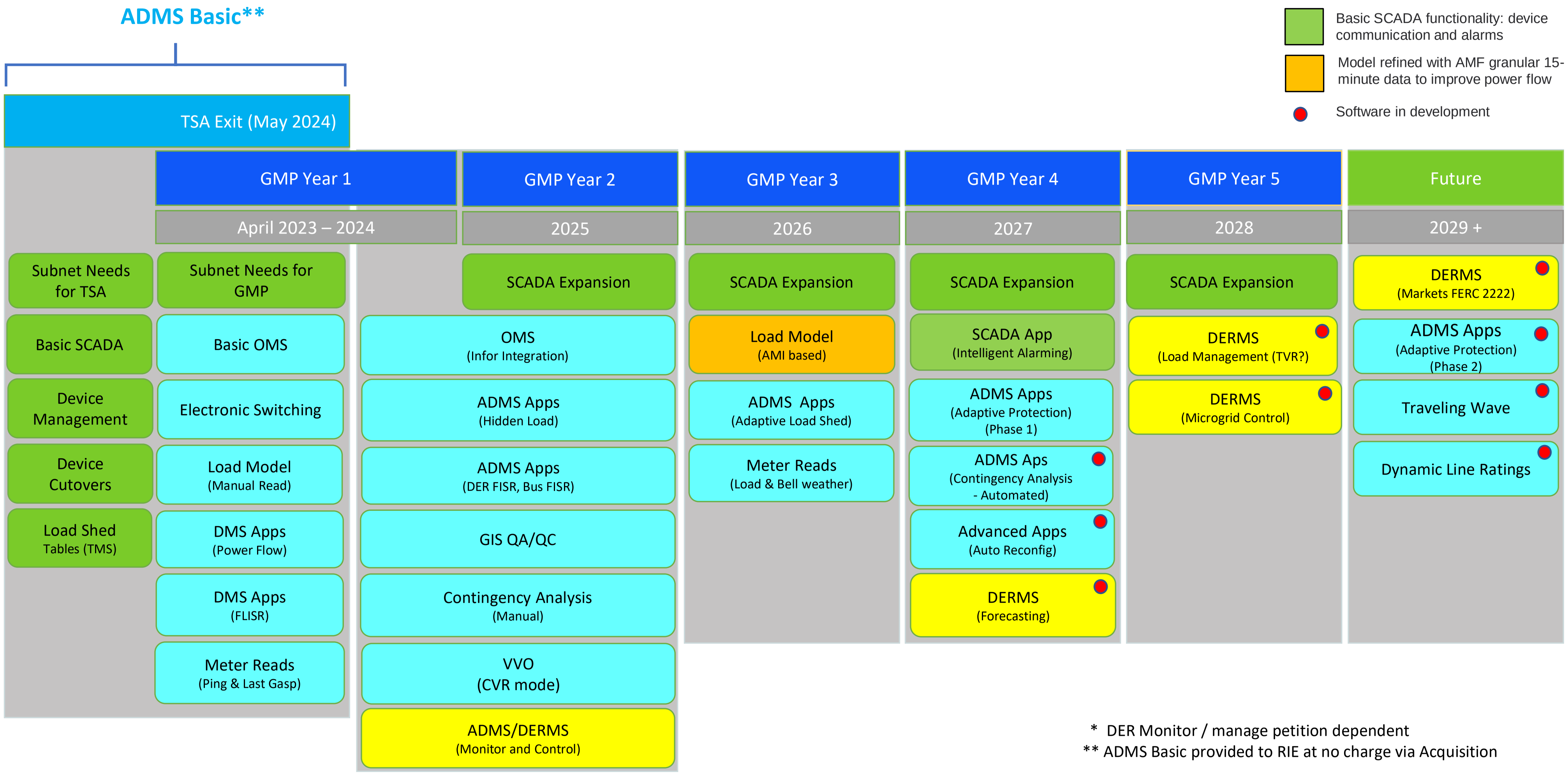
- Provides operational flexibility, remote settings and operation, ADMS telemetry, forward/reverse fault detection
- Collectively provides comprehensive situational awareness and increased system control
- The greatest benefits when linked to an AMF

Preliminary GMP Roadmap



Operational System Functionality

- 🟨 DERMS related – associated with DER Monitor / Manage*
- 🟦 DMS application ie GIS, power flow, OMS, FLISR, fault location
- 🟩 Basic SCADA functionality: device communication and alarms
- 🟧 Model refined with AMF granular 15-minute data to improve power flow
- ● Software in development



ADMS Basic**

TSA Exit (May 2024)

- Subnet Needs for TSA
- Basic SCADA
- Device Management
- Device Cutovers
- Load Shed Tables (TMS)

GMP Year 1 – April 2023 – 2024
- Subnet Needs for GMP
- Basic OMS
- Electronic Switching
- Load Model (Manual Read)
- DMS Apps (Power Flow)
- DMS Apps (FLISR)
- Meter Reads (Ping & Last Gasp)

GMP Year 2 – 2025
- SCADA Expansion
- OMS (Infor Integration)
- ADMS Apps (Hidden Load)
- ADMS Apps (DER FISR, Bus FISR)
- GIS QA/QC
- Contingency Analysis (Manual)
- VVO (CVR mode)
- ADMS/DERMS (Monitor and Control)

GMP Year 3 – 2026
- SCADA Expansion
- Load Model (AMI based)
- ADMS Apps (Adaptive Load Shed)
- Meter Reads (Load & Bell weather)

GMP Year 4 – 2027
- SCADA Expansion
- SCADA App (Intelligent Alarming)
- ADMS Apps (Adaptive Protection) (Phase 1)
- ADMS Aps (Contingency Analysis - Automated) ●
- Advanced Apps (Auto Reconfig) ●
- DERMS (Forecasting) ●

GMP Year 5 – 2028
- SCADA Expansion
- DERMS (Load Management (TVR?) ●
- DERMS (Microgrid Control) ●

Future – 2029 +
- DERMS (Markets FERC 2222) ●
- ADMS Apps (Adaptive Protection) (Phase 2) ●
- Traveling Wave ●
- Dynamic Line Ratings ●

* DER Monitor / manage petition dependent
** ADMS Basic provided to RIE at no charge via Acquisition

Business Use

Volt VAR Optimization (VVO)

- Requires
  - ADMS: VVO (CVR Mode) enabled
  - Automated Capacitors and Regulators
  - Voltage inputs from AMF and / or sensors

- Assumption
  - Provides 2.5% energy savings: AMF = .5%, GMP = 2%
  - Reduced by 10% to reflect the feeders that have VVO
  - Research shows VVO/CVR savings ranging from 1% to 4.7%
  - RIE’s experience on two feeders provided 3.5% savings
  - AMF avoids line sensors and provides granular visibility
  - Benefits ramp up from 2026 - 2031

ADMS

System Operations:
VVO enabled

Communications

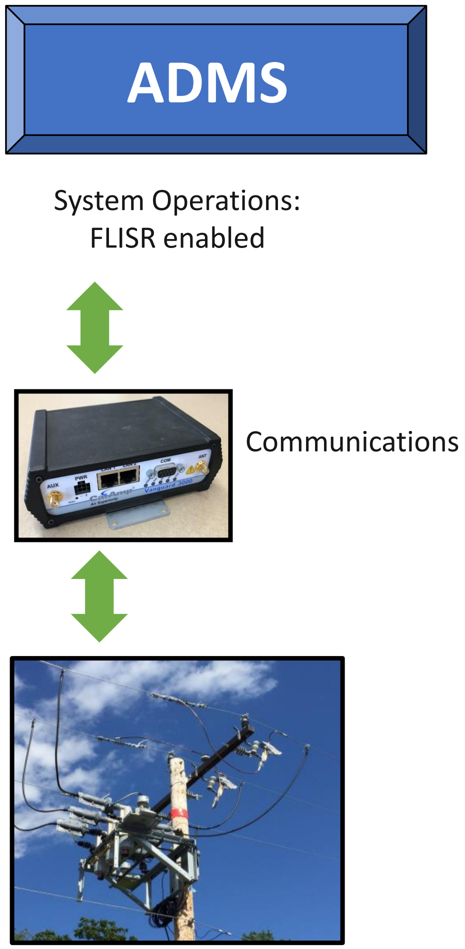
Switchable Capacitor
Controller

Business Use

Fault Location Isolation and Service Restoration (FLISR)

- Requires
  - ADMS: FLISR enabled
  - Automated Reclosers
  - Enhanced with Last Gasp and Power Up AMF Data

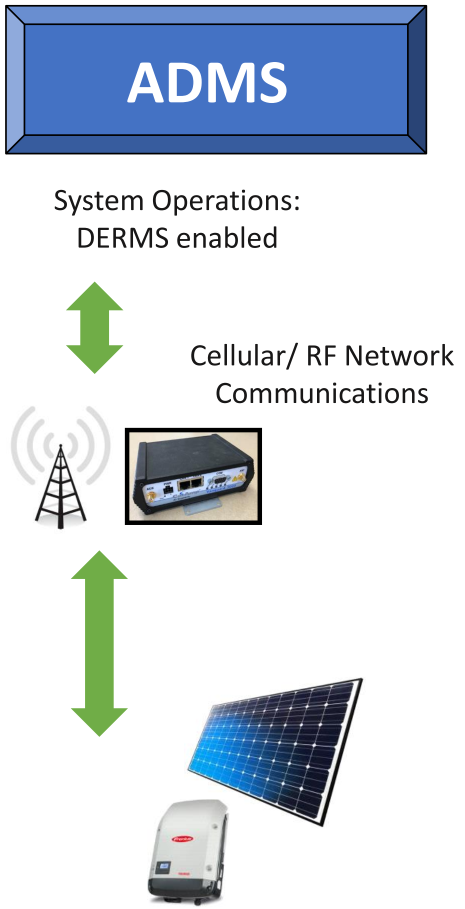
- Assumption
  - Foundational investments include Automated Reclosers
  - Utilizes ADMS Basic provided at no cost from the Acquisition
  - FLISR estimated to provide up to 30% SAIFI improvement
  - Benefits start in 2024 and increase with additional field automation
  - Expected to improve customer satisfaction



DER Monitor / Manage

- Requires
  - ADMS: DERMS enabled
  - IEEE 1547-2018 certified smart inverters
  - DER Monitor / Manage field equipment
  - Communications: RF mesh or cellular

- Assumption
  - Enabled by IEEE 1547-2018 standard
  - Provides second port on smart inverters for distribution utilities
  - Foundational investments includes DER Monitor / Manage
  - Utilizes ADMS DERMS enabled software
  - Provides ability to monitor DERs, change settings, and adjust output (rather than curtailing) for system needs
  - DER Monitor / Manage requires petition approval



ADMS

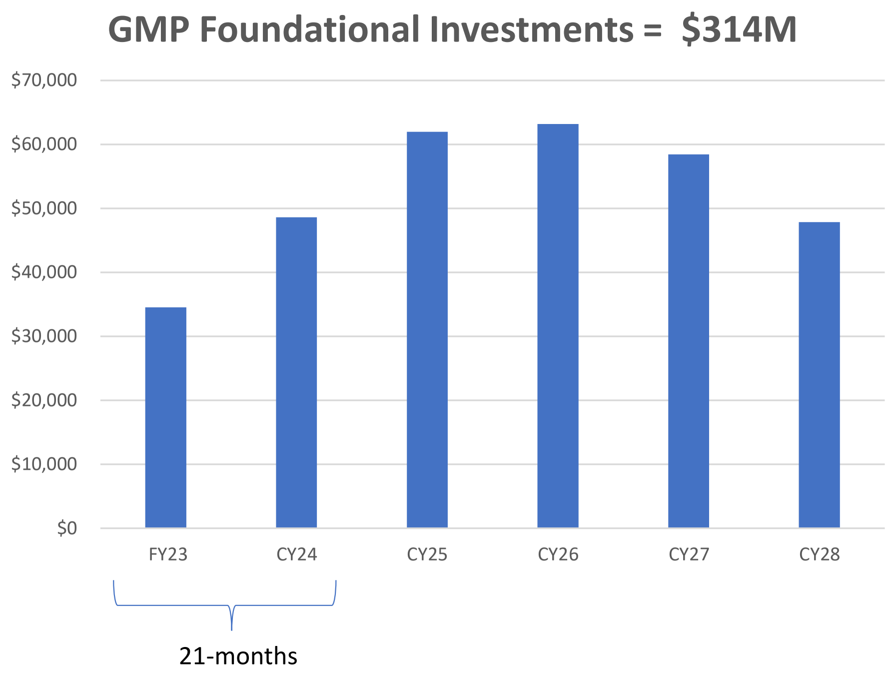
System Operations:
DERMS enabled

Cellular/ RF Network
Communications

GMP Foundational Investments

- Programs
  - ADMS/DERMS Advanced
  - Advanced Capacitors & Regulators
  - Advanced Reclosers
  - DER Monitor/Manage
  - Electro-mechanical Relay Replacements
  - Fiber Network
  - IT Infrastructure
  - Mobile Dispatch

- No Regrets Investment that is needed for any adoption scenario



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Preliminary BCA Results Discussion

Preliminary BCA Solutions to Address GMP Analysis Findings

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Introduction

- Still working on the Benefit/Cost analysis for Grid Modernization
- Have some benefits calculated
- Numbers are VERY preliminary

BCA Basics

Benefits Discussed Today

- Avoided Transmission & Distribution Costs
- VVO/CVR
- Time-Varying Rates
- Reliability – Reduced Frequency of Outages

Benefit Cost Analysis (BCA) Basics

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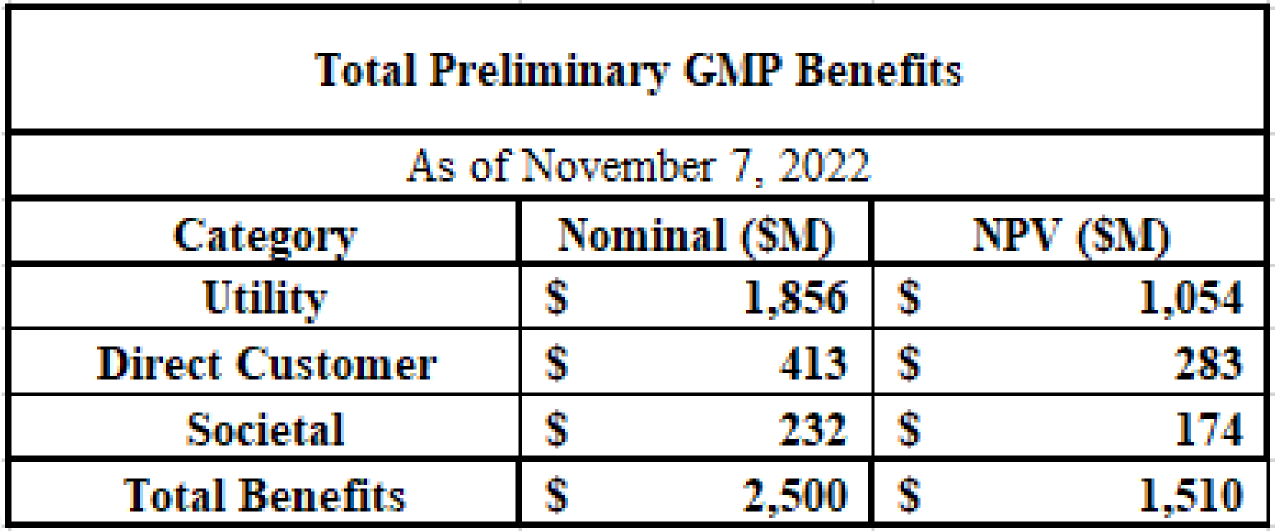
RI GMP BCA Tool is based on the AMF BCA Tool, so GMP BCA assumptions are kept as close as possible to the AMF BCA Tool

RI GMP BCA Model Assumptions	Values	Notes
NPV Analysis Period	20 year	Consistent with AMF BCA; analysis period specified by PUC
Discount Rate (After-Tax WACC)	6.97%	Consistent with AMF and NWA BCAs
Labor Escalation Rate	3.00%	Consistent with AMF BCA; based on July 1, 2019 base rate cost of service for management employees
Non-Labor Escalation Rate	2.26%	Consistent with AMF BCA; Moody's forecasts of BEA and BLS statistics
Benefit Value Metrics	AESC, EPA, ISO-NE, DOE ICE Tool	Consistent with AMF BCA; generally consistent with the Energy Efficiency Program BCA

Preliminary Benefits Summary

Results thus far: Nominal and $2022 Millions



Total Preliminary GMP Benefits				
As of November 7, 2022				
Category	Nominal ($M)		NPV ($M)	
Utility	$	1,856	$	1,054
Direct Customer	$	413	$	283
Societal	$	232	$	174
Total Benefits	$	2,500	$	1,510

Preliminary Benefits Summary by Program

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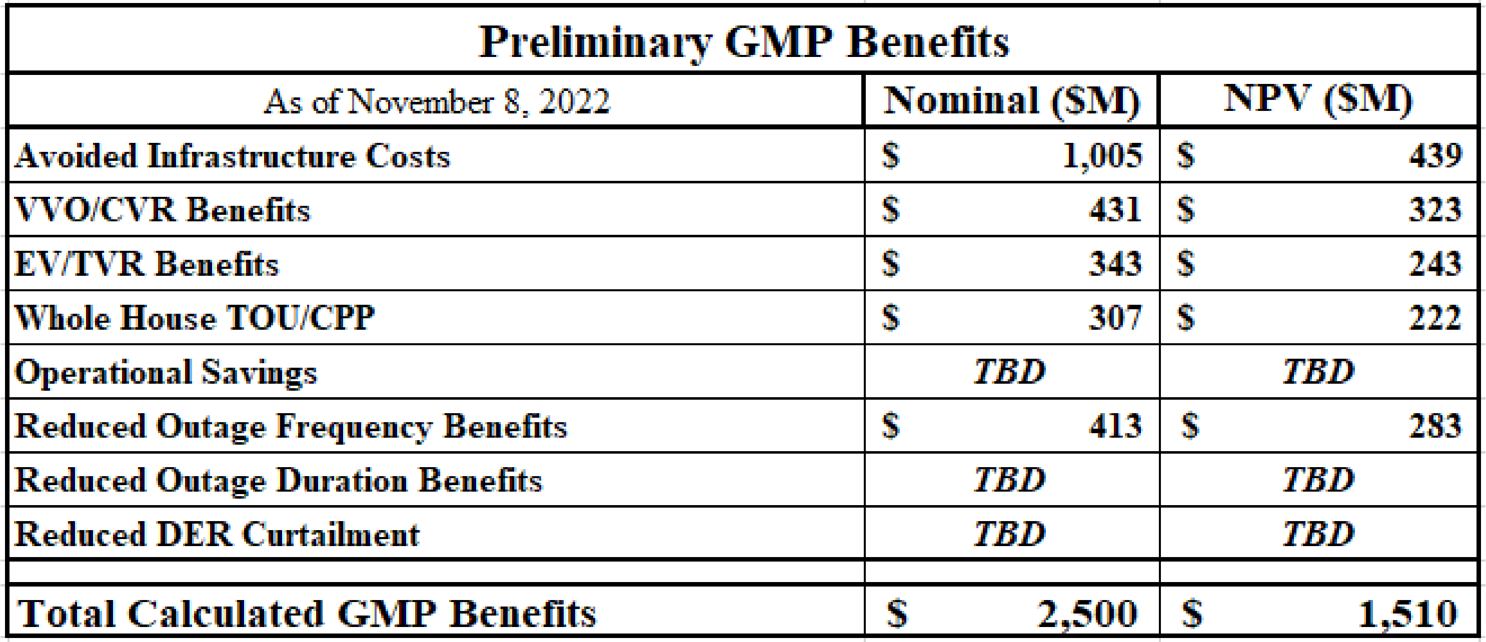
Results thus far: Nominal and $2022 Millions



Preliminary GMP Benefits		
As of November 8, 2022	Nominal ($M)	NPV ($M)
Avoided Infrastructure Costs	$ 1,005	$ 439
VVO/CVR Benefits	$ 431	$ 323
EV/TVR Benefits	$ 343	$ 243
Whole House TOU/CPP	$ 307	$ 222
Operational Savings	*TBD*	*TBD*
Reduced Outage Frequency Benefits	$ 413	$ 283
Reduced Outage Duration Benefits	*TBD*	*TBD*
Reduced DER Curtailment	*TBD*	*TBD*
Total Calculated GMP Benefits	**$ 2,500**	**$ 1,510**

Benefits – Avoided Infrastructure Costs

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Assumptions

- GMP forecast developed to meet Act on Climate clean energy mandates
- Each of 11 Areas modeled for 8760 hours of the year to identify "new" problem hours
- Base Case: Solved thermal and voltage overloads with traditional wires and support equipment
- GMP Case: Solved thermal and voltage overloads using Grid Modernization equipment and functionalities
- Avoided savings represent the difference between the two cases

Preliminary

Preliminary Avoided GMP Infrastructure Costs				
As of November 8, 2022	Nominal ($M)		NPV ($M)	
Tiverton Area - Avoided Infrastructure Costs	$	53	$	23
Providence Area - Avoided Infrastructure Costs	$	116	$	51
SCW Area - Avoided Infrastructure Costs	$	31	$	14
NCRI Area - Avoided Infrastructure Costs	$	141	$	61
SCE Area - Avoided Infrastructure Costs	$	75	$	33
BVN Area - Avoided Infrastructure Costs	$	62	$	27
BVS Area - Avoided Infrastructure Costs	$	98	$	43
CRIE Area - Avoided Infrastructure Costs	$	88	$	38
CRIW - Avoided Infrastructure Costs	$	185	$	81
EB - Avoided Infrastructure Costs	$	23	$	10
Newport Area - Avoided Infrastructure Costs	$	135	$	59
Total Avoided Infrastructure Costs	**$**	**1,005**	**$**	**439**

Benefits – Volt/Var Optimization/Conservation Voltage Reduction

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Assumptions

- Grid Modernization will allow Rhode Island Energy to save 2% of energy using VVO/CVR
- GMP forecasts of peak and energy include DERs, Electric Vehicles and Electric Heat Pumps
- 10% of feeders already have VVO/CVR
- AESC 2021 values for avoided costs and AESC discount rate
- Capacity lag: 3 years

Preliminary

Preliminary GMP VVO/CVR Benefit		
As of November 8, 2022	**Nominal ($M)**	**NPV ($M)**
GMP - Total Non-Embedded CO2 Benefit: VVO/CVR	$ 222	$ 167
Energy Savings: VVO/CVR	$ 138	$ 103
Monetized CO2 Benefit: VVO/CVR	$ 32	$ 24
Trans Capacity Benefit: VVO/CVR	$ 17	$ 12
GMP - System Capacity Benefit: VVO/CVR	$ 12	$ 9
GMP - Total Public Health Benefit: VVO/CVR	$ 9	$ 6
Dist Capacity Benefit: VVO/CVR	$ 1	$ 1
GMP - Total Non-Embedded NOX Benefit: VVO/CVR	$ 1	$ 0
Total VVO/CVR Benefits	**$ 431**	**$ 323**

Benefits – Electric Vehicle TVR

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Assumptions

- Start with an Opt-In TVR program and transition to an Opt-Out program as more Electric Vehicles come on system
- Program Start Year: 2026
- EVs kWh use:
  - 3,500 kWh in 2022
  - 4,300 kWh in 2041
- EVs' Contribution to Peak:
  - .6 kW in 2022
  - 1.4 kW in 2041
- Peak Savings increase from 29% in 2022 to 60% in 2041
- AESC 2021 values for avoided costs and AESC discount rate

Preliminary

Preliminary EV/TVR Benefit - Mix of Opt-In and Opt-Out		
As of November 8, 2022	Nominal ($M)	NPV ($M)
GMP Total Trans Capacity Benefit: EV TVR	$ 187	$ 132
GMP - Total System Capacity Benefit: EV TVR	$ 138	$ 97
GMP Total Dist Capacity Benefit: EV TVR	$ 12	$ 9
GMP - Total Energy Shift Benefits: EV TVR	$ 6	$ 5
Total EV/TVR Benefits	**$ 343**	**$ 243**

Benefits – Whole House Time-of-Use/Critical Peak Pricing

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Preliminary

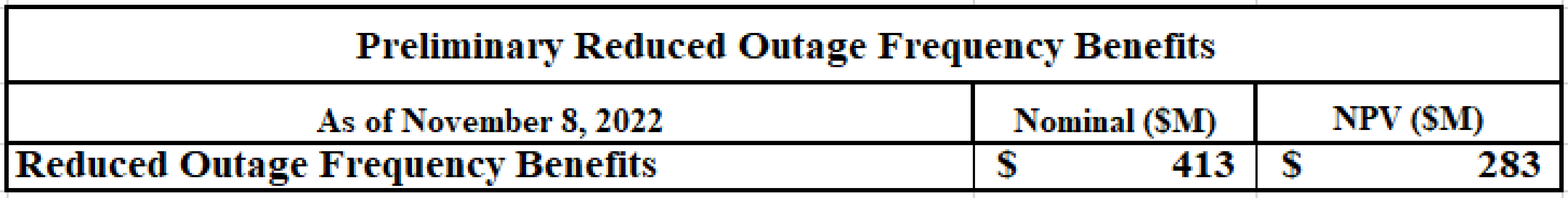
Assumptions

- Start with an Opt-In TVR program and transition to an Opt-Out program as more Electric Heat Pump
- Program Start Year: 2026
- Peak Savings: TOU
  - 3.7% Opt-In
- Peak Savings: TOU
  - 2.1% Opt-Out
- Peak Savings: CPP – 20%
- AESC 2021 values for avoided costs and AESC discount rate

Preliminary Whole House TOU/CPP - Mix of Opt-In and Opt-Out		
As of November 8, 2022	Nominal ($M)	NPV ($M)
GMP Total Trans Capacity Benefit: Whole House CPP	$ 174	$ 126
GMP - Total System Capacity Benefit: Whole House CPP	$ 116	$ 84
GMP Total Dist Capacity Benefit: Whole House CPP	$ 3	$ 3
GMP Total Capacity DRIPE Benefit: Whole House CPP	$ 4	$ 3
GMP - Total System Capacity Savings: Whole House Time-of-Use	$ 9	$ 7
GMP Total Trans Capacity Benefit: Whole House TOU	$ 1	$ 1
GMP Total Dist Capacity Benefit: Whole House TOU	$ 0	$ 0
Total Whole House TOU/CPP	$ 307	$ 222

Benefits - Reliability

Preliminary



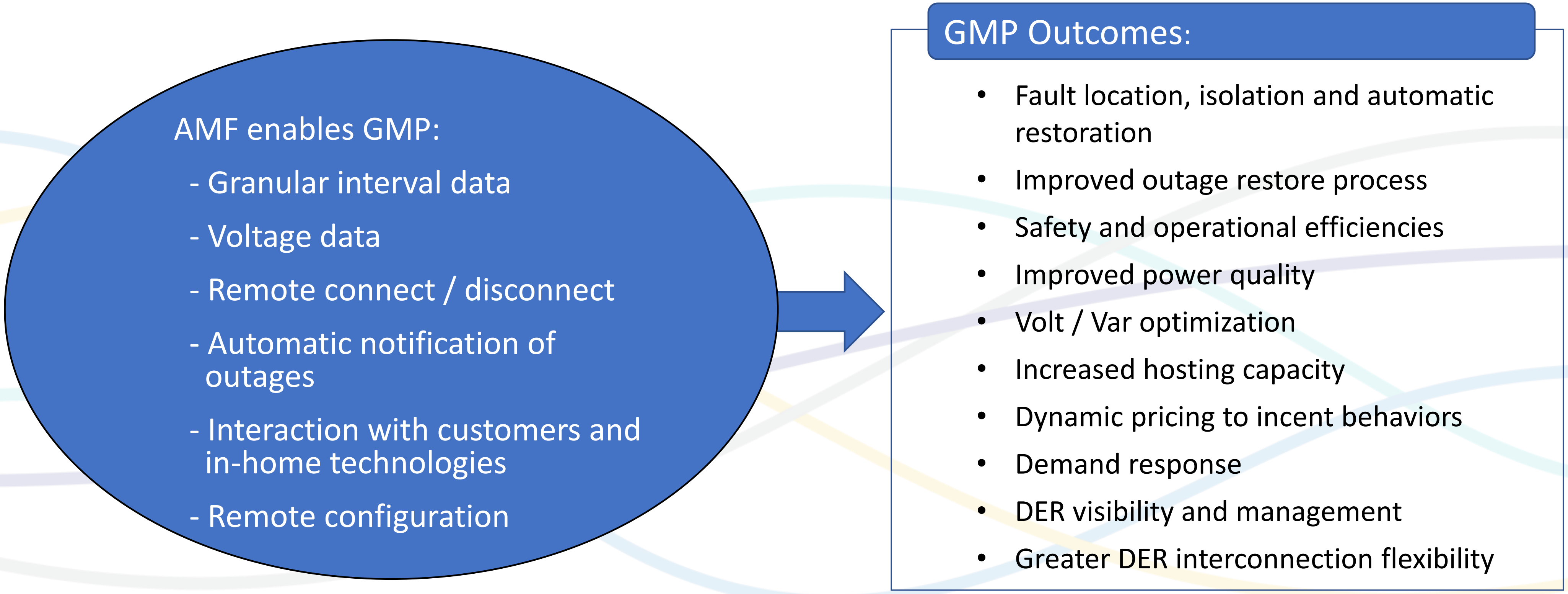
Preliminary Reduced Outage Frequency Benefits		
As of November 8, 2022	Nominal ($M)	NPV ($M)
Reduced Outage Frequency Benefits	$ 413	$ 283

Assumptions

- System Average Interruption Frequency Index (SAIFI) first quartile performance achievable with proposed advanced reclosers and FLISR, up to a 30% reduction.
- Used DOE's Interruption Cost Estimation (ICE) tool to estimate value of reducing the number of interruptions
- Annual value based on number of customers in Rhode Island Energy's area approximately $27M in $2022
- Inflated at 1.86% (average inflation 2012-2021) and discounted at 3% (Societal discount rate)

AMF Linkage to GMP and Next Steps

AMF Enables the GMP: Coordinated Business Plans



AMF enables GMP:

- Granular interval data
- Voltage data
- Remote connect / disconnect
- Automatic notification of outages
- Interaction with customers and in-home technologies
- Remote configuration

GMP Outcomes:

- Fault location, isolation and automatic restoration
- Improved outage restore process
- Safety and operational efficiencies
- Improved power quality
- Volt / Var optimization
- Increased hosting capacity
- Dynamic pricing to incent behaviors
- Demand response
- DER visibility and management
- Greater DER interconnection flexibility

AMF and GMP business plans coordinate benefit and timing assumptions

Wanda

Filing discussion and next steps

AMF and GMP Business Case Linkages

Benefit Quantification

- Volt VAR Optimization / Avoided Sensors
  - AMF .5% energy savings; GMP 2% energy savings
- Outage Management
  - AMF notification automation; GMP dispatch efficiencies and reliability improvements
- Time Varying Rates
  - AMF 20% opt in
  - GMP brings additional participation with locational value proposition

Benefit Timing Considerations

- Software availability
- AMF data availability
- GMP Automation availability

Functionality

- AMF brings foundational and enhancing capability to GMP

Grid Modernization: Why? Why NOW??

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- Existing system provides **little distribution operator visibility** and limited automated control
- **Accelerated grid transformation needed** for 21st century to manage increased system complexity. Caused by increased DER penetration and electrification reinforced by State clean energy policy.
- Successful operations requires comprehensive **situational awareness** and more **system control**
- Greatest benefit from **combined AMF and GMP** functionality
- Grid Modernization study tested system limits and identify solutions to meet Act on Climate Mandates resulted in a **no regrets decision for GMP investments** with very positive BCA (preliminary) as the most the most economical alternative
- The **time is NOW:** Reliability trends, Nasonville lessons, renewable interconnection queue, hidden load from switching, high-end DER forecast adoption, clean energy mandates, ADMS Basic availability, increased GMP capability from PPL experience
- **Impacts of a delay:** opportunity cost, customer service, safety, reliability, increased costs, affordability risks, supply chain, delayed benefits, ability to enable clean energy
- **Included in FY24 ISR:** accelerating GMP investments, which are foundational and the path of no-regret
- GMP Business Case: includes long-range studies, **foundational GMP investments**, GMP roadmap and BCA

Next Steps

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1. Finalize BCA
2. Align Foundational GMP investments with ISR
3. Finalize Business Case
4. PST Final Meeting December
5. File GMP consistent with ASA requirements

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Attachments

Business Use

Transmission Studies and Sensitivity

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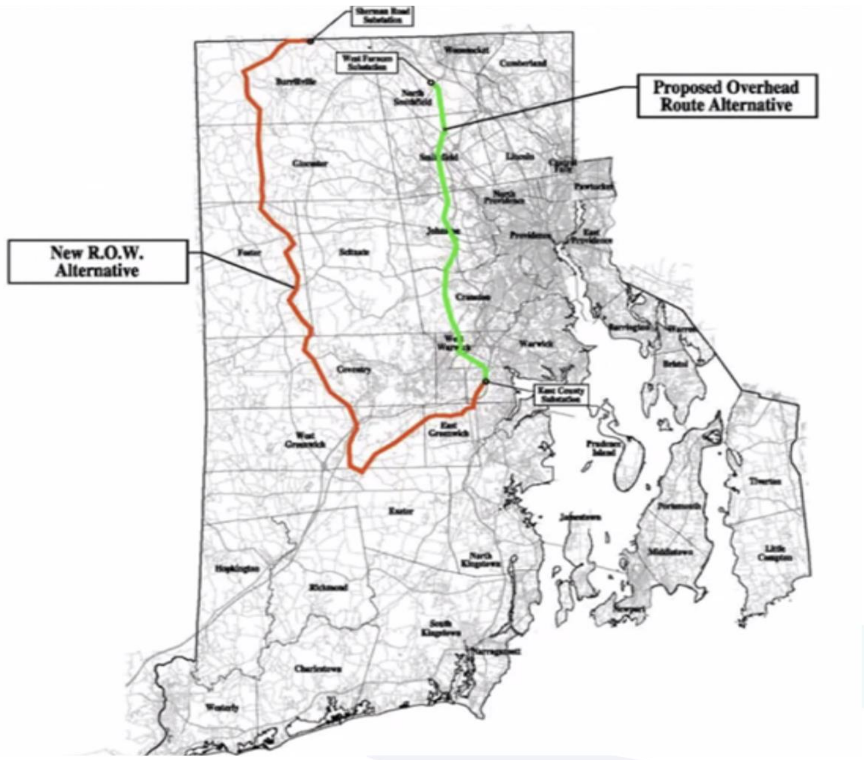
System Enhancements Being Studied

Recognizing there is a significant increase in load over the period and more flexibility is needed…

- Reviewing system alternatives that can accommodate most economically
- Transmission alternatives that are being studied are shown (preliminary)
- Many potential benefits to Rhode Island



Combined AMF + GMP advance core objectives

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Advanced Metering Functionality (AMF)	Grid Modernization Plan (GMP)
Existing meters are at end of life and must be replaced; advanced meters result in **lifetime savings for customers**.	Advanced meters provide the data backbone to better utilize & operate grid infrastructure, improve service & reliability, & **right-size build-out to reduce long-term costs**.
Near real-time/highly granular data is necessary to operate the grid while **affordably meeting our climate mandates**.	**Easier and less costly to interconnect** renewable energy, energy storage, electric transportation and heat.
Improved data and greater control are necessary to support **safe, reliable service** now and into the future.	Remote operation and refined control means improved **safety and protection** for workers and infrastructure.
Grid operators will know **exactly when and where outages occur**; customers no longer need to report power is out.	Software can automatically re-route electricity to reduce outages in our **'self-healing' grid**.
Customers can access **data to manage energy use** and utility bills resulting in greater affordability and superior customer experience.	Fewer shorter outages and managed more affordable costs are primary **drivers of customer satisfaction**.

Division 1-37

Request:

Discuss the Company's rationale for categorizing GMP as non-discretionary. Specifically, why is the Company including elements of programs that were previously implemented as discretionary, such as relay and recloser replacements, as non-discretionary?

Response:

The Company's existing electric distribution system provides little distribution operator visibility and limited automated control. Accelerated grid transformation is needed to manage system complexity that is caused by increased distributed energy resource ("DER") penetration and electrification already occurring and by anticipated growth. Because of the current characteristics of the Rhode Island Energy electric distribution system, the Company believes it is not possible to continue to provide service reliably and safely with the status quo. Grid Modernization Plan ("GMP") investments that are designated as such in the Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan are needed now for safe and reliable operations; therefore, these investments are non-discretionary.

The Company may have included elements of the GMP as discretionary in the past; however, now they are needed as components that work together holistically as GMP foundational investment to provide the highest overall net benefits to achieve functionality required to meet unmet operational, customer, and clean energy needs. Furthermore, during its review of the Company's FY 2021 Electric ISR Plan, the Commission found that similar investments necessary to operate the electric distribution system should be considered non-discretionary. Specifically, the Commission unanimously voted "to approve [the Company's] FY 2021 Electric Infrastructure, Safety and Reliability Plan with one modification. The $2 million proposed for Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors and Advanced Recloser Controls in the Strategic DER Program should be moved from the system capacity performance category to the non-discretionary Customer Request/Public Requirements category for cost socialization."[1]

There are many factors that lead to the conclusion that the GMP foundational investment is urgent. These factors include the following:

- Deteriorating reliability trends;
- Lengthening distributed generation interconnection queue;

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[1] See Minutes of Open Meeting Held on March 17, 2020, Docket No. 4995, at: https://opengov.sos.ri.gov/Common/DownloadMeetingFiles?FilePath=\Minutes\439\2020\362425.pdf

- Increased operational risk because of the presence of hidden load during switching, voltage variability, and lack of situational awareness as evidenced during the August 2022 Nasonville event;
- High DER adoption rates that are reinforced with the State of Rhode Island's Climate Mandates[2] and various incentives; and
- A compromised supply chain, resulting in imminent delays for material availability.

The prudency of the decision to accelerate GMP investments is reinforced by having ADMS Basic[3] operational software available at the TSA exit, which results in early benefits that are closely timed with the installation of advanced field devices and having increased confidence in the Rhode Island deployment plans based on PPL Electric's experience in Pennsylvania over the last decade.

It is urgently important to act now to move the GMP foundational investments forward so the electric distribution system does not further hinder system reliability, customer empowerment, or achievement of the Climate Mandates and does not create higher costs in the long run. By delaying the GMP foundational investments, there will be a wide range of impacts including opportunity cost, customer service, safety, reliability, increased costs, affordability risks, added supply chain risks, delayed benefits, and challenges to enable clean energy.

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[2] The term "Climate Mandates" refers to the State's aggressive policy mandates to transition to renewable energy generation and net zero greenhouse gas emissions: (1) The 2021 Act on Climate, which sets forth enforceable, statewide, and economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45 percent below 1990 levels by 2030, 80 percent by 2040, and to achieve net-zero emissions by 2050; and (2) the 2022 amendments to the Renewable Energy Standard, which further accelerate the shift to renewable energy resources by requiring 100 percent of electricity used in the State to be generated by renewable energy resources by 2033.

[3] PPL Corporation ("PPL") is bringing a basic ADMS system (referred to herein as "ADMS Basic") to Rhode Island Energy as a condition of PPL Rhode Island Holdings, LLC's acquisition of 100 percent of the outstanding shares of common stock of The Narragansett Electric Company (the "Acquisition") and as part of Rhode Island Energy's transition to PPL's systems. ADMS Basic is the ADMS platform PPL currently has in place for PPL Electric Utilities Corporation ("PPL Electric") in Pennsylvania and which Rhode Island Energy will have in place for its operations upon exit from the Transition Services Agreement with National Grid USA Service Company, Inc. ("TSA"). As part of the Acquisition approval, PPL committed that it would not seek recovery from customers of any transition costs. Part of that transition includes bringing ADMS Basic to Rhode Island Energy. Accordingly, PPL is providing the ADMS Basic platform to Rhode Island Energy, the allocated costs of which will not be recovered from Rhode Island customers. ADMS Basic is an enhancement from the National Grid distribution management system. PPL and Rhode Island Energy plan to propose enhancements to ADMS Basic (which are not a part of the transition) to increase functionalities and benefits. The defined term "ADMS Basic" refers specifically to the software that PPL is providing to Rhode Island Energy as part of the transition.

Division 1-38

Request:

What is the value and basis for the value of the basic ADMS operating functionality that RIE states is being provided to RIE customers at "no cost." (page 37)? What is the estimated cost to fully implement proposed ADMS on the RIE system? Provide a breakdown by year, by component, and by capital versus O&M.

Response:

Please see the Company's response to Division 1-37. As the Company first discussed with the AMF/GMP Subcommittee of the Power Sector Transformation Advisory Group in August 2022 and again in November 2022 at which time the Company provided an updated roadmap, the Company will be offering a range of functionalities that is enabled by ADMS system operating software. Rhode Island Energy expects to have the ADMS estimated cost and breakdown by early December 2022 and intends to include them in the Grid Modernization Plan.

Division 1-39

Request:

All previous ISR Plan projects and programs included justifications. Explain why RIE believes the GMP budget does not require a comprehensive set of justifications.

Response:

Rhode Island Energy believes the Grid Modernization Plan ("GMP") requires a comprehensive set of justifications and has conducted the justification analysis within its GMP. Early indications from reliability trends, and other reasons as noted in the Company's response to Division 1-37, demonstrate the urgency of making the GMP foundational investments. Because of the urgency, the budget for these investments has been included in the Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan, which will align with the GMP the Company plans to file with the Public Utilities Commission by the end of the year.

Because the FY 2024 Electric ISR Plan and the GMP filings are occurring in parallel, Rhode Island Energy has been communicating the justifications for the GMP investments with the AMF/GMP Subcommittee of the Power Sector Transformation ("PST") Advisory Group during meetings held in July, August, October, and November 2022. The Company shared preliminary Benefit-Cost Analysis ("BCA") results with the PST Advisory Group in November 2022. Using four benefits that would be achievable with the GMP foundational investments resulted in a strong BCA ratio that was well above 1.0, which indicates that the GMP foundational investments are viable. Further justifications will be included in the Company's GMP filing using a BCA analysis that complies with the Public Utilities Commission's Docket No. 4600 Framework.

Prepared by or under the supervision of: Wanda Reder

Division 1-40

Request:

Explain in detail how the Division and PUC can evaluate the legitimacy of the GMP budget absent any GMP to evaluate?

Response:

Since July 2022, Rhode Island Energy has been sharing its Grid Modernization Plan ("GMP") investments with the AMF/GMP Subcommittee of the Power Sector Transformation Advisory Group, the Division of Public Utilities and Carriers (the "Division"), and/or the Public Utilities Commission ("PUC") in various meetings and technical sessions to inform stakeholders of the GMP developments and to solicit their input. This engagement process has provided stakeholders with a preview of the approach the Company used for the GMP assessment and the legitimacy of the recommendations. The Company plans to file the GMP with the PUC at the end of the year at which time the Division will also receive the GMP. The Company plans to include in the filing a comprehensive study to achieve the State of Rhode Island's Climate Mandates[1] with and without grid modernization. The study results will indicate that the path forward with grid modernization is the only viable solution. The resulting GMP foundational investments will be analyzed using the PUC's Docket No. 4600 Framework, which will provide the necessary information to evaluate the legitimacy of the GMP budget.

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[1] Please see the Company's response to Division 1-37, footnote 1.

Division 1-41

Request:

What support does RIE have for the GMP proposed budget?

Response:

The support that Rhode Island Energy has for the Grid Modernization Plan ("GMP") budget proposed in the Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan includes potential benefits and costs for GMP collected from (1) conducting workshops with key internal and external personnel; (2)reviewing and participating in industry and government forums; (3) gathering data and researching the GMP scope and investment approach used in other plans; (4) gathering relevant use cases across the industry; (5) evaluating pertinent PPL Corporation operational data pre- and post-GMP implementation; (6) conducting extensive independent research on different aspects of the scope of benefits and costs; (7) calculating benefit cost ratios by developing key benefits of GMP and applying well-established Benefit-Cost Analysis methodologies and input assumptions; and (8) conducting and validating detailed state-wide modeling of all Rhode Island Energy feeders for every hour of targeted study years through 2050 to compare alternative investments needed to meet the State of Rhode Island's Climate Mandates[1].

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[1] Please see the Company's response to Division 1-37, footnote 1.

Prepared by or under the supervision of: Wanda Reder