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Rhode Island Energy™
a PPL company

March 5, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-48-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Responses to PUC Data Requests – Set 9 (Complete Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's complete set of responses to the Public Utilities Commission's ("PUC") Ninth Set of Data Requests in the above-referenced matter.

This transmittal contains the Company's responses to data requests PUC 9-20 and PUC 9-21.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-48-EL Service List

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-48-EL Service List

PUC 9-1
Performance Metrics

Request:

Regarding RIE's response to Division 3-3, the respondent states, "Please note that the dark gray bars represent the category mean with ½ of all respondents preforming above that target."

a. Please indicate who the "respondents" are.

b. Does the answer indicate the mean respondent performance is equal to the median respondent performance?

Response:

a. The "respondents" are technically the customers who answered the survey. To clarify the response to Division 3-3, it is ½ of the companies that serve the respondents (customers who answered the survey) that are performing above target.

b. Although they may be close, the response does not indicate the mean (average) respondent performance is equal to median (middle number) respondent performance.

Prepared by or under the supervision of: Ryan Constable

PUC 9-2
Performance Metrics

Request:

On Bates page 15 of the Panel Testimony, the witnesses state, "[t]he Company has established an internal goal of achieving top first quartile SAIFI performance when compared to peer utilities, which is better performance than required under the PUC's performance penalty criteria."

a. Please specifically state what the definition of "first quartile SAIFI performance when compared to peer utilities" means.
b. Who determines if the Company is successful?
c. How does this entity make the determination?

    i. What data is collected?
    ii. How is it validated?
    iii. What adjustments and normalizations are made?
    iv. How is the peer group chosen?
    v. Can any of the responses to subpart i through iv change, and if so, who determines that, how is that determined, and how is it reported?

Response:

a. The definition of "first quartile SAIFI performance when compared to peer utilities" means that the Company's performance is in the top 25% of all utilities within the IEEE Distribution Reliability Working Group (DRWG) Benchmarking, national (medium sized utility) and regional (northeast) categories.

b. The ranking is determined by the IEEE DRWG. If this results in Rhode Island Energy ranking in the top 25%, the Company will deem its performance successful for this metric. There are other metrics the Company will evaluate before it determines that it has achieved complete success for its reliability performance goals, as reflected in the Company's response to PUC 6-15.

c. The IEEE DRWG ranks the utilities based on the interruption data provided.

    i. Each utility's interruption data is collected.

    ii. The data is validated by the IEEE working group on the interruption information provided. The IEEE DRWG strives to have differences minimized and uses clear rules on exclusions. This standardizes the data set across all companies.

PUC 9-2, page 2
Performance Metrics

iii. The Company is not aware of any adjustments or normalizations made by the working group other than the standardization rules noted in part ii.

iv. Peer groups are assigned by region and size. The northeast region is defined by the working group as New York and New England. A medium sized utility is considered a utility with greater than 100,000 customers and less than 1,000,000 customers.

v. Each utility has its own data collection methods. The IEEE DRWG notes that companies may not report all forms of outages, due to data collection issues. Rhode Island Energy recognizes that subpart i. can change if the utility changes its data collection methods. The Company is not aware if or how subparts ii. through iv. can change.

Prepared by or under the supervision of: Ryan Constable

PUC 9-3
Performance Metrics

Request:

Has the Company surveyed its customers to learn what utilities and businesses their customers actually compare them to?

Response:

No, the Company has not directly surveyed its customers to learn what utilities and businesses the customers actually compare Rhode Island Energy to.

As described in the Company's response to PUC 6-15, however, the Company includes consideration of the J.D. Power Electric Utility Residential Customer Satisfaction Study, focusing on Power Quality and Reliability, in its metrics to determine performance. Although this survey does not detail what the customers are comparing the Company to, Rhode Island Energy views this survey to be a reasonable method to survey customer opinion.

Prepared by or under the supervision of: Ryan Constable

PUC 9-4
Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

Did the Company use the web-based ICE Calculator Value of Reliability Improvement module (ICE Module) for its analyses of the value if outage improvements for DARP, ERR, and CEMI, or did the Company use the customizable workbook version of the ICE Module?

a. If the Company used the customizable version of the ICE Module:

    i. Were any adjustments made to any workbook tabs other than the "Main" tab?

    ii. Please explain (separately for DARP, ERR, and CEMI programs) the adjustments and the supporting rationale.

    iii. If the Company used the web version of the ICE Module, please provide any post hoc adjustments to the default model inputs, such as the ratio of small C&I customers to large C&I customers (reference is made to the "Reliability" tab of the Attachment DIV 7-7).

Response:

The Company used the web-based ICE Calculator Value of Reliability Improvement module (ICE Module) for its analyses of the value if outage improvements for DARP, ERR, and CEMI.

a. If the Company used the customizable version of the ICE Module:

    i. The Company did not use the customizable workbook version of the ICE Module.

    ii. The Company did not use the customizable workbook version of the ICE Module. The Company provided and explained all web-based ICE Calculator assumptions in the responses to Division 3-27, 3-28, 4-34, 4-35, 7-7, and PUC 3-19.

    iii. The Company did use the web version of the ICE Module, and no post hoc adjustments were made. The Company notes that the number of customers per category need to be directly entered. The Company's response to PUC 3-19 shows the number of customers per category.

Prepared by or under the supervision of: Ryan Constable

PUC 9-5

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

What is the Panel's understanding of:

a. The correlation between backup generation and the value of avoided outages assumed in the ICE Module?

b. The default inputs representing backup generation status assumed by the ICE Module for Rhode Island?

Response:

a. The Company is aware there are backup generation assumptions within the ICE Module. The Company did not change these assumptions and has no specific understanding of the correlation between generation and the value of avoided outages assumed in the ICE Module. The Company assumes that the correlation has two parts; 1) the backup generation avoids customer costs which would reduce the value of avoided outages, and 2) the backup generation has a cost to run which would increase the value of avoided outages.

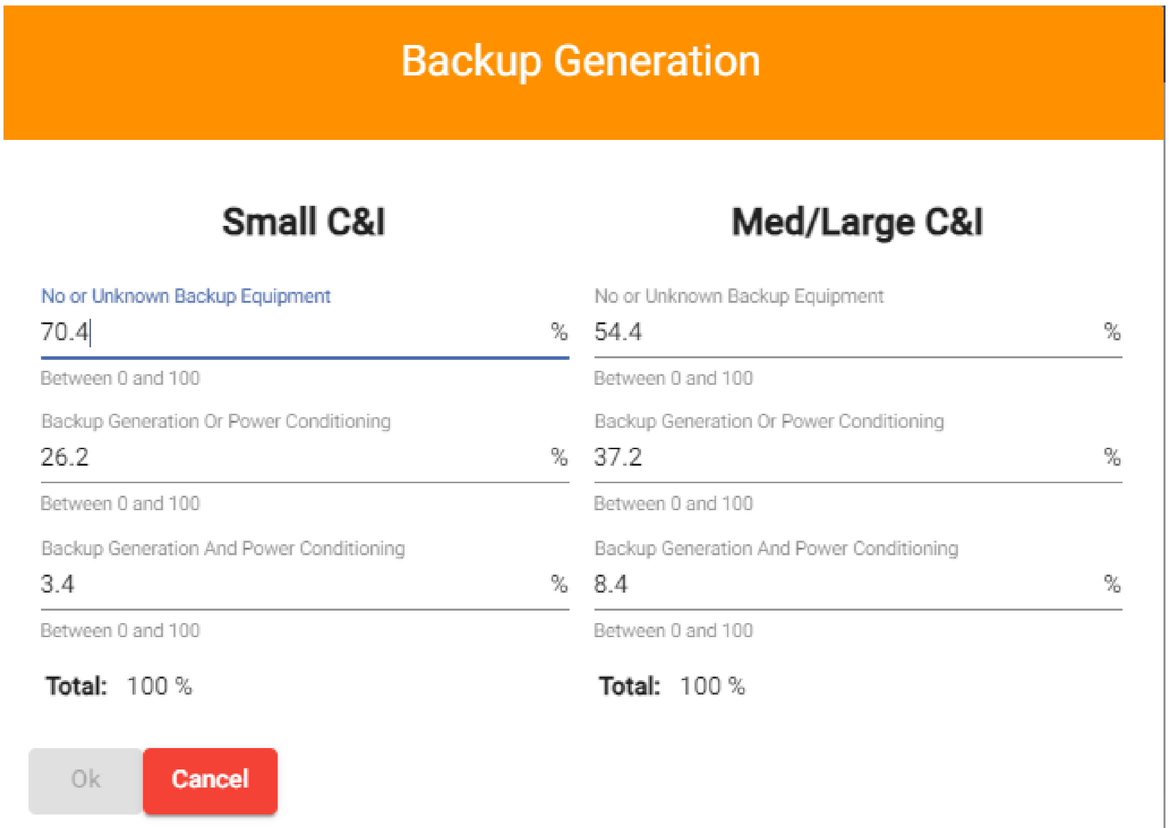
b. The web-based ICE Module includes backup generation assumptions as shown in Figure PUC 9-5 below.

PUC 9-5, page 2

Value of Reliability Improvements (ERR, CEMI, and DARP)

Figure PUC 9-5

ICE Module Backup Generation Assumptions



Prepared by or under the supervision of: Ryan Constable

PUC 9-6

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

Referencing Bates page 199, does the 1.05 BCA of the DARP indicate that Company has proposed investing $16.77M to gain $17.672M of avoided outage costs over 20 years? If so, is 100% of the projected benefit based on the output of the ICE Module?

Response:

Yes, the 1.05 BCA of the DARP does indicate that the Company has proposed investing $16.77 million to gain $17.672 million of quantified benefits over 20 years, and 100% of those projected quantified benefits is based on the output of the ICE Module. This calculation, however, is based on conservative assumptions, including, specifically, a high valuation of a 2-minute outage, which results in a lower quantified benefit value, which is reflected in the calculations in Attachment DIV 4-34 Additionally, the DARP provides qualitative benefits in safety and system performance that should also be considered.

Prepared by or under the supervision of: Ryan Constable

PUC 9-7

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

Regarding RIE's use of the ICE Module, RIE states in a number of responses to Division data requests that RIE originally used a "simplified" 20-year analysis that assumed 100% of the annual avoided outage value benefits to DARP and CEMI programs began in the first year of the program even though investments and actual improvements would occur over multiple years. RIE also describes in multiple data responses a "staggered" analysis, recognizing benefits in these programs will grow over the planned investment years. For example, see RIE's response to Division 4-34.

a. Does the staggered model also add additional years to the life of the program equal to the years of staggering? Please explain, making reference to the analyses provided in Attachment DIV 4-34.

b. If the answer to part a is "yes," please explain if the staggered analysis assumes the initial years of the program investment extend past 20 years.

c. If the answer to part b is "yes," please provide the rational for this assumption.

d. Does RIE have an analysis that treats each year of the DARP or CEMI programs as an individual 20-year analysis and then sums the individual years for a total program BCR? If so, please provide the results and supporting documentation.

Response:

a. The staggered model adds additional years to the life of the program equal to the years of staggering. Attachment DIV 4-34-1, which was provided in Excel format, includes a sheet reflecting the staggered analysis that reflects the additional years of life for the program resulting from the staggering.

b. Yes, the staggered analysis would extend the evaluation of the initial year investments beyond 20 years.

c. The life of the investments is greater than 20 years. Reclosers can have a life of 25 years and other distribution assets installed for reliability reasons can have asset lives of 30 to 40 years. A 20-year assumption results in a conservative valuation and avoids the need for complex asset life analysis.

PUC 9-7, page 2

Value of Reliability Improvements (ERR, CEMI, and DARP)

d. The staggered analysis was done for the CEMI and DARP programs as shown in the Company's response to Division 3-25 and Attachment DIV 4-34-1 to the Company's response to Division 4-34.

PUC 9-8

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

Regarding RIE's response to Division 4-21, RIE stated, "The SAIFI and SAIDI improvements associated with the ERR program have not been calculated." The response to Division 7-7 appears to rely on a 25% reduction to both SAIDI and SAIFI.

a. Please reconcile these two pieces of information.

b. Please confirm whether the input post-investment SAIFI used in the analysis was 1.305, and what percent reduction this represents (e.g., 25.1%).

Response:

a. The response to Division 4-21 was done prior to the Docket 4600 analysis performed for the ERR program. The response to Division 7-7 was completed after the Docket 4600 analysis performed for the ERR program.

b. The post-investment SAIFI input used in the analysis was 1.305, which represents a 25.086% reduction.

Prepared by or under the supervision of: Ryan Constable

PUC 9-9

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

On Bates 165 of Book 1, RIE explains how it arrived at a post-investment reduction in outage events, indicating, "Of these mainline events approximately 50% can be addressed by sectionalization. Assuming the recloser was located to roughly divide the customers within the existing protection zone, the recloser sectionalization would reduce the frequency by 50%."

a. Please provide the supporting data, analysis, or rationale behind the declaration that approximately 50% of mainline events can be addressed by sectionalization.

b. In analyzing the benefits of DARP and/or ERR did RIE also assume a 25% improvement in SAIDI?

c. If the answer to part b is "yes" for either program, does this mean that RIE assumed that the 50% of mainline events that can be addressed by sectionalization also account for 50% of the duration of outages? If so:

   i. Please provide the support for this assumption.
   ii. Please explain if this is consistent with RIE's presentation of the ICE Module results for the CEMI analysis presented on Bates page 182 of Book 1.

Response:

a. The Company did not rely on any data or analysis to arrive at the determination that approximately 50% of mainline events can be addressed by sectionalization. The rationale for that declaration is embedded in the assumption that follows it. If a recloser is installed in a location that approximately splits the number of customers in an existing protection zone in half, then assuming the recloser operates as expected, an outage that occurs on one side of the new recloser within that protection zone will no longer reach the customers on the other side of that new recloser – thus reducing the number of customers experiencing that outage by approximately 50%. Extrapolating that the number of mainline events that occurred within that protection zone remains constant, the frequency of outages experienced by the customers within that protection zone also would be reduced by approximately 50% because each mainline event within that protection zone would only be experienced by approximately 50% of the customers.

PUC 9-9, page 2

Value of Reliability Improvements (ERR, CEMI, and DARP)

b. A 25% improvement in SAIFI will result in a 25% improvement in SAIDI, however, no improvement in outage duration was assumed.

SAIFI = Customer Interrupted / Customers Served
SAIDI = Customers Interrupted * Outage Duration / Customers Served

If customers interrupted is reduced by 25%, both equations reduce by 25%

c. No, the Company did not assume that the 50% of mainline events that can be addressed by sectionalization also account for 50% of the duration of outages. See the response to part b.

PUC 9-10

Value of Reliability Improvements (ERR, CEMI, and DARP)

Request:

On Bates page 182 of Book 1, it appears RIE's ICE Module analysis of the benefits of CEMI assumes a hypothetical circuit with a SAIFI improving from 4 to 1 and a CAIDI held constant. Please confirm the SAIDI is assumed to improve from 960 to 240. Please also explain if the assumed improvement in SAIFI and SAIDI are based on any observed data, or if it based on a determined assumption that RIE will reach its performance goal on these circuits?

Response:

The SAIDI is assumed to improve from 960 to 240. An explanation of the outage duration of 240 minutes is explained in the Company's response to Division 3-24. The reduction from 4 to 1 outages is based on an assumption the program will reach its performance goal. However, as described in the Company's response to Division 3-9, this should be considered a reduction of 3 outages and not necessarily a reduction to 1 outage.

Prepared by or under the supervision of: Ryan Constable

PUC 9-11
Federal Grant Applications

Request:

Regarding the proposed spending budget in FY25 ISR Plan or any investments described in the 5-year budget, including the fiber program:

a. Please provide a list of any such spending for which RIE submitted a proposal to the federal government for any form of financial support, the federal program applied to, the nature of the financial support requested, and the status of the application.

b. Please provide a copy of any such proposals.

Response:

a. The Narragansett Electric Company, d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy") has submitted two proposals to the federal government for financial support (i.e., grant funding), both through DE-FOA-0002740 managed by the U.S. Department of Energy's Grid Deployment Office with funds appropriated by the Infrastructure Investment and Jobs Act ("IIJA"), also known as the Bipartisan Infrastructure Law ("BIL"). The funds offered through this funding opportunity are in the form of a grant with a required cost share.

   One proposal was named *Smart Grid for Smart Decarbonization* and includes advanced reclosers, smart capacitors and regulators, digital relays, and fiber communications, along with other grid modernization software. This proposal was selected for award and continues to be in the award negotiation phase. The Company anticipates the award negotiation phase to complete over the next month. Pending successful completion and the details of the finalized award, the Company intends to include the portion of the award that can be applied to FY 2025 investments within its annual reconciliation of ISR funding.

   The other proposal, which was not selected for award, included the Merton #51 Equipment Replacement, the Tiverton Sub (D-Line), a portion of the Chase Hill Common Items, and the Staples #112 Reliability 112W43 projects that overlap with FY2025 ISR.

   With the intent of supporting the clarity, completeness, and ease of reference in the public record, the following list consolidates filings regarding federal funding across dockets:

PUC 9-11, page 2

Federal Grant Applications

i. Direct Testimony of Electric ISR Witness Panel, Bates Page 18 at lines 4-16
ii. Proposed FY2025 Electric ISR Plan, Bates Page 77
iii. The Company's response to Division 7-8 in Docket No. 23-48-EL
iv. The Company's response to Division 4-25 in Docket No. 23-48-EL
v. The Company's response to PUC 1-1 in Docket No. 22-56-EL

b. Please refer to Attachment PUC 9-11-1 for the complete Funding Opportunity Announcement to which Rhode Island Energy applied for federal funding (proposals were submitted in March-April 2023). Please refer to Attachment PUC 9-11-2 and Attachment PUC 9-11-3 for the Technical Volumes submitted for each of the two Topic Areas in the Funding Opportunity Announcement to which Rhode Island Energy applied. Attachment PUC 9-11-2 is the Technical Volume for Topic Area 1: Grid Resilience; Rhode Island Energy was not selected for award for this proposal. Attachment PUC 9-11-3 is the Technical Volume for Topic Area 2: Smart Grid. Rhode Island Energy was selected for award negotiations for its proposal to Topic Area 2; the specifics of the award may be subject to change pending the award negotiation process, which is ongoing at this time.

FINANCIAL ASSISTANCE
FUNDING OPPORTUNITY ANNOUNCEMENT

Department of Energy (DOE)
Grid Deployment Office (GDO)
Office of Clean Energy Demonstrations (OCED)

BIL – Grid Resilience and Innovation Partnerships (GRIP)

Funding Opportunity Announcement (FOA) Number: DE-FOA-0002740
FOA Type: Amendment 000007
Assistance Listing Number: 81.254

FOA Amendment 000007 Issue Date:	04/11/2023
1st Informational Webinar:	11/29/2022 2:00pm ET
2nd Informational Webinar:	02/08/2023 2:00pm ET
3rd Informational Webinar	02/27/2023 1:00pm ET
4th Informational Webinar	02/28/2023 1:00pm ET
Additional Webinars	To Be Announced*
Submission Deadline for Concept Papers (Topic Area 1):	12/16/2022 5:00pm ET
Submission Deadline for Concept Papers (Topic Area 2):	12/16/2022 5:00pm ET
Submission Deadline for Concept Papers (Topic Area 3):	01/13/2023 5:00pm ET
Submission Deadline for Full Applications (Topic Area 1):	04/06/2023 5:00pm ET
Submission Deadline for Full Applications (Topic Area 2):	03/17/2023 5:00pm ET
Submission Deadline for Full Applications (Topic Area 3):	05/19/2023 5:00pm ET
Expected Date for DOE Selection Notifications (Topic Area 1):	Summer 2023
Expected Date for DOE Selection Notifications (Topic Area 2):	Summer 2023
Expected Date for DOE Selection Notifications (Topic Area 3):	Fall 2023
Expected Timeframe for Award Negotiations (Topic Area 1):	Fall 2023
Expected Timeframe for Award Negotiations (Topic Area 2):	Fall 2023
Expected Timeframe for Award Negotiations (Topic Area 3):	Winter 2023

- Applicants must submit a Concept Paper by 5:00pm ET on the due date listed above to be eligible to submit a Full Application.

- *See Section VIII.P for more information on additional webinar(s).

- To apply to this FOA, applicants must register with and submit application materials through Grants.gov at https://www.grants.gov/.

- Applicants must designate primary and backup points-of-contact with whom DOE will communicate to conduct award negotiations. If an application is selected for award negotiations, it is not a commitment to issue an award. It is imperative that the applicant/selectee be responsive during award negotiations and meet negotiation deadlines. Failure to do so may result in cancelation of further award negotiations and rescission of the selection.

Registration Requirements

There are several one-time actions that must be completed before submitting an application in response to this Funding Opportunity Announcement (FOA) (e.g., register with the System for Award Management (SAM), obtain a Unique Entity Identifier (UEI) number, register with Grants.gov, and register with FedConnect.net to submit questions). It is vital that applicants address these items as soon as possible. Some may take several weeks, and failure to complete them could interfere with an applicant's ability to apply to this FOA.

- **SAM** – Applicants must register with SAM at https://www.sam.gov/ prior to submitting an application in response to this FOA. Designating an Electronic Business Point of Contact (EBiz POC) and obtaining a special password called an MPIN are important steps in SAM registration. Failure to register with SAM will prevent your organization from applying through Grants.gov. The applicant must maintain an active SAM registration with current information at all times during which it has an active Federal award or application under consideration. More information about SAM registration for applicants is found at: https://www.fsd.gov/gsafsd_sp?id=gsafsd_kb_articles&sys_id=650d493e1bab7c105465eaccac4bcbcb .

  NOTE: If clicking the SAM links do not work, please copy and paste the link into your browser.

  Due to the high demand of SAM registrations and UEI requests, entity legal business name and address validations are taking longer than expected to process. Entities should start the SAM and UEI registration process as soon as possible. If entities have technical difficulties with the SAM registration or UEI validation process they should utilize the HELP feature on SAM.gov. SAM.gov will work entity service tickets in the order in which they are received and asks that entities not create multiple service tickets for the same request or technical issue. Additional entity validation resources can be found here: GSAFSD Tier 0 Knowledge Base - Validating your Entity**.**

- **UEI** – Applicants must obtain an UEI from the SAM to uniquely identify the entity. The UEI is available in the SAM entity registration record.

  NOTE: Subawardees/subrecipients at all tiers must also obtain an UEI from the SAM and provide the UEI to the Prime Recipient before the subaward can be issued.

- **Grants.gov** – Applicants must register with Grants.gov and set up your WorkSpace. You cannot submit an application through Grants.gov unless you are registered. Please read the registration requirements carefully and start the process immediately.

  1) The Authorized Organizational Representative (AOR) must register at: https://apply07.grants.gov/apply/OrcRegister .

2) An email is sent to the E-Business (E-Biz) POC listed in SAM. The E-Biz POC must approve the AOR registration using their MPIN from their SAM registration.

More information about the registration steps for Grants.gov is provided at: https://www.grants.gov/web/grants/applicants/registration.html.

In addition:

- Add a Profile to a Grants.gov Account: A profile in Grants.gov corresponds to a single applicant organization the user represents (i.e., an applicant) or an individual applicant. If you work for or consult with multiple organizations and have a profile for each, you may log in to one Grants.gov account to access all of your grant applications. To add an organizational profile to your Grants.gov account, enter the UEI for the organization in the UEI field while adding a profile. For more detailed instructions about creating a profile on Grants.gov, refer to: https://www.grants.gov/web/grants/applicants/registration/add-profile.html .

- *EBiz POC Authorized Profile Roles*: After you register with Grants.gov and create an Organization Applicant Profile, the organization applicant's request for Grants.gov roles and access is sent to the EBiz POC. The EBiz POC will then log in to Grants.gov and authorize the appropriate roles, which may include the AOR role, thereby giving you permission to complete and submit applications on behalf of the organization. You will be able to submit your application online any time after you have been assigned the AOR role.

  NOTE: When applications are submitted through Grants.gov, the name of the organization applicant with the AOR role that submitted the application is inserted into the signature line of the application, serving as the electronic signature. The EBiz POC **must** authorize people who are able to make legally binding commitments on behalf of the organization as a user with the AOR role; **this step is often missed and it is crucial for valid and timely submissions**.

  For more detailed instructions about creating a profile on Grants.gov, refer to: https://www.grants.gov/web/grants/applicants/registration/authorize-roles.html .

  To track your role request, refer to: https://www.grants.gov/web/grants/applicants/registration/track-role-status.html .

Questions relating to the **registration process, system requirements, or how an application form works** must be directed to Grants.gov at 1-800-518-4726 or support@grants.gov.

- **FedConnect.net** – Applicants must register with FedConnect to submit questions. FedConnect website: https://www.fedconnect.net/

  All questions and answers related to this FOA will be posted on the FedConnect portal at: https://www.FedConnect.net and on the Grid Resilience and Innovation Partnerships (GRIP) Program web page at: Grid Resilience Innovation Partnership Programs | Department of Energy.

  See Section IV for Application and Submission Information (including how to create a WorkSpace).

Amendments

Amend. No.	Date	Description of Amendment
000001	11/18/2022	This Amendment is to issue the initial version of the FOA. This version (Amendment 00001) supersedes the previous draft version that was released for public comment (the Draft). The Draft version is now obsolete. Applicants are advised to use Amendment 00001 to prepare the concept paper and full application.
000002	11/29/2022	This Amendment is to revise Section IV.D.xvi to replace the hyperlink to the Community Benefits Plan Scoring Rubric; to remove a reference to program-specific Community Benefits Plan Guidance; and to move the instructions for submitting the Community Benefits Plan to the end of the section. Text that is revised or newly incorporated with this amendment is highlighted in yellow.
000003	12/13/2022	This Amendment revises the following sections: • the Registration Requirements section and Section VII to include the GRIP web page as an additional resource for Applicants to view FOA questions and answers. • Section I.B.ii to include the GRIP web page as an additional resource for Applicants to view the Teaming Partner List and any updates to it. • Section II.A.ii to include additional funding information, including plans for issuing the second competitive funding opportunity for GRIP in Fiscal Year 2024. • Section IV.A. and IV.C. to clarify concept paper submission information. Text that is revised or newly incorporated with this amendment is highlighted in yellow.
000004	02/06/2023	The Amendment revises the following: • The FOA Cover Page and Section VIII.P to notify applicants that additional informational webinars are planned. Please see Section VIII.P for additional webinar information. • Section I.B and I.C to reflect that for Topic Area 1, new distribution lines below 69 kV, reconductoring, undergrounding and other upgrades to existing transmission infrastructure are considered eligible; and applications that include new transmission lines at or

		above 69 kV are not of interest. A correction to Footnote 40 was also made in this section. • Section IV.D.xvi to remove the hyperlink to the Community Benefits Plan Scoring Rubric. The Community Benefits Plan Scoring Rubric will no longer be available. • Section IV.D.xx to correctly reflect the reference to the Project Description and Assurances Document Template (PDAD) template as Appendix F. Text that is revised or newly incorporated with this amendment is highlighted in yellow.
000005	02/23/2023	The Amendment revises the following: • The FOA Cover Page and Section VIII.P to notify applicants that additional informational webinars are scheduled. Please see Section VIII.P for additional webinar information. • Section II.A.ii to correct the anticipated length of the period of performance. • Section IV.D.xx to add the text of the "Locations of Work" full application content requirement. The Locations of Work template is now available as an attachment to this announcement for use. Text that is revised or newly incorporated with this amendment is highlighted in yellow.
000006	03/20/2023	The purpose of this Amendment is to re-open the FOA to accommodate the submission of full applications to Topic Area 1 and Topic Area 3 *only*. See the FOA Cover Page for Application Due Dates and Times. Please note, the application period for Topic Area 2 is closed. There are no changes being made to the FOA document as a result of this amendment.
000007	04/11/2023	The purpose of this Amendment is to re-open the FOA to accommodate the submission of full applications to Topic Area 3 *only*. See the FOA Cover Page for Application Due Dates and Times. Please note, the application period is now closed for Topic Area 1 and Topic Area 2. This amendment also revises Section VII to increase the number of days for which questions and comments concerning this FOA shall be submitted, from 3 business days to not later than 5

		business days, prior to the application due date for Topic Area 3. Text that is revised or newly incorporated with this amendment is highlighted in yellow.

Table of Contents

I. Funding Opportunity Description

A. Background and Context

The Grid Deployment Office (GDO), in conjunction with the Office of Clean Energy Demonstrations (OCED), is issuing this Funding Opportunity Announcement (FOA). Awards made under this FOA will be funded, in whole or in part, with funds appropriated by the Infrastructure Investment and Jobs Act[1] (IIJA), also more commonly known as the Bipartisan Infrastructure Law (BIL).

The BIL is a once-in-a-generation investment in infrastructure, designed to modernize and upgrade American infrastructure to enhance U.S. competitiveness, driving the creation of good-paying union jobs, tackling the climate crisis, and ensuring stronger access to economic, environmental, and other benefits for disadvantaged communities (DACs). The BIL appropriates more than $62 billion to the Department of Energy (DOE)[2] including funding to support investments to build a clean and equitable energy economy that achieves pollution free electricity by 2035 and puts the United States on a path to achieve net-zero emissions economy-wide by no later than 2050"[3] to benefit all Americans. As new load and generation come online as the market moves in line with these goals, deploying the projects that will support a more resilient and reliable grid will be critical. At present, aging grid infrastructure leaves the grid increasingly vulnerable to attacks.[4] The increasing frequency of extreme weather events is leading to energy supply disruptions that threaten the economy, put public health and safety at risk, and can devastate affected communities all over the country.

Among other programs DOE has to support the grid, three BIL programs covered by this FOA – each with specific statutory requirements– will invest approximately $10.5 billion for the five-year period encompassing FY22 through FY26 to deploy technologies to increase grid reliability and resilience. The activities to be funded under this FOA support three BIL sections including 40101(c), 40107 and 40103(b).[5] Together DOE refers to these programs as the Grid Resilience and Innovation Partnerships (GRIP) program.

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[1] Infrastructure Investment and Jobs Act, Public Law 117-58 (November 15, 2021). https://www.congress.gov/bill/117th-congress/house-bill/3684. This FOA uses the more common name "Bipartisan Infrastructure Law".

[2] U.S. Department of Energy. November 2021. "DOE Fact Sheet: The Bipartisan Infrastructure Deal Will Deliver For American Workers, Families and Usher in the Clean Energy Future." https://www.energy.gov/articles/doe-fact-sheet-bipartisan-infrastructure-deal-will-deliver-american-workers-families-and-0

[3] Executive Order (EO) 14008, "Tackling the Climate Crisis at Home and Abroad," January 27, 2021.

[4] See ICF International, Electric Grid Security and Resilience: Establishing a Baseline for Adversarial Threats, at 26 (June 2016)

[5] 42 USC §18711(c); 42 USC §18712(b); 42 USC §17386

Principles of equity, justice, and advancing accessible good-paying jobs with the free and fair choice to join a union will guide implementation of this program, in alignment with the Administration's Justice40 Initiative and commitment to American workers. The Department commits to robust engagement and collaboration with States, U.S. Territories, and Indian Tribes, as well as with other interested stakeholders, including industry, unions, and local communities, for successful implementation of the GRIP program.

These BIL sections that make up the GRIP program are:

- Section 40101(c): Grid Resilience Grants
- Section 40107: Smart Grid Grants
- Section 40103(b): Grid Innovation Program

i. Program Purpose

Climate change is increasing the threats to our power system infrastructure. Disruptive weather events are more intense in terms of temperature extremes and precipitation and are becoming broader in scope and affecting larger areas at a time. Other climate impacts like droughts are long-lasting, compounding the potential impact of disruptive events and increasing other threats such as wildfires, floods, and mudslides. Previous methods and approaches to prepare for disruptions are no longer sufficient to meet the increasing threats to the power system due to climate change. Increasing interdependencies between critical infrastructure systems will continue to impact our power system.

With these trends in mind, building a more resilient and reliable grid is critical. Studies indicate a more resilient and reliable grid must inherently have the following characteristics: increased grid reliability and flexibility, the ability to easily interconnect new clean energy to enhance generation mix diversity, and improved system cost-effectiveness.[6] There is currently insufficient development of projects that will support these characteristics that are critical to reliability and resilience of the grid, particularly in projects that would achieve the following outcomes: 1) increasing transfer capacity between regions, 2) addressing the most consequential system needs and challenges that cause or contribute to the problematic and increasing interconnection queue time for clean energy, and 3) increasing supply of a geographically and technologically diverse sets of location-constrained energy resources to enhance resource adequacy and reduce correlated generation outages.[7] Therefore, DOE is eager to leverage federal dollars under the GRIP program to bring together state, Tribal,

[6] National Renewable Energy Laboratory (NREL). Interconnections Seam Study. October 2020. https://www.nrel.gov/analysis/seams.html

[7] Lawrence Berkeley National Laboratory (LBNL). "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection." April 2022. https://emp.lbl.gov/queues

community, and industry stakeholders to support these outcomes and others of equal or greater public benefit to build the grid that America needs.

Additionally, as the need for grid investment that can enhance reliability and resilience grows, historical trends show that investments by major U.S. electric utilities—representing about 70% of total U.S. electric load—into the distribution system has been more than double that into the transmission system.[8,9] DOE is looking to leverage funding to unlock transformative projects that would not be built and deployed without the federal funding under the GRIP program across the transmission system, distribution system, and combination system approaches – including catalyzing and unlocking increased investment into the transmission system to support greater overall grid resilience and reliability at the greatest scale. With the funding provided by the BIL across these three programs there is an opportunity to not only invest in power system infrastructure that addresses critical national, interregional, and regional needs, but also a unique chance to build partnerships between states, local governments, Tribes, and power system operators that align industry objectives with broader regional, interregional, and national goals to enhance reliability, all-hazards resilience, and efficiency of the electric grid. A comprehensive approach that considers all the opportunities available within the BIL can result in more coordinated efforts across relevant stakeholders that can ultimately guide investment strategies for improving resilience beyond what the BIL can support directly.

Concurrently, infrastructure investments in power system resilience offer the opportunity to include a diverse set of populations, including underserved and disadvantaged communities, in the development of resilience strategies that focus on communities, and equitable access to opportunities and the benefits that derive from them. DOE believes there are significant benefits to be realized by coordinating the implementation of the three BIL programs focused on power sector infrastructure, grid reliability and resilience.

As part of the whole-of-government approach to advance equity and encourage worker organizing and collective bargaining[10,11,12] and in alignment with BIL sections 40101(c), 40107, and 40103(b), this FOA and any related activities will seek to encourage meaningful engagement and participation of labor unions and

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[8] Energy Information Administration (EIA). "Utilities continue to increase spending on transmission infrastructure." February 9, 2018. https://www.eia.gov/todayinenergy/detail.php?id=34892
[9] EIA. "Major utilities continue to increase spending on U.S. electric distribution systems." July 20, 2018. https://www.eia.gov/todayinenergy/detail.php?id=36675
[10] EO 13985, "Advancing Racial Equity and Support for Underserved Communities Through the Federal Government" (Jan. 20, 2021).
[11] EO 14025, "Worker Organizing and Empowerment," April 26, 2021.
[12] EO 14052, "Implementation of the Infrastructure Investment and Jobs Act," November 18, 2021.

underserved communities and underrepresented groups, including consultation with Tribal Nations[13,14]. Consistent with Executive Order 14008, this FOA is designed to help meet the goal that 40% of the overall benefits of certain federal investments flow to disadvantaged communities and drive the creation of accessible good-paying jobs with the free and fair chance for workers to join a union.

ii. Strategic Goals

This FOA seeks applications to address these three goals:

1. Transform community, regional, interregional, and national resilience, including in consideration of future shifts in generation and load
2. Catalyze and leverage private sector and non-federal public capital for impactful technology and infrastructure deployment
3. Advance community benefits

1. <u>Transform community, regional, interregional, and national resilience, including in consideration of future shifts in generation and load</u>

As explained in DOE's Building a Better Grid Initiative Notice of Intent, modernizing, hardening, and expanding the grid will enhance the resilience of our entire electric system, and ensure that electricity is available to customers when it is needed most.[15] Projects funded by the GRIP program should be designed to enable significant national, regional, or community resilience improvements, consistent with grid needs that will manifest as a result of aging grid infrastructure, increasing climate change-related or other hazards to reliability, and the clean energy transition. An important objective of community and regional resilience and transformation is improving the electric grid's ability to avoid, mitigate and recover from major disruptions and plan for future disruptions across all hazards. Grid investments can enhance resilience by, among other things:

i. increasing regional and interregional electricity transfer capacity,
ii. addressing the most consequential system needs and challenges that cause or contribute to the problematic and increasing interconnection queue time for clean energy,

[13] EO 13175, November 6, 2000 "Consultation and Coordination With Indian Tribal Governments", charges all executive departments and agencies with engaging in regular, meaningful, and robust consultation with Tribal officials in the development of Federal policies that have Tribal implications.
[14] Presidential Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships. January 26, 2021. https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/26/memorandum-on-tribal-consultation-and-strengthening-nation-to-nation-relationships/
[15] Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization. 87 FR 2769

iii. facilitating clean energy deployment, generation mix diversity, and other system benefits.

A systemic approach can consider all aspects of physical infrastructure and the ability of power system owners and operators to mitigate outages and restore power to communities as well as the ability of communities to work towards recovery. Therefore, alignment with state, regional, and national energy planning is important to understand threats, mitigation approaches, and system needs, and to help with the prioritization of funding. BIL investments can leverage these plans as well as industry and other investments to assist in community transformation. Applications may consider emphasis on a specific threat, such as wildfire or flooding, and how an approach can transform a region or community resulting in a significant resilience and other economic benefits, with an emphasis on equity.

2. Catalyze and leveraging private sector and non-federal public capital for impactful technology and infrastructure deployment

Investments should prioritize driving innovative approaches to achieving grid infrastructure deployment at-scale where significant economic benefits to mitigate threats and impacts of disruptive events to communities can be attained.

DOE is looking for applications that will leverage private sector and non-federal public capital to advance deployment goals. These efforts will be aligned with state, regional, or other planning activities and goals. As state resilience plans continue to be updated annually and evaluate future risks, DOE is interested in how Federal funds will leverage industry investments towards hardening their system and/or advancing innovative solutions to enhance system resilience.

DOE is also interested in leveraging Federal infrastructure funding to maximize grid infrastructure deployment at-scale. Successful projects will demonstrate how federal investments under the GRIP program can lead to additional future investments by industry, communities, venture capital, and other private debt and equity capital. Investments should prioritize grid improvements especially in cases where GRIP investments can overcome institutional barriers, perceived risk, and the like so as to both deliver beneficial grid outcomes and demonstrate an approach suitable for replication.

3. Advance Community Benefits

Increasing grid reliability and resilience provides notable benefits such as reducing outages resulting from extreme events and/or other causes, by reducing restoration times from such outages, or by reducing risks to health and safety for the affected community.

In keeping with the Administration's goals, and as an agency whose mission includes strengthening our country's energy prosperity, DOE seeks projects that should not only contribute to the country's energy technology and climate goals, but also meet the following four priority goals (1) support meaningful community and labor engagement; (2) invest in the American workforce; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the goal that 40% of the overall benefits of certain federal investments flow to disadvantaged communities (the Justice40 Initiative).

iii. Community Benefits Plan: Job Quality and Equity

To support the goal of building a clean and equitable energy economy, the BIL-funded projects are expected to (1) support meaningful community and labor engagement; (2) invest in America's workforce; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the President's goal that 40% of the overall benefits of certain federal investments flow to disadvantaged communities (the Justice40 Initiative). To ensure these goals are met, applications must include a Community Benefits Plan that describes how the proposed project would incorporate the four objectives stated above.

Applicants are encouraged to submit Community and Labor Partnership Documentation from established labor and community-based organizations that demonstrate the applicant's ability to achieve the above goals as outlined in the Community Benefits Plan. Within the Community Benefits Plan, the applicant is encouraged to provide specific detail on how to ensure the delivery of measurable community and jobs benefits, ideally through the use of negotiated agreements between the applicant and the community, and/or the applicant and labor unions referred to collectively here as "Workforce and Community Agreements." These include good neighbor agreements, community benefits agreements, community workforce agreements, project labor agreements, and other collective bargaining agreements. See Section IV.D.xv for the Community Benefits Plan content requirements.

a. Community and Labor Engagement

The project planning should include engagement with an inclusive collection of local labor unions, governments Tribal entities, and other stakeholders -- such as, residents and businesses, entities that carry out workforce development programs, and community-based organizations that support or work with disadvantaged communities. Considering the importance of the four priorities listed above and the financial investment in the projects to be funded under this FOA, stakeholder engagement is a relatively small cost that delivers high value.

Proactive and meaningful engagement with stakeholders ensures stakeholders' perspectives can be incorporated into the project plan, allows for transparency, and helps reduce or eliminate certain risks associated with the project.

b. Quality Jobs

In keeping with the Administration's goals, and to ensure the agency's energy projects contribute to overall economic prosperity, the DOE strongly supports investments that expand accessible good-paying jobs, with assurances that workers will have a free and fair chance to join a union; promote worker power for marginalized workers and in hard-to-organize and changing industries; improve job quality through the adoption of strong labor standards; support responsible employers; and foster safe, healthy, and inclusive workplaces and communities free from harassment and discrimination, and support strategies that develop a skilled and inclusive local workforce to build and maintain the country's energy infrastructure and grow domestic manufacturing.

c. Diversity, Equity, Inclusion, and Accessibility

Advancing equity, civil rights, racial justice, and equal opportunity is a key priority of the Biden Administration. The term "equity" means the consistent and systematic fair, just, and impartial treatment of all individuals, including individuals who belong to underserved communities that have been denied such treatment, such as Black, Latino, and Indigenous and Native American persons, Asian Americans and Pacific Islanders and other persons of color; members of religious minorities; lesbian, gay, bisexual, transgender, and queer (LGBTQ+) persons; persons with disabilities; persons who live in rural areas; and persons otherwise adversely affected by persistent poverty or inequality.[16]

As part of a whole of government approach to advancing equity, this FOA seeks to encourage the participation of underserved communities[17] and underrepresented groups, ensure equitable access to business opportunities, good-paying jobs, career-track training, and other economic opportunities. Partnerships with community-based organizations, comprehensive support services to reduce barriers to access to opportunities and ensuring business and employment opportunities for members of DACs are key tools. Applicants are

[16] Executive Order 13985, "Advancing Racial Equity and Support for Underserved Communities Through the Federal Government" (Jan. 20, 2021).

[17] The term "underserved communities" refers to populations sharing a particular characteristic, as well as geographic communities, that have been systematically denied a full opportunity to participate in aspects of economic, social, and civic life, as exemplified by the list of in the definition of "equity." E.O. 13985. For purposes of this FOA, communities identified as disadvantaged or underserved communities by their respective States; communities identified on the Index of Deep Disadvantage referenced at https://news.umich.edu/new-index-ranks-americas-100-most-disadvantaged-communities/, and communities that otherwise meet the definition of "underserved communities" stated above.

required to describe how diversity, equity, inclusion, and accessibility objectives will be incorporated in the project.

Further, Applicants are highly encouraged to include individuals from groups historically underrepresented[18,19] in science, technology, engineering and math (STEM) fields on their project teams.

Minority Serving Institutions[20], Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, Veteran Owned Businesses, Tribal Colleges and Universities, or entities located in an underserved community that meet the eligibility requirements (See Section III) are encouraged to apply as the prime applicant or participate on an application as a proposed partner to the prime applicant. The Selection Official may consider the inclusion of these types of entities as part of the selection decision (See Section V.C.i. Program Policy Factors).

d. Justice40 Initiative

In addition to the Federal government's initiative to achieve greater participation from underserved communities and underrepresented groups, this FOA supports DOE's commitment to the Justice40 Initiative.[21] Benefits include (but are not

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[18] According to the National Science Foundation's 2019 report titled, "Women, Minorities and Persons with Disabilities in Science and Engineering", women, persons with disabilities, and underrepresented minority groups—blacks or African Americans, Hispanics or Latinos, and American Indians or Alaska Natives—are vastly underrepresented in the STEM (science, technology, engineering and math) fields that drive the energy sector. That is, their representation in STEM education and STEM employment is smaller than their representation in the U.S. population. https://ncses.nsf.gov/pubs/nsf19304/digest/about-this-report For example, in the U.S., Hispanics, African Americans and American Indians or Alaska Natives make up 24 percent of the overall workforce, yet only account for 9 percent of the country's science and engineering workforce. DOE seeks to inspire underrepresented Americans to pursue careers in energy and support their advancement into leadership positions. https://www.energy.gov/articles/introducing-minorities-energy-initiative

[19] See also. Note that Congress recognized in Section 305 of the American Innovation and Competitiveness Act of 2017, Public Law 114-329:

> (1) [I]t is critical to our Nation's economic leadership and global competitiveness that the United States educate, train, and retain more scientists, engineers, and computer scientists; (2) there is currently a disconnect between the availability of and growing demand for STEM-skilled workers; (3) historically, underrepresented populations are the largest untapped STEM talent pools in the United States; and (4) given the shifting demographic landscape, the United States should encourage full participation of individuals from underrepresented populations in STEM fields.

[20] Minority Serving Institutions refers to universities and colleges that serve a significant percentage of students from minority groups, including Historically Black Colleges and Universities/Other Minority Institutions as educational entities recognized by the Office of Civil Rights (OCR), U.S. Department of Education, and identified on the OCR's Department of Education U.S. accredited postsecondary minorities' institution list. See https://www2.ed.gov/about/offices/list/ocr/edlite-minorityinst.html.

21 The Justice40 initiative, created by E.O. 14008, establishes a goal that 40% of the overall benefits of certain federal investments flow to disadvantaged communities. The Justice40 Interim Guidance provides a broad

limited to) measurable direct or indirect investments or positive project outcomes that achieve or contribute to the following in DACs: (1) a decrease in energy burden; (2) a decrease in environmental exposure and burdens; (3) an increase in access to low-cost capital; (4) an increase in high-quality job creation, the clean energy job pipeline, and job training for individuals; (5) increases in clean energy enterprise creation and contracting (e.g., minority-owned or disadvantaged business enterprises); (6) increases in energy democracy, including community ownership; (7) increased parity in clean energy technology access and adoption; and (8) an increase in energy resilience.

B. Topic Areas

i. Topic Areas

The proposed objectives, eligibility, and the technical approach for each of the three programs within the GRIP program are outlined below. DOE will be requesting and reviewing concept papers as part of the application process. Based on DOE's review of the concept papers, DOE will encourage a subset of applicants to submit Full Applications.

- Topic Area 1: Grid Resilience Grants (BIL section 40101(c))
- Topic Area 2: Smart Grid Grants (BIL section 40107[22])
- Topic Area 3: Grid Innovation Program (BIL section 40103(b))

<u>Topic Area 1: Grid Resilience Grants *(40101(c))*</u>

Objectives:

This program supports activities that reduce the likelihood and consequence of impacts to the electric grid due to extreme weather, wildfire, and natural disaster. The statutory language requires prioritization of projects that will generate the greatest regional or community benefit (whether rural or urban) in reducing the likelihood and consequences of disruptive events.[23]

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definition of disadvantaged communities (Page 2): https://www.whitehouse.gov/wp-content/uploads/2021/07/M-21-28.pdf. The DOE, Office of Management and Budget, and/or the Federal Council on Environmental Quality (CEQ) may issue additional and subsequent guidance regarding the designation of disadvantaged communities and recognized benefits under the Justice40 Initiative. DOE will also recognize disadvantaged communities as defined and identified by the White House Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST), which can be located at https://screeningtool.geoplatform.gov/

[22] Topic Area 2 is authorized under section 1306 of the Energy Independence and Security Act of 2007, which was later amended by section 40107 of the BIL. The authority is codified at 42 USC §17386.

[23] 42 USC §18711(c)(4)

DOE is seeking projects that address comprehensive transformational transmission and distribution technology solutions that will mitigate one or multiple hazards across a region or within a community, including but not limited to wildfires, floods, hurricanes, extreme heat, extreme cold, storms, and any other event that can cause a disruption to the power system.

Consistent with the broader overall objectives of the GRIP programs, projects in this area should demonstrate that they will provide significant economic and justice benefits to communities, can leverage capital investment, and lead to repeatable solutions for other entities.

Technical approaches of interest include (but are not limited to) the following:

Grants under this program are for projects and activities that increase the ability of applicants to reduce the likelihood and consequences of impacts to the electric grid due to extreme weather, wildfire, natural disaster and other disruptive events.

Applicants will demonstrate a transformational, comprehensive approach to mitigating one or more hazards across a region or within a community. Concurrently, DOE encourages applicants to align proposed grid resilience and grid hardening investments with broader State, Tribal, or regional resilience or energy security plans.

DOE is particularly interested in applications for adaptive storage deployment, microgrid deployment, and the undergrounding of existing distribution and transmission lines – in addition to other eligible projects and solutions that provide significant benefit. In the selection process, DOE will prioritize applications that address community transformation or the ability to leverage capital investments.

For Topic Area 1, there are a broad range of activities, technologies, equipment, and hardening measures to reduce the likelihood and consequences of disruptive events that are eligible for funding[24], which include:

(A) weatherization technologies and equipment;
(B) fire-resistant technologies and fire prevention systems;
(C) monitoring and control technologies;
(D) the undergrounding of electrical equipment;
(E) utility pole management;
(F) the relocation of power lines or the reconductoring of power lines with low-sag, advanced conductors;

[24] See BIL section 40101(e)(1)(A)-(L), as codified at 42 USC 18711(e)(1)(A)-(L).

(G) vegetation and fuel-load management;
(H) the use or construction of distributed energy resources for enhancing system adaptive capacity during disruptive events, including—
   a. microgrids; and
   b. battery-storage subcomponents;
(I) adaptive protection technologies;
(J) advanced modeling technologies;
(K) hardening of power lines, facilities, substations, of other systems;
(L) the replacement of old overhead conductors and underground cables; and
(M) new distribution lines below 69 kV, reconductoring, undergrounding and other upgrades to existing transmission infrastructure.

The following activities are NOT eligible[25] for funding under Topic Area 1: *construction of a new— (I) electric generating facility; or (II) large-scale battery-storage facility that is not used for enhancing system adaptive capacity during disruptive events; (III) transmission lines at or above 69 kV; nor cybersecurity.*

Topic Area 1 Requirements

- Small utility set-aside. Thirty percent (30%) of the total funding available for Topic Area 1 will be set aside for small utilities, which are defined as entities that sell no more than 4,000,000 MWh of electricity per year.[26] Entities applying for this set aside must demonstrate their eligibility by submitting their total retail electricity sales to ultimate customers as reported to the Energy Information Administration (EIA) on Form 861 for the last reporting year.

  In addition to submission of the Form 861, applications to Topic Area 1 must include a Project Description and Assurances Document (PDAD) certifying the applicant is a Small Utility (sells no more than 4,000,000 MWh of electricity per year). The PDAD template is provided as Appendix F.

- Report on Resilience Investments. An applicant must submit as part of their application, a report detailing past, current, and future efforts by the eligible entity to reduce the likelihood and consequences of disruptive events.[27] The report must summarize any program and related approved funding that the applicant's organization has implemented over the past 3 years to reduce the likelihood of events in which operations of the electric grid are disrupted, preventively shut off, or cannot operate safely due to extreme weather, wildfire, or a natural disaster. The report must also summarize current and

[25] See BIL section 40101(e)(2), as codified at 42 USC 18711(e)(2).
[26] 42 USC §18711(c)(5)
[27] 42 USC §18711(c)(2)(B)

future efforts planned over at least the next 3 years to reduce the likelihood and consequences of disruptive events.

In addition to submission of the report, applications to Topic Area 1 must include a PDAD that confirms the total amount (USD) of qualifying resilience investments that have been spent for the previous 3 years and the time period utilized for calculation of the reported amount by completing and certifying the PDAD. The PDAD template is provided as Appendix F.

- <u>Funding supplemental to existing efforts</u>. Grants under this program are in general intended to be supplemental to existing hardening efforts of applicants for any given year.[28] The applicant should describe in a narrative how the grant funding provided by this program would result in proposed activities that are additional to efforts that would have been undertaken but-for the funding and will generate the greatest community or regional resilience benefit in reducing the likelihood and consequences of disruptive events. This may include the acceleration or expansion of planned activities that would not be accelerated or expanded but-for the funding. The narrative should reference the *Report on Resilience Investments* to demonstrate how the proposed activities would be additional to existing planned investments.

- <u>Biennial Report to Congress</u>. Every two years DOE will submit a report to Congress covering data on the cost of projects, the types of activities funded, and the extent to which the ability of the power grid to withstand disruptive events has increased.[29] Awardees will be required to track and report this data to DOE.

- <u>Section 40101(d), ALRD 2736</u>. Per BIL section 40101(e)(2) (C) APPLICATION LIMITATIONS.—*An eligible entity may not submit an application for a grant provided by the Secretary under subsection (c) and a grant provided by a State or Indian Tribe pursuant to subsection (d) during the same application cycle*. If the applicant is a subaward/subcontract recipient for an application submitted under IIJA Section 40101(d), ALRD 2736, the applicant must describe the differences between the GRIP FOA 2740 application [40101(c)] and the ALRD 2736 [40101(d)] application in the PDAD. The PDAD template is provided as Appendix F.

Topic Area 1 Teaming Arrangements

Eligible applicants include electric grid operators; electricity generators; electricity storage operators; transmission owners or operators; distribution

[28] 42 USC §18711(c)(1)(A)
[29] 42 USC §18711(i)

providers; and fuel suppliers.[30] Applicants must certify that the prime applicant is an eligible entity type as listed above via completion and submission of the PDAD. The PDAD template is provided as Appendix F.

As appropriate, ensuring that the state, Indian Tribe or territory is engaged in the approach is important. The expectation of the Department is that regulatory stakeholders will be engaged in this process to ensure cost recovery of the concepts are achieved.

<u>Topic Area 2: Smart Grid Grants *(40107)*</u>

Objectives

Topic Area 2 seeks to deploy and catalyze technology solutions that increase the flexibility, efficiency, reliability, and resilience of the electric power system, with particular focus on enhancing the system's capabilities to meet the following objectives:

- increase the capacity of transmission facilities or the capability of the transmission system to reliably transfer increased amounts of electric energy;
- prevent faults that may lead to wildfires or other system disturbances;
- integrate variable renewable energy resources at the transmission and distribution levels; and,
- facilitate the aggregation and integration (edge-computing) of electric vehicles and other grid-edge devices or electrified loads.

According to a 2018 DOE report, the sum of real-time congestion cost for 2016 among major system operators— specifically, the California Independent System Operator (CAISO), the Electricity Reliability Council of Texas (ERCOT), Independent System Operator New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and PJM — was $4.8 billion.[31] Another study from DOE found that grid-enhancing technologies (GETs) have significant potential to modernize the grid to increase capacity to reduce clean energy curtailment, unlock additional clean energy generation, and enable more resilient grid operation.[32] Complimentary modeling of the impact of deploying three specific types of GETs – Advanced Power Flow Control, Dynamic Line Ratings and Topology Optimization – at a national scale could deliver $5 billion in yearly energy production cost savings, with upfront investment paid back in just 6 months, and double the amount of renewables that can be integrated into the electricity grid prior to building new

[30] 42 USC §18711(a)(2)
[31] U.S. Department of Energy. "Annual U.S. transmission data review." 2018.
[32] U.S. Department of Energy. "Grid-Enhancing Technologies: A Case Study on Ratepayer Impact." February 2022.

large-scale transmission lines. A more granular assessment conducted under the same study looked at the Southwest Power Pool system and found that deploying the same three types of GETs could enable 2 adjoining states, to integrate 5,200 MW of wind and solar generation currently in interconnection queues by 2025 without any new large-scale transmission buildout, more than double the development possible without the technologies.[33] DOE is interested in applications that deploy GETs to modernize the grid and unlock significant public benefit, and therefore demonstrate the suggested benefit shown by various studies. DOE is also interested in other eligible types of applications that deploy scalable solutions that deliver significant public benefit.

Applicants are encouraged to coordinate with and support broader State, local, Tribal, and regional strategies on resilience, energy security, energy & environmental justice, and decarbonization. In addition, smart grid technologies funded and deployed at-scale under this program should have a pathway to wider market adoption such that the funding significantly encourages and facilitates the development of a smart grid.[34] Aggregation of smart grid technologies is encouraged to accelerate deployment.

Technical approaches of interest include (but are not limited to) the following:

A broad set of eligible smart grid investments and capabilities is allowed under statute,[35] and any combination of smart grid investments and functions that support the objectives are eligible. DOE will require that projects support data standards (e.g., Green Button Connect[36]), interoperability, and non-discriminatory data access on a real-time basis.

Priority investments in Topic Area 2 include the following:

- Increasing transmission capacity and operational transfer capacity through grid enhancing technologies such as dynamic line rating, flow control devices, advanced conductors, and network topology optimization, to improve system efficiency and reliability.

- Improving the visibility of the electrical system to grid operators, to help quickly rebalance the electrical system with autonomous controls, through data analytics, software, and sensors.

[33] The Brattle Group. "Unlocking the Queue with Grid-Enhancing Technologies." February 1, 2021.
[34] 42 USC §17386(e)(1)(C)
[35] 42 USC §17386(b) and (d)
[36] Green Button Connect is the energy industry standard enabling easy access to, and secure sharing of, utility-customer energy-usage data.

- Enhance secure communication and data flow between distribution components, through investments in optical ground wire, dark fiber, operational fiber, and wireless broadband communications networks.

- Aggregation and integration of distributed energy resources and other "grid-edge" devices to provide system benefits, such as renewable energy resources, electric vehicle charging infrastructure, vehicle-to-grid technologies and capabilities, and smart building technologies.

- Enhancing interoperability and data architecture of systems that support two-way flow of both electric power and localized analytics to provide information between electricity system operators and consumers.

- Anticipate and mitigate the impacts of extreme weather or natural disaster on grid resiliency, including investments to increase the ability to redirect or shut of power to minimize blackouts, prevent wildfires, and avoid further damage.

Complete list of qualifying investments under Topic Area 2[37] includes:

1. In the case of appliances covered for purposes of establishing energy conservation standards under part B of title III of the Energy Policy and Conservation Act of 1975,[38] the documented expenditures incurred by a manufacturer of such appliances associated with purchasing or designing, creating the ability to manufacture, and manufacturing and installing for one calendar year, internal devices that allow the appliance to engage in Smart Grid functions.

2. In the case of specialized electricity-using equipment, including motors and drivers, installed in industrial or commercial applications, the documented expenditures incurred by its owner or its manufacturer of installing devices or modifying that equipment to engage in Smart Grid functions.

3. In the case of transmission and distribution equipment fitted with monitoring and communications devices to enable smart grid functions, the documented expenditures incurred by the electric utility to purchase and install such monitoring and communications devices.

4. In the case of metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system or retail distributor or marketer of electricity that are capable of engaging in Smart

[37] 42 USC §17386(b)
[38] 42 USC §6291

Grid functions, the documented expenditures incurred by the electric utility, distributor, or marketer and its customers to purchase and install such devices.

5. In the case of software that enables devices or computers to engage in Smart Grid functions, the documented purchase costs of the software.

6. In the case of entities that operate or coordinate operations of regional electric grids, the documented expenditures for purchasing and installing such equipment that allows Smart Grid functions to operate and be combined or coordinated among multiple electric utilities and between that region and other regions.

7. In the case of persons or entities other than electric utilities owning and operating a distributed electricity generator, the documented expenditures of enabling that generator to be monitored, controlled, or otherwise integrated into grid operations and electricity flows on the grid utilizing Smart Grid functions.

8. In the case of electric or hybrid-electric vehicles, the documented expenses for devices that allow the vehicle to engage in Smart Grid functions (but not the costs of electricity storage for the vehicle).

9. In the case of data analytics that enable software to engage in Smart Grid functions, the documented purchase costs of the data analytics.

10. In the case of buildings, the documented expenses for devices and software, including for installation, that allow buildings to engage in demand flexibility or Smart Grid functions.

11. In the case of utility communications, the documented expenditures incurred by the electric utility to purchase and install operational fiber and wireless broadband communications networks to enable data flow between distribution system components.

12. In the case of advanced transmission technologies such as dynamic line rating, flow control devices, advanced conductors, network topology optimization, or other hardware, software, and associated protocols applied to existing transmission facilities that increase the operational transfer capacity of a transmission network, the documented expenditures to purchase and install those advanced transmission technologies.

13. In the case of extreme weather or natural disasters, the documented expenses for monitoring, control devices and other equipment that enable

the ability to redirect or shut off power to minimize blackouts and avoid further damage.

The following expenditures and investments are not eligible for Smart Grid grant funding under Topic Area 2[39]:

1. Investments or expenditures for Smart Grid technologies, devices, or equipment that utilize specific tax credits or deductions under the Internal Revenue Code, as amended.

2. Expenditures for electricity generation, transmission, or distribution infrastructure or equipment not directly related to enabling Smart Grid functions.

3. After the final date for State consideration of the Smart Grid Information Standard under section 2621(d)(17) of title 16, an investment that is not in compliance with such standard.

4. After the development and publication by the Institute[22] of protocols and model standards for interoperability of smart grid devices and technologies, an investment that fails to incorporate any of such protocols or model standards.

5. Expenditures for physical interconnection of generators or other devices to the grid except those that are directly related to enabling Smart Grid functions.

6. Expenditures for ongoing salaries, benefits, or personnel costs not incurred in the initial installation, training, or startup of smart grid functions.

7. Expenditures for travel, lodging, meals or other personal costs.

8. Ongoing or routine operation, billing, customer relations, security, and maintenance expenditures.

Teaming Arrangements

DOE encourages applicant teams to include a broad set of stakeholders, including but not limited to, electric grid operator or owners, technology vendors, system integrators, subject matter experts, local energy and environmental justice organizations, and community leaders. In addition, State,

[39] 42 USC §17386(c)

Tribal, territory, or regulatory stakeholders should be engaged in the approach as appropriate.

Topic Area 3: Grid Innovation Program *(40103(b))*

DOE is interested in both technical and non-technical approaches that improve grid reliability and resilience on a local, regional, and interregional scale. Innovative approaches can include advanced technologies, innovative partnerships, financial arrangements, deployment of projects identified by innovative planning and cost allocation approaches, and environmental siting and permitting strategies. Applications may address the transmission system, the distribution system, or both, and may include elements such as: distributed generation assets; load point flexibility enhancements; energy storage systems and other flexibility enhancements; technologies to increase the capacity of the transmission and distribution system; grid-edge technologies; sensing, communications, and control technologies and approaches; grid-forming power electronics; integrated system designs; projects with innovative financing and permitting solutions; projects with uncommon or innovative regulatory structures, projects that are a product of innovative planning, modeling, or cost-allocation approaches, and other similar projects.

There is currently insufficient development of projects that are critical to reliability and resilience of the grid, particularly in projects that would achieve the following outcomes for the transmission system: 1) increasing transfer capacity between regions, 2) addressing the most consequential system needs and challenges that cause or contribute to long and increasing interconnection queue time for clean energy, and 3) increasing supply of a geographically and technologically diverse sets of location-constrained energy resources to enhance resource adequacy and reduce correlated generation outages. DOE is particularly interested in applications that demonstrate innovative models, methods, technologies, or other ways to achieve these outcomes that enable grid resilience and reliability. DOE is also interested in all other eligible grid projects that support similar or greater public resilience and reliability benefit.

Applications combining multiple approaches are encouraged, and all applications should demonstrate how the proposed new, innovative approaches interact with each other and any existing infrastructure to increase overall system resiliency. Hardening of assets and infrastructure may be included but must show a clear contribution to overall system resiliency. Project results should enable asset owners and operators to effectively articulate within local, state, and Federal decision-making frameworks the economic, technical, and societal benefits of new innovative approaches that improve system reliability and resilience. Applications that invest in America's workforce; advance energy and environmental justice and support the goals of the Justice40 Initiative; engage in meaningful community and stakeholder engagement; and advance diversity, equity, inclusion and accessibility are of particular importance in this topic area.

Entities who are eligible to apply to Topic Area 3 include States, local governments, Tribes, and public utility commissions. Applicants must certify that the prime applicant is an eligible entity via completion and submission of the PDAD. The PDAD template is provided as Appendix F.

Objectives

This program seeks to provide financial assistance to eligible entities (States, local governments, Tribes, public utility commissions) to facilitate coordination, and collaboration with electric sector owners and operators to:

- demonstrate innovative approaches to transmission, storage, and distribution infrastructure to harden and enhance resilience and reliability; and
- demonstrate new approaches to enhance regional grid resilience, implemented through States by public and rural electric cooperative entities on a cost-shared basis.[40]

DOE is soliciting projects that contribute significantly to one or more of the following primary objectives:

- Ensuring reliable grid operations by reducing the frequency, scale, and/or duration of disruptions, reducing capacity interconnection time, increasing regional and interregional transfer capacity, or reducing costs associated with increased reliability.
- Improving overall grid resilience in terms of avoiding, withstanding, responding to, and recovering from disruptions, including deliberate attacks, accidents, the growing threats of extreme weather events and climate change, and other naturally occurring threats or incidents. Projects may demonstrate:
    - Individual technologies and solutions (or multiple technologies and solutions working as a system) that address resilience in one part of the power system (e.g., transmission system).
    - Technologies and solutions that address resilience across the traditional boundaries in the power system (e.g., between transmission and distribution).
- Enhancing collaboration between and among eligible entities and private and public sector owners and operators on grid resilience, including in alignment with regional resilience strategies and plans. This includes collaboration across state and other territorial boundaries such as grid operators or other balancing authorities, with a particular focus on innovating planning processes,

[40] 42 USC 18712: Electric grid reliability and resilience research, development, and demonstration (house.gov)

modeling, cost allocation, permitting, reduction of interconnection queue waiting time, inter-regional projects and other activities aided by collaborative approaches.

- Contributing to the decarbonization of the electricity and broader energy system in a way that supports system resilience, reliability, and affordability by improving access to technologically and geographically diverse energy resources, including distributed energy resources and electrification opportunities.
- Providing enhanced system value, improving current and future system cost-effectiveness, and delivering economic benefits to community members, underrepresented regions, or other stakeholders. Applications should clearly identify their value proposition for each individual stakeholder group.

Project results should enable asset owners and operators to effectively articulate within local, state, regional and federal decision-making frameworks the economic, technical, and societal benefits of deploying new innovative technologies that improve system reliability and resilience.

Technical Approaches of interest include (but are not limited to) the following:

Applications to this topic area may address the transmission system, the distribution system, storage, or a combination.

Applications combining multiple approaches are encouraged, and all applications should demonstrate how proposed innovative approaches interact with each other and any existing infrastructure to increase overall system resilience. Innovative approaches can include advanced technologies; innovative partnerships; new financial arrangements; deployment of projects identified by innovative planning, modeling, or cost allocation approaches; and/or innovative environmental siting, permitting strategies, or community engagement practices. Hardening of assets and infrastructure may be included but must show a clear contribution to overall system resilience.

DOE has identified the three areas of interest for this program spanning the transmission system, distribution system, and combination system approaches. These are not exhaustive, nor intended to be fully independent. Applications that address more than one area of interest, or that present alternative approaches to accomplish the key objectives outside of the specified areas of interest, are encouraged.

Area of Interest 1: Transmission system applications

The transmission system in operation today is the backbone of the electricity delivery system that connects all grid resources and acts as the path for electricity to flow from generation to demand. Transmission capacity constraints and congestion can prevent delivery of clean, cost-effective electricity to consumers, harming overall system reliability. Advanced transmission technologies, coupled with advanced computational and advanced dynamic situational awareness, are a suite of tools that can help address transmission challenges, improve the efficiency and effectiveness of electricity delivery, and increase the reliability and resilience of the system. Innovative project approaches, including those leveraging advanced transmission technologies can reduce or remove the existing technical, economic, and/or regulatory barrier(s) necessary to accelerate widescale transmission expansion and renewable energy interconnection. Proposed solutions should demonstrate enhanced transmission system operational flexibility or capacity while enhancing reliability.

Applications in this area could include technologies, solutions, and advanced functionalities such as:

- Investments and strategies that accelerate interconnection of clean energy generation and/or storage;
- Interregional or cross-ISO/RTO projects that address key grid reliability, flexibility, and/or resilience challenges;
- Projects addressing grid access challenges for remote, stranded, or novel low-carbon resources;
- Planning, modeling, cost allocation, or other approaches that enable a transition to innovative financial and/or regulatory constructs that accelerate transmission expansion;
- Underground or underwater HVDC systems in challenging environments;
- Capacity enhancing approaches such as advanced conductors or dynamic line rating systems;
- Congestion management techniques including energy storage and integrated controls;
- Transmission-scale reactive power devices;
- Flexible alternating current transmission system (FACTS) devices;
- Solid state transformers;
- Power flow controllers for AC or High Voltage Direct Current (HVDC) systems.

Area of Interest 2: Distribution system applications

The distribution system serves as a highly interconnected system providing reliable electricity to consumers. The integration of variable distributed energy sources such wind and solar power, new loads such as electric vehicle charging, and energy storage into these networks is creating new challenges and opportunities for power system control and operation. Solutions should demonstrate improved cost-value characteristics relative to alternative approaches, managing distribution grid integration costs and traditional asset upgrade costs while maintaining or enhancing system reliability and service provision.

In addition, extreme weather events have led to an increase in the frequency and duration of de-energization events. These occurrences, along with other experienced or potential disruptions of the distribution grid highlight the importance of improved system resilience. Solutions should demonstrate improved system resilience in response to disruptions and/or recovery from these events with an emphasis on community transformation.

Applications in this area could include demonstration of technologies, solutions, and advanced functionalities such as:

- Adaptive microgrid formation, reliable islanded operations, and service provision during grid-tied operations;
- Demonstration of reliable and resilient system operations utilizing high levels of distributed renewable generation and energy storage, or increased levels of non-emitting, non-electric distributed energy resources (e.g., renewable heating or cooling);
- Black-start capable systems and control approaches to minimize negative impacts during power grid disruptions;
- Provision of grid services from distributed, advanced grid-forming inverter-based systems at sufficient scale and system complexity;
- Behind the meter asset operations, aggregation, and coordination to provide demand response and grid services, including building systems, distributed generation, energy storage, electric vehicle fleets and others.

<u>Area of Interest 3: Combination systems applications</u>
While there is a clear differentiation between transmission and distribution systems in the current electrical grid, they both function within the same overall systems. Area of Interest 3 is intended to highlight opportunities to improve joint resilience and functionality across both grid sectors. This could involve using assets in one sector to provide services to the other in a manner that reduces upgrade or expansion requirements, or efforts to improve visibility and communication across sectors to allow for more complete optimization of grid operations.

Applications in this area could include demonstration of technologies, solutions, and advanced functionalities such as:

- Utilization of distribution grid assets to provide backup power and reduce transmission requirements;

- Utilization of distribution grid dispatchable loads, distributed generation, and energy storage to manage transmission congestion and limit required upgrades;
- Optimized integrated management of transmission and distribution systems;
- Monitoring and control technologies, that can provide improved resilience and extend grid visibility & situational awareness across the entire electric delivery system by providing real-time situational awareness across the system.

Requirements

Topic Area 3 will prioritize large scale and complex system projects that demonstrate innovative approaches while offering the greatest public benefit with a clear path to replication, scale, and ability to impact decarbonization objectives; projects that provide equitable access to innovative technologies and business models; and demonstrations that involve multiple communities and diverse asset compositions including electrical, thermal, building and transportation solutions.

Successful applications in this Topic Area 3 will clearly explain:

- The scale of the proposed project and the differentiated value that this scale will bring to the project and the subject area.

- The replicability, extensibility, and scalability of the method, model, financing, planning, regulatory approach, technology, or other solution given the system in which it will be demonstrated.

- Estimated costs and value propositions for the proposed project including contribution to system cost effectiveness, as well as a relative value comparison to alternative approaches.

- How quantitative, measurable metrics relating to the intended improvements in grid outcomes will be utilized to evaluate success.

- The readiness, viability, and expected timing of the deployment strategy, including key milestones relating to critical financial, development, and implementation stages of the project.

- The project management strategy, including use of project funds to secure subrecipient or vendor expertise to support prime recipients on project management, accounting, environmental justice community engagement, federal reporting, and technical oversight.

- Note: this approach has been identified as a potential path forward to address resource limitations at recipient organizations. It is not required that external expertise and groups be included, but use of project funds to support these functions will be allowed in accordance with applicable federal cost principles (Section I.i Allowable Costs)

- How federal funding to address the risks identified in the application will increase the likelihood of securing additional public and/or private investment.

- How the project will invest in America's workforce, meaningfully engage communities and stakeholders, advance energy and environmental justice, and ensure diversity, equity, inclusion, and accessibility.

Teaming Arrangements
This topic area seeks to support demonstrations at sufficient scale and within a system of sufficient complexity to establish confidence in the value proposition of the proposed approach. Applicants are encouraged to assemble diverse and multi-functional project teams capable of receiving and managing federal and matching funds, executing on technology deployments and upgrades, conducting operational testing and validation, analyzing resultant data and performance, and clearly communicating and disseminating findings to key stakeholders and decision makers. The team must designate one team member to serve as the prime recipient and that team member must qualify as an eligible applicant. See Section III.

In addition, all teams should clearly articulate their ***strategy to enable wide-scale adoption*** of their proposed solutions following a successful demonstration and their ***intended commitment*** to utilize these or resultant solutions within their own systems and jurisdictions. Projects selected under this topic area will attempt to resolve technical and commercial adoption barriers by increasing stakeholder confidence in the performance, cost, and value characteristics of their proposed system. In order to ensure maximum impact following these demonstrations, a clear plan to disseminate findings, replicate successes, incorporate the outcomes of the demonstrations into investment decision-making frameworks, and activate additional public and private capital is crucial. These plans should consider which stakeholders and decision makers must be informed as to the demonstration results, what types and quality of information would lead to concrete investment decisions, and how to integrate with local, Tribal, state, and regional energy strategies and transition plans to amplify overall impact and rate of adoption. Initial strategies should be presented in the application, but it is expected that these plans will be developed more fully over the course of the project.

All work for projects selected under this FOA must be performed in the United States. See Section IV.I.iii. and Appendix B.

Project Management Plan: Successful applicants under all topic areas will be required to prepare a Project Management Plan (PMP). The initial PMP is due 30 days after award. The PMP shall be revised and resubmitted as often as necessary, during the course of the project, to capture any major/significant changes to the planned approach, budget, key personnel, major resources, etc. A sample PMP is available at: BIL-GRIP Application Forms and Templates | netl.doe.gov.

ii. Teaming Partner List

DOE is compiling a "Teaming Partner List" to facilitate the formation of new project teams for this FOA. The Teaming Partner List allows organizations who may wish to participate on an application to express their interest to other applicants and to explore potential partnerships.

Updates to the Teaming Partner List will be available in the FedConnect (https://www.fedconnect.net/) website and on the Grid Resilience and Innovation Partnerships (GRIP) Program web page: Grid Resilience Innovation Partnership Programs | Department of Energy. The Teaming Partner List will be regularly updated to reflect new teaming partners who provide their organization's information. Applicants must register with FedConnect to have access to the Teaming Partner List (and any updates to it) in FedConnect.

SUBMISSION INSTRUCTIONS: Any organization that would like to be included on this list should submit the following information: Organization Name, Contact Name, Contact Address, Contact Email, Contact Phone, Organization Type, Area of Technical Expertise, Brief Description of Capabilities, and Topic Area(s) of Interest. Interested parties should complete the Excel file titled DOE-FOA-0002740 Teaming Partner List provided as an attachment to this announcement and email it to GDOFOA@hq.doe.gov with the subject line "Teaming Partner Information."

DISCLAIMER: By submitting a request to be included on the Teaming Partner List, the requesting organization consents to the publication of the above-referenced information. By facilitating the Teaming Partner List, DOE is not endorsing, sponsoring, or otherwise evaluating the qualifications of the individuals and organizations that are self-identifying themselves for placement on this Teaming Partner List. DOE will not pay for the provision of any information, nor will it compensate any applicants or requesting organizations for the development of such information.

C. Applications Specifically Not of Interest

The following types of applications will be deemed nonresponsive and will not be reviewed or considered (See Section III.D. of the FOA):

- Applications that fall outside the technical parameters specified in Sections I.A. and I.B. of the FOA.
- Applications for proposed technologies that are not based on sound scientific principles (e.g., violates the laws of thermodynamics).
- Topic Area 1: Applications that propose the construction of a new—(I) electric generating facility; or (II) large-scale battery-storage facility that is not used for enhancing system adaptive capacity during disruptive events; (III) transmission lines at or above 69 kV; nor cybersecurity.
- Topic Area 2: See full list of investments not included in section I.B.

D. Authorizing Statutes

The programmatic authorizing statute is as follows:

- Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL):
  - Section 40101(c) – 42 USC §18711(c);
  - Section 40107 – 42 USC §17386;
  - Section 40103(b) – 42 USC §18712(b).
- Public Law (PL) 95-91, DOE Organization Act;
- PL 109-58, Energy Policy Act 2005;
- PL 110-140 Energy Independence and Security Act of 2007.

Awards made under this announcement will fall under the purview of 2 Code of Federal Regulation (CFR) Part 200 as amended by 2 CFR Part 910.

E. Notice of Bipartisan Infrastructure Law-Specific Requirements

Be advised that special terms and conditions apply to projects funded by the BIL relating to:

- Reporting, tracking and segregation of incurred costs;
- Reporting on job creation and preservation;
- Publication of information on the Internet;
- Access to records by Inspectors General and the Government Accountability Office;

- Requiring all of the iron, steel, manufactured goods, and construction materials used in the infrastructure activities of applicable projects are produced in the United States;
- Ensuring laborers and mechanics employed by contractors or subcontractors on BIL-funded projects are paid wages equivalent to prevailing wages on similar projects in the area;
- Protecting whistleblowers and requiring prompt referral of evidence of a false claim to an appropriate inspector general; and
- Certification and Registration.

Recipients of funding appropriated by the BIL must comply with requirements of all applicable Federal, State, and local laws, regulations, DOE policy and guidance, and instructions in this FOA. Recipients must flow down the requirements to subrecipients to ensure the recipient's compliance with the requirements.

II. Award Information

A. Award Overview

i. Estimated Funding

Under BIL sections 40101(c), 40107, and 40103(b), the BIL appropriated approximately $10.5 billion for the five-year period encompassing FY22 through FY26, via annual release of competitive FOAs. This FOA will include both fiscal years 2022 and 2023, totaling approximately $3.9 Billion of federal funding that DOE expects to make available for new awards under this FOA, subject to the availability of appropriated funds. DOE anticipates making approximately 40-100 awards under this FOA. DOE may issue one, multiple, or no awards. Individual award amounts vary by topic area, see details below.

Please note, the second competitive funding opportunity is expected to be issued in the first quarter of Fiscal Year 2024 and will include approximately $2 Billion in federal funding for FY 2024, subject to the availability of appropriated funds, along with any unspent funds from the current FY22-23 funding cycle.

DOE may issue awards in one, multiple, or none of the following topic areas:

Topic Area Number	Topic Area Title	Anticipated Number of Awards	Anticipated Minimum Award Size for Any One Individual	Anticipated Maximum Award Size for Any One Individual	Approximate Total Federal Funding	Anticipated Period of Performance (months)

			Award (Fed Share)	Award (Fed Share)	Available for All Awards	
1	Grid Resilience Grants (40101(c))	10*	N/A	Either the total of the applicant's last three years of resilience investments or $100 million, whichever is lower**	$918 Million	60 months
2	Smart Grid Grants (40107)	25-40	N/A	$50 Million	$1,080 Million	60 months
3	Grid Innovation Program (40103(b))	4-40	N/A	$250 Million (Increased award size of $1 Billion per award for interregional transmission projects only)	$1,820 Million	60-96 months

*Approximately 3 of the anticipated number of awards will be made to small utilities. Thirty percent (30%) of the total funding available will be set aside for small utilities, which are defined as entities that sell no more than 4,000,000 MWh of electricity per year.[41]

**DOE may not award a grant to an eligible entity in an amount that is greater than "the total amount that the eligible entity has spent in the previous 3 years on efforts to reduce the likelihood and consequences of disruptive events". [42] DOE is including an additional discretionary limit of $100 million in federal funds per award. DOE will interpret "efforts to reduce the likelihood and consequences of disruptive events" as those activities, technologies, equipment, and hardening measures that are eligible for grants under this provision.[43]

DOE may establish more than one budget period for each award and fund only the initial budget period(s). Funding for all budget periods, including the initial budget period, is not guaranteed.

[41] 42 USC §18711(c)(5)
[42] 42 USC §18711(c)(3)
[43] 42 USC §18711(e)1

ii. Period of Performance

DOE anticipates making awards that will run from 60 months to 96 months in length (see table below), comprised of one or more budget periods. Project continuation will be contingent upon several elements, including satisfactory performance and DOE's Go/No-Go decision. For a complete list and more information on the Go/No-Go review, see Section VI.B.xv.

Topic Area	Period of Performance
1	60 months
2	60 months
3	60 - 96 months

iii. New Applications Only

DOE will accept only new applications under this FOA. DOE will not consider applications for renewals of existing DOE-funded awards through this FOA.

B. DOE Funding Agreements

Through cooperative agreements and other similar agreements, DOE provides financial and other support to projects that have the potential to realize the FOA objectives. DOE does not use such agreements to acquire property or services for the direct benefit or use of the United States government.

i. Cooperative Agreements (applies to Topic Area 3 ONLY)

DOE anticipates funding projects selected under Topic Area 3 through cooperative agreements. In the event funding is awarded to another federal agency, the funding may be provided directly to the agency through an interagency agreement.

Through cooperative agreements, DOE provides financial or other support to accomplish a public purpose of support or stimulation authorized by federal statute. Under cooperative agreements, the government and prime recipients share responsibility for the direction of projects.

DOE has substantial involvement in all projects funded via cooperative agreement. See Section VI.B.x of the FOA for more information on what substantial involvement may involve.

ii. Grants (applies to Topic Area 1 and 2 ONLY)

DOE anticipates funding projects selected under Topic Areas 1 and 2 through grants. In the event funding is awarded to another federal agency, the funding may be provided directly to the agency through an interagency agreement.

III. Eligibility Information

To be considered for substantive evaluation, an applicant's submission must meet the criteria set forth below. If the application does not meet these eligibility requirements, it will be considered ineligible and removed from further evaluation.

A. Eligible Applicants

i. Topic Area 1 (Section 40101(c))

The following domestic entities are eligible to apply:

- electric grid operator;
- electricity storage operator;
- electricity generator;
- transmission owner or operator;
- distribution provider; and
- fuel supplier.

ii. Topic Area 2 (Section 40107)

The following domestic entities are eligible to apply:

- Institutions of higher education;
- For-profit entities;
- Non-profit entities; and
- State and local governmental entities, and tribal nations.

iii. Topic Area 3 (40103(b))

The following domestic entities are eligible to apply:

- a State;
- a combination of 2 or more States;
- an Indian Tribe;
- a unit of local government; and
- a public utility commission.

iv. General Requirements for Eligible Applicants For Topic Areas 1, 2, and 3

a. Domestic Entities

Under this FOA, to qualify as a domestic entity, an entity other than a State or Indian Tribe must be organized, chartered or incorporated (or otherwise formed) under the laws of the United States or of a particular state or territory of the United States and have a physical place of business in the United States. Both recipients and subrecipients must be domestic entities absent an approved waiver.

b. Foreign Entities

In limited circumstances, DOE may approve a waiver to allow a foreign entity to participate as a prime recipient or subrecipient. A foreign entity may submit a Full Application to this FOA, but the Full Application must be accompanied by an explicit written waiver request. Likewise, if the applicant seeks to include a foreign entity as a subrecipient, the applicant must submit a separate explicit written waiver request in the Full Application for each proposed foreign subrecipient.

Appendix B lists the information that must be included in a foreign entity waiver request. The applicant does not have the right to appeal DOE's decision concerning a waiver request.

c. National Laboratories/FFRDCs

National Laboratories and Federal Funded Research and Development Centers (FFRDCs) are not eligible to apply for funding as a prime recipient and may not be proposed as a subrecipient on another entity's application. This restriction is applicable to both DOE/NNSA and non-DOE/NNSA National Laboratories and FFRDCs.

The National Energy Technology Laboratory (NETL) is not eligible for award under this announcement and may not be proposed as a subrecipient on another entity's application. An application that includes NETL as a prime recipient or subrecipient will be considered non-responsive.

d. Federal agencies

Federal agencies, instrumentalities, and corporations (other than DOE) are eligible to participate as a subrecipient if the agency, instrumentality, or corporation satisfies the statutory requirements, but are not eligible to apply as a prime recipient; except for the Tennessee Valley Authority (under Topic Area 1), who is eligible to participate as a prime recipient and as a subrecipient.

e. Teaming Arrangements

The project team must designate one team member to serve as the prime recipient and that team member must qualify as an eligible entity. If the project team will operate as an incorporated or unincorporated consortium, DOE may request the applicant to provide additional information, such as any collaboration agreement, that describes management structure and the rights and responsibilities of each consortium member.

f. Additional Restrictions

Entities banned from doing business with the U.S. government such as entities debarred, suspended, or otherwise excluded from or ineligible for participating in Federal programs are not eligible.

Nonprofit organizations described in section 501(c)(4) of the Internal Revenue Code of 1986 that engaged in lobbying activities after December 31, 1995 are not eligible to apply for funding. Nonprofit organizations described in section 501(c)5 of the Internal Revenue Code are eligible to apply for funding.

v. Restricted Eligibility (applies to Topic Area 1 and Topic Area 3 ONLY)

In accordance with 2 CFR 910.126, DOE restricted eligibility for Topic Area 1 and Topic Area 3 to incorporate the eligibility requirements set forth in sections 40101(c) and 40103(b) of the BIL, as codified at 42 USC 18711 and 42 USC 18712(c), respectively.

B. Cost Sharing

Applicants are bound by the cost share proposed in their Full Applications if selected for award negotiations.

Topic Area	Topic Area Title	Cost Match/Share Requirement
1	Section 40101(c) – "Grants to Eligible Entities on Preventing Outages and Enhancing the Resilience of the Electric Grid (Grid Resilience Grants)"	An eligible entity that receives a grant under this section shall be required to match 100% of the amount of the grant (at least 50% of the Federal funds only, rather than the Total Project Cost). Exception for small utilities: An eligible entity that sells not more than 4,000,000 megawatt hours of electricity per year shall be required to match 1/3 of the grant.*
2	Section 40107 – "Deployment of Technologies to Enhance Grid Flexibility (Smart Grid Grants)"	The cost share must be at least 50% of the total project costs. The cost share must come from non-federal sources unless otherwise allowed by law.
3	Section 40103 (b) – "Program Upgrading Our Electric Grid and Ensuring Reliability and	Section 988 of the Energy Policy Act of 2005 (42 U.S.C. 16352) shall apply. The cost share must be at least 50% of the total project costs.[44,45] The

[44] Total project costs is the sum of the government share, , and the recipient share of project costs.
[45] Energy Policy Act of 2005, Pub.L. 109-58, sec. 988. Also see 2 CFR 200.306 and 2 CFR 910.130 for additional cost sharing requirements.

	Resiliency (Grid Innovation Program)"	cost share must come from non-federal sources unless otherwise allowed by law.

***Cost matching**: "Cost matching" for the non-federal share is calculated as a percentage of the Federal funds only, rather than the Total Project Cost.

To assist applicants in calculating proper cost match/share amounts, DOE has included a cost share information sheet and sample cost share calculation as Appendix A to this FOA.

i. Legal Responsibility

Although the cost share requirement applies to the project as a whole, including work performed by members of the project team other than the prime recipient, the prime recipient is legally responsible for paying the entire cost share. If the funding agreement is terminated prior to the end of the project period, the prime recipient is required to contribute at least the cost share percentage of total expenditures incurred through the date of termination.

The prime recipient is solely responsible for managing cost share contributions by the project team and enforcing cost share obligation assumed by project team members in subawards or related agreements.

ii. Cost Share Allocation

Each project team is free to determine how best to allocate the cost share requirement among the team members. The amount contributed by individual project team members may vary, as long as the cost share requirement for the project as a whole is met.

iii. Cost Share Types and Allowability

Every cost share contribution must be allowable under the applicable federal cost principles, as described in Section IV.I.i. of the FOA. In addition, cost share must be verifiable upon submission of the Full Application.

Project teams may provide cost share in the form of cash or in-kind contributions. Cost share may be provided by the prime recipient, subrecipients, or third parties (entities that do not have a role in performing the scope of work). Vendors/contractors may not provide cost share. Any partial donation of goods or services is considered a discount and is not allowable.

Cash contributions include, but are not limited to: personnel costs, fringe costs, supply and equipment costs, indirect costs and other direct costs.

In-kind contributions are those where a value of the contribution can be readily determined, verified and justified but where no actual cash is transacted in securing the good or service comprising the contribution. Allowable in-kind contributions include, but are not limited to: the donation of volunteer time or the donation of space or use of equipment.

Project teams may use funding or property received from state or local governments to meet the cost share requirement, so long as the funding was not provided to the state or local government by the Federal government.

The prime recipient may not use the following sources to meet its cost share obligations including, but not limited to:

- Revenues or royalties from the prospective operation of an activity beyond the project period;
- Proceeds from the prospective sale of an asset of an activity;
- Federal funding or property (e.g., federal grants, equipment owned by the federal government); or
- Expenditures that were reimbursed under a separate federal program.

Project teams may not use the same cash or in-kind contributions to meet cost share requirements for more than one project or program.

Cost share contributions must be specified in the project budget, verifiable from the prime recipient's records, and necessary and reasonable for proper and efficient accomplishment of the project. As all sources of cost share are considered part of total project cost, the cost share dollars will be scrutinized under the same federal regulations as federal dollars to the project. Every cost share contribution must be reviewed and approved in advance by the Contracting Officer and incorporated into the project budget before the expenditures are incurred.

Applicants are encouraged to refer to 2 CFR 200.306 and 2 CFR 910.130 for additional cost sharing requirements.

iv. Cost Share Verification

Applicants are required to provide written assurance of their proposed cost share contributions in their Full Applications.

Upon selection for award negotiations, applicants are required to provide additional information and documentation regarding their cost share contributions. Please refer to Appendix A of the FOA.

v. Cost Share Payment

DOE requires prime recipients to contribute the cost share amount incrementally over the life of the award. Specifically, the prime recipient's cost share for each billing period must always reflect the overall cost share ratio negotiated by the parties (i.e., the total amount of cost sharing on each invoice when considered cumulatively with previous invoices must reflect, at a minimum, the cost sharing percentage negotiated).

In limited circumstances, and where it is in the government's interest, the DOE Contracting Officer may approve a request by the prime recipient to meet its cost share requirements on a less frequent basis, such as monthly or quarterly. Regardless of the interval requested, the prime recipient must be up-to-date on cost share at each interval. Such requests must be sent to the Contracting Officer during award negotiations and include the following information: (1) a detailed justification for the request; (2) a proposed schedule of payments, including amounts and dates; (3) a written commitment to meet that schedule; and (4) such evidence as necessary to demonstrate that the prime recipient has complied with its cost share obligations to date. The Contracting Officer must approve all such requests before they go into effect.

C. Compliance Criteria

Concept Papers and Full Applications must meet all compliance criteria listed below or they will be considered noncompliant. DOE will not review or consider noncompliant submissions, including Concept Papers and Full Applications that were: submitted through means other than specifically stated in the FOA; submitted after the applicable deadline; and/or submitted incomplete. DOE will not extend the submission deadline for applicants that fail to submit required information by the applicable deadline due to server/connection congestion.

i. Concept Papers

Concept Papers are deemed compliant if:

- The Concept Paper complies with the content and form requirements in Section IV.C. of the FOA; and
- The applicant successfully emailed all required documents to FOA2740@netl.doe.gov by the deadline stated in this FOA.

ii. Full Applications

Full Applications are deemed compliant if:

- The Full Application complies with the content and form requirements in Section IV.D. of the FOA; and

- The applicant successfully uploaded all required documents and clicked the "Submit" button in Grants.gov by the deadline stated in the FOA.

D. Responsiveness Criteria

All "Applications Specifically Not of Interest," as described in Section I.C. of the FOA, are deemed nonresponsive and are not reviewed or considered.

E. Other Eligibility Requirements (Reserved)

F. Limitation on Number of Concept Papers and Full Applications Eligible for Review

An entity may submit more than one Concept Paper and Full Application to this FOA, provided that each application describes a unique, scientifically distinct project and provided that an eligible Concept Paper was submitted for each Full Application.

G. Questions Regarding Eligibility

DOE will not make eligibility determinations for potential applicants prior to the date on which applications to this FOA must be submitted. The decision whether to submit an application in response to this FOA lies solely with the applicant.

IV. Application and Submission Information

A. Application Process

The application process will include two phases: a Concept Paper phase and a Full Application phase. **Only applicants who have submitted an eligible Concept Paper will be eligible to submit a Full Application**.

At each phase, DOE performs an initial eligibility review of the applicant submissions to determine whether they meet the eligibility requirements of Section III of the FOA. DOE will not review or consider submissions that do not meet the eligibility requirements of Section III. All submissions must conform to the following form and content requirements, including maximum page lengths (described below). Concept papers must be emailed to FOA2740@netl.doe.gov, and full applications must be submitted via Grants.gov at https://www.grants.gov/. **DOE will not review or consider submissions submitted through means other than specifically stated in the FOA, submissions submitted after the applicable deadline, or incomplete**

submissions. DOE will not extend deadlines for applicants who fail to submit required information and documents due to server/connection congestion.

The Concept Paper and Full Application must conform to the following requirements:

- Each must be submitted in Adobe PDF format unless stated otherwise;
- Each must be written in English;
- All pages must be formatted to fit on 8.5 x 11-inch paper with margins not less than one inch on every side. Use Calibri typeface, a black font color, and a font size of 12 point or larger (except in figures or tables, which may be 10-point font). A symbol font may be used to insert Greek letters or special characters, but the font size requirement still applies. References must be included as footnotes or endnotes in a font size of 10 or larger. Footnotes and endnotes are counted toward the maximum page requirement; and
- Each submission must not exceed the specified maximum page limit, including cover page, charts, graphs, maps, and photographs when printed using the formatting requirements set forth above and single spaced. If applicants exceed the maximum page lengths indicated below, DOE will review only the authorized number of pages and disregard any additional pages.

Applicants are responsible for meeting each submission deadline. **Applicants are strongly encouraged to submit their Concept Papers and Full Applications at least 48 hours in advance of the submission deadline**. Under normal conditions (i.e., at least 48 hours in advance of the submission deadline), applicants should allow at least 1 hour to submit a Concept Paper and Full Application. Once the Concept Paper and Full Application is submitted as specifically stated in the FOA, applicants may revise or update that submission until the expiration of the applicable deadline. If changes are made to any of these documents, the applicant must resubmit the Concept Paper and Full Application before the applicable deadline.

DOE urges applicants to carefully review their Concept Paper and Full Application to allow sufficient time for the submission of required information and documents. Full Applications that pass the initial eligibility review will undergo comprehensive technical merit review according to the criteria identified in Section V of the FOA.

B. Application Forms

The application forms and instructions are available on Grants.gov at https://www.grants.gov/.

Note: The maximum file size that can be uploaded to the Grants.gov website is 10MB. Files in excess of 10MB cannot be uploaded, and hence cannot be submitted for review. If a file exceeds 10MB but is still within the maximum page limit specified in the FOA, it must be broken into parts and denoted to that effect. For example:

TechnicalVolume_Part_1
TechnicalVolume_Part_2

DOE will not accept late submissions that resulted from technical difficulties due to uploading files that exceed 10MB.

C. Content and Form of the Concept Paper

Each Concept Paper must be limited to a single Topic Area. Do not consolidate multiple Topic Areas into a single Concept Paper.

The Concept Paper must conform to the following content and form requirements and must not exceed the stated page limits. If applicants exceed the maximum page lengths indicated below, DOE will review only the authorized number of pages and disregard any additional pages.

Applicants are encouraged to include the following information in the subject line of the email that includes the concept paper submission: Applicant Name – Topic Area X (insert topic area number to which you are applying for the X) – Concept Paper.

Section	Page Limit*	Description
Cover Page	1 page maximum	The cover page should include the project title, the specific announcement Topic Area being addressed, entity type of the applicant organization (e.g., electric grid operator, State, etc.), both the technical and business points of contact, names of all team member organizations, the project location(s), and any statements regarding confidentiality.
Project and/or Technology Description	12 pages maximum	Applicants are required to describe succinctly: • How the project addresses the topic area's eligible uses and technical approaches. • How the project supports State, local, Tribal, community and regional resilience, in reducing the likelihood and consequences of disruptive events, decarbonization, or other energy strategies and plans. • The grid-benefitting outcomes to be delivered by the project.

		• The impact of the project to reduce innovative technology risk; achieve further deployment at-scale; and lead to additional private sector investments. • The impact that DOE funding would have on the proposed project. • The readiness, viability, and expected timing of the project.
Community Benefits Plan	5 Pages maximum	Applicants are required to describe succinctly the approach to be taken with the Community Benefits Plan, addressing the four core elements: • community and labor engagement leading to negotiated agreements; • investing in job quality and workforce continuity; • advancing diversity, equity, inclusion, and accessibility; and • contributing to the Justice40 Initiative goal that 40% of the overall benefits of certain climate and clean energy investments flow to disadvantaged communities.
Addendum A	5 pages maximum	Applicants are required to describe succinctly the qualifications, experience, and capabilities of the proposed Project Team, including: • Whether the Project Manager and Project Team have the skill and expertise needed to successfully execute the project plan; • Whether the applicant has prior experience that demonstrates an ability to perform tasks of similar risk and complexity; • Whether the applicant has worked together with its teaming partners on prior projects or programs; and • Whether the applicant has adequate access to equipment and facilities necessary to accomplish the effort and/or clearly explain how it intends to obtain access to the necessary equipment and facilities. • Applicants may provide graphs, charts, or other data to supplement their Project and/or Technology Description.
Addendum B Topic Area 1 ONLY, if applicable**	N/A	Applicants who are small utilities applying to Topic Area 1 must submit the EIA Form 861 for the last reporting year showing the total retail electricity sales to ultimate customers to ensure status as a small utility.
*Applicants are encouraged to include page numbers in the footer of every page.		
**Small utilities ONLY: 30% of the total funding available will be set aside for small utilities, which are defined as entities that sell no more than 4,000,000 MWh of electricity per year.[46]		

[46] 42 USC §18711(c)(5)

DOE makes an independent assessment of each Concept Paper based on the criteria in Section V of the FOA. DOE will encourage a subset of applicants to submit Full Applications. Other applicants will be discouraged from submitting a Full Application. An applicant who receives a "discouraged" notification may still submit a Full Application. DOE will review all eligible Full Applications. However, by discouraging the submission of a Full Application, DOE intends to convey its lack of programmatic interest in the proposed project in an effort to save the applicant the time and expense of preparing an application that is unlikely to be selected for award negotiations.

DOE may include general comments provided from reviewers on an applicant's Concept Paper in the encourage/discourage notification sent via email at the close of that phase.

D. Content and Form of the Full Application

Applicants must submit a Full Application by the specified due date and time to be considered for funding under this FOA. Applicants must complete the following application forms found on the Grants.gov website at https://www.grants.gov/ in accordance with the instructions.

Applicants should reference the date and time stated on the FOA cover page to plan for the number of days from receipt of the Concept Paper Encourage/Discourage notification to preparing and submitting a Full Application. Regardless of the date the applicant receives the Encourage/Discourage notification, the submission deadline for the Full Application remains the date and time stated on the FOA cover page.

i. Full Application Content Requirements

Each Full Application must be limited to a single concept or technology. Do not consolidate unrelated concepts and technologies in a single Full Application. Full Applications must conform to the following content and form requirements and must not exceed the stated page limits. If applicants exceed the maximum page lengths indicated below, DOE will review only the authorized number of pages and disregard any additional pages.

Component	File Format	Page Limit	File Name
SF-424	Form	N/A	N/A
Project/Performance Site Location(s)	Form	N/A	N/A
Technical Volume	PDF	25	TechnicalVolume.pdf

Resumes	PDF	2 pages each	Resumes.pdf
Letters of Commitment	PDF	1 page each	LOC.pdf
Community Partnership Documentation	PDF	1 page each	LeadOrganization_Partner.pdf
Statement of Project Objectives	MS Word	5	SOPO.doc or docx
Budget Justification Workbook	MS Excel	N/A	Budget_Justification.xls or xlsx
Summary/Abstract for Public Release	PDF	1	Summary.pdf
Summary Slide	MS PowerPoint	Up to 3	Slide.ppt or pptx
Subrecipient Budget Justification	MS Excel	N/A	Subrecipient_Budget_Justification.xls or xlsx
Environmental Questionnaire	PDF	N/A	Env.pdf
SF-LLL Disclosure of Lobbying Activities	Form	N/A	N/A
Foreign Entity Waiver Requests and Foreign Work Waiver Requests	PDF	N/A	FN_Waiver.pdf
Buy America Requirements for Infrastructure Projects Waiver Requests	PDF	N/A	BAWaiver.pdf
Community Benefits Plan: Job Quality and Equity	PDF	12	CBenefits.pdf
Potentially Duplicative Funding Notice (if applicable)	PDF	N/A	PDFN.pdf
Report on Resilience Investments Topic Area 1 ONLY	PDF	10	ResilienceInvestments.pdf
EIA 861 Topic Area 1 ONLY, if applicable*	PDF	N/A	EIA861.pdf
Locations of Work	MS Excel	N/A	LOW.xls or xlsx
Project Description and Assurances Document (PDAD)	PDF	N/A	PDAD.pdf
*Small utilities ONLY: 30% of the total funding available will be set aside for small utilities, which are defined as entities that sell no more than 4,000,000 MWh of electricity per year.[47]			

DOE provides detailed guidance on the content and form of each component below.

ii. SF-424: Application for Federal Assistance

Complete the SF 424 form first to populate data in other forms. Complete all required fields in accordance with the instructions on the form. The list of certifications and assurances in Field 21 can be found at https://www.energy.gov/management/financial-assistance-forms-and-

[47] 42 USC §18711(c)(5)

information-applicants-and-recipients, under Certifications and Assurances. Note: The dates and dollar amounts on the SF-424 are for the complete project period of performance and not just the first project year, first phase or other subset of the project period of performance.

iii. Project/Performance Site Location(s)

Indicate the primary site where the work will be performed. If a portion of the project will be performed at any other site(s), identify the site location(s) in the blocks provided.

Note that the Project/Performance Site Congressional District is entered in the format of the 2-digit state code followed by a dash and a 3-digit Congressional district code, for example VA-001. Hover over this field for additional instructions.

Use the Next Site button to expand the form to add additional Project/Performance Site Locations.

iv. Technical Volume

The Technical Volume must be submitted in PDF format. The Technical Volume must conform to the following content and form requirements, including maximum page lengths. This volume must address the technical review criteria as discussed in Section V of the FOA. Save the Technical Volume in a single PDF file using the following convention for the title “TechnicalVolume.pdf” and click on "Add Mandatory Other Attachment" to attach. Note: If a file exceeds 10 MB but is still within the maximum page limit specified in the FOA, it must be broken into parts and denoted to that effect. For example:

TechnicalVolume_Part_1
TechnicalVolume_Part_2

Applicants must provide sufficient citations and references to the primary research literature to justify the claims and approaches made in the Technical Volume. However, DOE and reviewers are under no obligation to review cited sources.

The Technical Volume to the Full Application may not be more than 25 pages, including the cover page, table of contents, and all citations, charts, graphs, maps, photos, or other graphics, and must include all of the information in the table below. The applicant should consider the weighting of each of the technical review criterion (see Section V of the FOA) when preparing the Technical Volume.

The Technical Volume should clearly describe and expand upon information provided in the Concept Paper. The Technical Volume must conform to the following content requirements:

Technical Volume Content Requirements	
SECTION/PAGE LIMIT	**DESCRIPTION**
Cover Page	The cover page should include the project title, the specific FOA Topic Area being addressed, both the technical and business points of contact, names of all team member organizations, names of the senior/key personnel and their organizations, the project location(s), and any statements regarding confidentiality.
Project Overview (Approximately 10% of the Technical Volume)	The Project Overview should contain the following information: • Background: The applicant should discuss the background of their organization, including the history, successes, and current project development status (i.e., the development baseline) relevant to the technical topic being addressed in the Full Application. • Project Goal: The applicant should explicitly identify the targeted improvements to the baseline infrastructure, practices and regulatory framework, and/or technology and the critical success factors in achieving that goal, including the ways in which the proposed project location and related infrastructure, skilled workforce, community benefits, etc. will contribute to the success of the overall project. • DOE Impact: The applicant should discuss the impact that DOE funding would have on the proposed project. Applicants should specifically explain how DOE funding, relative to prior, current, or anticipated funding from other public and private sources, is necessary to enable the project to progress, and to achieve its intended objectives. • Community Benefits Plan: Job Quality and Equity – The applicant should summarize the overall anticipated benefits that will accrue to the local community and DACs (including, but not limited to, decreased duration, frequency, or impact of power disruption; increased access to clean power; and the support of minority business enterprises). The applicant should summarize a plan to attract, train, and retain a skilled labor force with strong labor standards, ensure workers' free and fair chance to join a union, and identify potential partners they are working with to support these objectives. • The applicant should articulate a strategy for sharing and maximizing the project's benefits across disadvantaged communities and include a discussion of how resident and community leadership will be engaged throughout the project's duration. DOE encourages efforts to reach historically underserved populations, racial minorities, and women. These strategies should create the connectivity and conditions for growth where they may not exist, such as in rural, underserved, and disadvantaged communities.

	• Identify any potential long-term constraints the project will have on the community's access to natural resources (e.g., water) and Tribal cultural resources. If applicable, describe a long-term cleanup strategy that ensures communities and neighborhoods remain healthy and safe and not burdened with cleanup costs and waste. • The applicant should outline a climate resilience strategy that accounts for climate impacts and extreme weather patterns such as high winds (tornadoes and hurricanes), heat and freezing temperatures, drought, wildfire, and floods.
Technical Description, Innovation, and Impact (Approximately 30% of the Technical Volume)	The Technical Description should contain the following information: • Relevance and Outcomes: The applicant should provide a detailed description of the project, including grid outcomes, the technology used, and other principles and objectives that will be pursued during the project. This section should describe the relevance of the proposed project to the goals and objectives of the FOA, including the potential for the deployment of the project to meet specific desired grid outcomes and other relevant performance targets. The applicant should clearly specify the expected outcomes of the project. • Feasibility: The applicant should demonstrate the technical feasibility of the proposed technology and capability of achieving the anticipated performance targets, including a description of previous work done and prior results. This section should also address the project's access to necessary infrastructure (e.g., transportation, water, electric transmission), including any use of existing infrastructure, as well as to a skilled workforce. • Innovation and Impacts: The applicant should describe the current standard practice and/or state-of-the-art technology in the applicable field, the specific innovation (which can include advanced technologies; innovative partnerships; new financial arrangements; deployment of projects identified by innovative planning, modeling, or cost allocation approaches; and/or innovative environmental siting, permitting strategies, or community engagement practices) of the proposed technology, the advantages of proposed technology over current and emerging technologies, and the overall impact on advancing the state-of-the-art/technical baseline if the project is successful. • The applicant should describe how the project supports State, local, Tribal, regional and national resilience, decarbonization, or other energy goals, strategies and plans. • The applicant should address the potential impact of the project to reduce perceived risk for project deployment; achieve further deployment at-scale to; and lead to additional private sector investments. • <u>**Topic Area 1 (Grid Resilience Grants) applications must:**</u> o Address how the proposed project will generate the greatest community, regional, or interregional resilience benefit in reducing the likelihood and consequences of disruptive events.

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Address how the project (1) comprehensively mitigates one or more hazards faced by community or region; (2) comprehensively mitigates the potential for equipment to cause a wildfire in a community or region; (3) fully addresses the consequences of an outage caused by a natural hazard; or (4) mitigates economic risk as derived from outage duration or outage frequency.
Address how the grant funding provided by this program would result in proposed activities that go beyond and are additional to efforts that would have been undertaken but-for the funding and will generate the greatest community or regional resilience benefit in reducing the likelihood and consequences of disruptive events. The narrative should reference the Report on Resilience Investments to demonstrate how the proposed activities would be additional to existing planned investments.

<u>Topic Area 2 (Smart Grid Grants) applications must:</u>

Describe how the project will have a significant effect in encouraging and facilitating the development of smart grid functions identified as priority focus areas in 1.B.Topic Area 2
Describe how the project would enhance the system flexibility to meet program objectives.

<u>Topic Area 3 (Grid Innovation Program) applications must:</u>

Describe how the project will address innovative approaches and deployment goals across transmission systems, distribution, or both as identified as priority focus areas in 1.B.Topic Area 3.
Describe how federal funding to address the risks identified in the application will increase the likelihood of securing additional public and/or private investment or otherwise enable the project to proceed.
Include how the concept will provide economic benefit to communities or regions that mitigate impacts from extreme events and disruptions.
Describe how the project has the potential to deliver near-term impact, with appropriate quantitative metrics
Describe project’s readiness, viability, and expected timing.

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<td>Workplan
(Approximately 40% of the Technical Volume)</td>
<td>The Workplan should include a summary of the Project Objectives, Technical Scope, Work Breakdown Structure (WBS), Milestones, Go/No-Go Decision Points, and Project Schedule. A detailed SOPO is separately requested. The Workplan should contain the following information:

Project Objectives: The applicant should provide a clear and concise (high-level) statement of the goals and objectives of the project as well as the expected outcomes.

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	• Technical Scope Summary: The applicant should provide a summary description of the overall work scope and approach to achieve the objective(s). The overall work scope is to be divided by performance periods that are separated by discrete, approximately annual decision points (see below for more information on Go/No-Go decision points). The applicant should describe the specific expected end result of each performance period, including milestones detailed in the Community Benefits Plan. • WBS and Task Description Summary: The Workplan should describe the work to be accomplished and how the applicant will achieve the milestones, will accomplish the final project goal(s), and will produce all deliverables. The Workplan is to be structured with a hierarchy of performance period (approximately annual), task and subtasks, which is typical of a standard WBS for any project. The Workplan shall contain a concise description of the specific activities to be conducted over the life of the project. The description shall be a full explanation and disclosure of the project being proposed (i.e., a statement such as "we will then complete a proprietary process" is unacceptable). It is the applicant's responsibility to prepare an adequately detailed task plan to describe the proposed project and the plan for addressing the objectives of this FOA. The summary provided should be consistent with the SOPO. The SOPO will contain a more detailed description of the WBS and tasks. • Milestone Summary: The applicant should provide a summary of appropriate milestones throughout the project to demonstrate success. A milestone may be either a progress measure (which can be activity based) or a SMART technical milestone. SMART milestones should be Specific, Measurable, Achievable, Relevant, and Timely, and must demonstrate a technical achievement rather than simply completing a task. Unless otherwise specified in the FOA, the minimum requirement is that each project must have at least one milestone per quarter for the duration of the project with at least one SMART technical milestone per year (depending on the project, more milestones may be necessary to comprehensively demonstrate progress). The applicant should also provide the means by which the milestone will be verified. • Go/No-Go Decision Points (See Section VI.B.xv for more information on the Go/No-Go Review): provide a summary of project-wide Go/No-Go decision points at appropriate points in the Workplan. At a minimum, each project must have at least one project-wide Go/No-Go decision point for each budget period (12 to 18-month period) of the project. The applicant should also provide the specific objective criteria to be used to evaluate the project at the Go/No-Go decision point. The summary provided should be consistent with the SOPO. Go/No-Go decision points are considered "SMART" and can fulfill the requirement for an annual SMART milestone. • End of Project Goal: The applicant should provide a summary of the end of project goal(s). At a minimum, each project must have one SMART end

	of project goal. The summary provided should be consistent with the SOPO.
	• Project Schedule (Gantt Chart or similar): The applicant should provide a schedule for the entire project, including task and subtask durations, milestones, and Go/No-Go decision points.
	• Buy America Requirements for Infrastructure Projects: Within the first 2 pages of the Workplan or project description, include a short statement on whether the project will involve the construction, alteration, maintenance and/or repair of public infrastructure in the United States. See Appendix C for applicable definitions and other information regarding Infrastructure Projects and the Buy America Requirement.
	• Project Management: The applicant should discuss the team's proposed management plan, including the following:
	  ○ The overall approach to and organization for managing the work
	  ○ The roles of each project team member
	  ○ Any critical handoffs/interdependencies among project team members
	  ○ The technical and management aspects of the management plan, including systems and practices, such as financial and project management practices
	  ○ The approach to project risk management, including a plan for securing a qualified workforce and mitigating risks to project performance including but not limited to community or labor disputes.
	  ○ A description of how project changes will be handled
	  ○ If applicable, the approach to Quality Assurance/Control
	  ○ How communications will be maintained among project team members

Technical Qualifications and Resources (Approximately 20% of the Technical Volume)	The Technical Qualifications and Resources should contain the following information: • Describe the project team's unique qualifications and expertise, including those of key subrecipients. • Describe the project team's existing equipment and facilities, or equipment or facilities already in place on the proposed project site, that will facilitate the successful completion of the proposed project; include a justification of any new equipment or facilities requested as part of the project. • This section should also include relevant, previous work efforts, demonstrated innovations, and how these enable the applicant to achieve the project objectives. • Describe the time commitment of the key team members to support the project.

	• Describe the technical services to be provided by DOE/NNSA FFRDCs, if applicable.

v. Resumes

A resume provides information that can be used by reviewers to evaluate the individual's skills and experience of the key project personnel. Applicants are required to submit two-page resumes for each project manager and key personnel that include the following:

1. Contact Information;
2. Education: Include all academic institutions attended, major/area, degree;
3. Training: (e.g.,) certification or credential from a Registered Apprenticeship or Labor Management Partnership
4. Professional Experience: Beginning with the current position, list professional/academic positions in chronological order with a brief description;
5. List all current academic, professional, or institutional appointments, foreign or domestic, at the applicant institution or elsewhere, whether or not remuneration is received, and, whether full-time, part-time, or voluntary; and
6. There should be no lapses in time over the past ten years or since age 18, which ever time period is shorter.

Save the resumes in a single PDF file using the following convention for the title "Resumes.pdf" and click on "Add Optional Other Attachment" to attach.

vi. Letters of Commitment

Submit letters of commitment from all subrecipient and third-party cost share providers. If applicable, also include any letters of commitment from suppliers/partners/end users/future customers/labor unions/community-based organizations (one-page maximum per letter). Save the letters of commitment in a single PDF file using the following convention for the title "LOC.pdf" and click on "Add Optional Other Attachment" to attach.

Letters of support or endorsement for the project from entities that do not have a substantive role in the project are not required nor desired.

vii. Community Partnership Documentation

In support of the Community Benefits Plan, applicants may submit documentation to demonstrate existing or planned partnerships with community entities, such as, organizations that work with local stakeholders most vulnerable to or affected by the project, such as organizations that carry out workforce development programs, labor unions, Tribal organizations, and community-based organizations that work with disadvantaged communities. The partnership documentation could be in the form of a letter on the partner's letterhead outlining the planned partnership signed by an officer of the entity, a Memorandum of Understanding, or other similar agreement. Such letters must state the specific nature of the partnership and must not be general letters of support. If the applicant intends to enter into Workforce and Community Agreements as part of the Community Benefits Plan, please include letters from proposed partners as appropriate. Each letter must not exceed 1 page. In total, the partnership documentation must not exceed 10 pages. Save the partnership documentation in a single PDF file using the following convention for the title "LeadOrganization_Partner.pdf".

viii. Statement of Project Objectives (SOPO)

Applicants are required to complete a SOPO. A SOPO template is available as Appendix D of the FOA. The SOPO, including the Milestone Table, must not exceed 5 pages when printed using standard 8.5 x 11 paper with 1" margins (top, bottom, left, and right) with font not smaller than 12-point (except in figures or tables, which may be 10-point font). Save the SOPO in a single Microsoft Word file using the following convention for the title "SOPO.doc or docx" and click on "Add Optional Other Attachment" to attach.

ix. Budget Justification Workbook

Applicants are required to complete the Budget Justification Workbook. This workbook is included as an attachment to this announcement for use and to describe the level of detail required in the budget justification. Although the data requested is mandatory, the use of the budget justification workbook is not. Prime recipients must complete each tab of the Budget Justification Workbook for the project as a whole, including all work to be performed by the prime recipient and its subrecipients and contractors. Applicants should include costs associated with required annual audits and incurred cost proposals in their proposed budget documents. The "Instructions and Summary" included with the Budget Justification Workbook will auto-populate as the applicant enters information into the Workbook. Applicants must carefully read the "Instructions and Summary" tab provided within the Budget Justification Workbook. Save the Budget Justification Workbook in a single Microsoft Excel file using the following convention for the title "Recipient_Budget_Justification.xls or xlsx" and click on "Add Optional Other Attachment" to attach.

x. Summary/Abstract for Public Release

Applicants are required to submit a one-page summary/abstract of their project. The project summary/abstract must contain a summary of the proposed activity suitable for dissemination to the public. It should be a self-contained document that identifies the name of the applicant, the project manager, the project title, the objectives of the project, a description of the project, including methods to be employed, the potential impact of the project (e.g., benefits, outcomes), and major participants (for collaborative projects). This document must not include any proprietary or sensitive business information as DOE may make it available to the public after selections are made. The project summary must not exceed 1 page when printed using standard 8.5 x 11 paper with 1" margins (top, bottom, left, and right) with font not smaller than 12-point. Save the Summary for Public Release in a single PDF file using the following convention for the title "Summary.pdf" and click on "Add Optional Other Attachment" to attach.

xi. Summary Slide

Applicants are required to provide up to 3 slides summarizing the proposed project. This slide is used during the evaluation process.

The Summary Slide template requires the following information:

- A technology summary;
- A description of the technology's impact;
- Proposed project goals;
- Any key graphics (illustrations, charts and/or tables);
- The project's key idea/takeaway;
- Project title, prime recipient, project manager and key personnel information; and
- Requested DOE funds and proposed applicant cost share.

Save the Summary Slide in a single Microsoft PowerPoint file using the following convention for the title "Slide.ppt or pptx" and click on "Add Optional Other Attachment" to attach.

xii. Subrecipient Budget Justification (if applicable)

Applicants must provide a separate budget justification for each subrecipient that is expected to perform work estimated to be more than $250,000 or 25 percent of the total work effort (whichever is less). The budget justification must include the same justification information described in the "Budget Justification" section above. Save each subrecipient budget justification in a Microsoft Excel file using the following convention for the title "Subrecipient_Budget_Justification.xls or xlsx" and click on "Add Optional Other Attachment" to attach.

xiii. Environmental Questionnaire

The Applicant must submit an environmental questionnaire providing for the work of the entire project. The Applicant is also responsible for submitting a separate environmental questionnaire for each proposed subrecipient performing at a different location. The environmental questionnaire is available at http://www.netl.doe.gov/File%20Library/Business/forms/451_1-1-3.pdf. Save the questionnaire in a single file named "Env.pdf" (or “Env-FILL IN TEAM MEMBER.pdf” if more than questionnaire is submitted) and click on "Add Optional Other Attachment” to attach.

NOTE: If selected for award and if a subrecipient’s location is not known at the time of application, a subsequent environmental questionnaire will be needed prior to them beginning work at an alternate location.

xiv. SF-LLL: Disclosure of Lobbying Activities (required)

Prime recipients and subrecipients may not use any federal funds to influence or attempt to influence, directly or indirectly, congressional action on any legislative or appropriation matters.

Prime recipients and subrecipients are required to complete and submit SF-LLL, “Disclosure of Lobbying Activities” to ensure that non-federal funds have not been paid and will not be paid to any person for influencing or attempting to influence any of the following in connection with the application:

- An officer or employee of any federal agency;
- A Member of Congress;

xv. Waiver Requests (if applicable)

i. **Foreign Entity Participation**

For projects selected under this FOA, as set forth in Section III, all prime recipients and subrecipients must qualify as domestic entities. To request a waiver of this requirement, the applicant must submit an explicit waiver request in the Full Application. Appendix B lists the information that must be included in a waiver request.

ii. **Performance of Work in the United States (Foreign Work Waiver)**

As set forth in Section IV.I.iii., all work for projects selected under this FOA must be performed in the United States. To request a waiver of this requirement, the applicant must submit an explicit waiver request in the Full Application. Appendix B lists the information that must be included in a foreign work waiver request.

Save the Waivers in a single PDF file using the following convention for the title “FN_Waiver.pdf” and click on “Add Optional Other Attachment” to attach.

iii. **Waiver of the Buy America Requirement for Infrastructure Projects**

As set forth in Section IV.I.vii., federally assisted projects which involve infrastructure work, undertaken by applicable recipient types, require that:

- all iron, steel, and manufactured products used in the infrastructure work are produced in the United States; and
- all construction materials used in the infrastructure work are manufactured in the United States.

The award agreement for funding between DOE and the awardee will require each recipient: (1) to fulfill the commitments made in its application regarding the procurement of U.S.-produced products, subject to a waiver process by DOE assessing the availability and cost (increasing the cost of the overall project by >25%), and (2) to fulfill the commitments made in its application regarding the procurement of other key component metals and manufactured products domestically that are deemed available in sufficient and reasonably available quantities or of a satisfactory quality at the time of award negotiation, again subject to a DOE waiver process.

In limited circumstances, DOE may grant a waiver of this requirement. Appendix C to this FOA provides guidance on how “infrastructure work” is defined, explains the applicable justifications under which a waiver may be granted, and lists the information that must be included in the waiver request.

Save the Waivers in a single PDF file using the following convention for the title “BAWaiver.pdf” and click on “Add Optional Other Attachment” to attach.

xvi. Community Benefits Plan: Job Quality and Equity (Community Benefits Plan)

When Community Benefits Plan: Job Quality and Equity (Community Benefits Plan or Plan) must set forth the applicant’s framework to ensure that federal investments in the power sector advance the following four priorities: (1) community and labor engagement; (2) investing in the American workforce; (3) advancing diversity, equity, inclusion, and accessibility (DEIA); and (4) the Justice40 Initiative. The below sections set forth the Plan requirements in each of the foregoing areas. At this stage of the application process, the Community Benefits Plan should indicate the applicant’s intention to engage meaningfully with labor and community stakeholders on these goals, including the potential of entering into formal Workforce and Community Agreements. Given project complexity and sensitivities, applicants should consider pursuing multiple agreements.

Applicants should complete each portion of the initial Community Benefits Plan to the greatest extent possible. In cases where information is incomplete, applicants should clearly explain the reason for missing information and provide plans to address those gaps during the project. If the applicant has prior or ongoing efforts to advance energy and environmental justice, DEIA, community and labor engagement, or quality jobs, the application should discuss how they are incorporating lessons learned and building on these prior/ongoing efforts. At this stage of the application process, the Community Benefits Plan should indicate the applicant's intention to engage meaningfully with community and labor stakeholders on these goals, including the potential of entering into a formal Workforce and Community Agreement. DOE expects the information contained in the Community Benefits Plan to deepen and evolve during each phase.

The applicant's Community Benefits Plan must include at least one SMART (Specific, Measurable, Assignable, Realistic and Time-Related) milestone per budget period supported by metrics to measure the success of the proposed actions. Each of the four sections should also include information about the resources intended to implement the Community Benefits Plan, including staff time and budget to convene public meetings to engage and negotiate agreements with relevant labor unions, communities, and other stakeholders. The initial Community Benefits Plan should provide the most details regarding actions the applicant would take during the initial stages of project development but should also describe in a higher-level summary what goals, deliverables, outcomes, and implementation strategies the applicant would pursue as the project moves through the development, construction, and operational stages.

The Community Benefits Plan will be evaluated as part of the technical review process. If the project is selected, DOE will incorporate relevant elements of the Community Benefits Plan, including any proposed Workforce and Community Agreement(s), into the award as part of the project requirements. During the life of the DOE award, DOE will evaluate the recipient's progress in formatting and implementing this Plan.

For additional information, see [Community Benefits Plan Frequently Asked Questions (FAQs) | Department of Energy].

1. Community and Labor Engagement: The Community Benefits Plan must set forth the applicant's prior actions and future plans to engage with labor unions, local governments and Tribal entities, and an inclusive collection of local stakeholders, including community-based organizations that support or work with disadvantaged communities. By facilitating community input and social buy-in and strengthening accountability, such agreements substantially reduce or eliminate certain risks associated with the project. These agreements ideally lay the groundwork for the eventual negotiation of Workforce and Community Agreements, which could take the form of one or more kinds of negotiated agreements with communities, labor unions, or, ideally, both. Registered apprenticeship programs, labor-management training partnerships, quality pre-apprenticeship programs, card check neutrality, and local and targeted hiring goals are all examples of provisions that Workforce and Community Agreements could cover that would increase the success of a DOE-funded project.

Applicants should also provide Community and Labor Partnership Documentation from representative organizations reflecting substantive engagement and feedback on applicant's approach to community benefits including job quality and workforce continuity; diversity, equity, inclusion, and accessibility; and the Justice40 Initiative detailed below.

If selected for funding, applicants will be expected to execute on any proposed Workforce and Community Agreements that identify how community and labor concerns, vulnerabilities, and benefits will be addressed.

2. Investing in the American Workforce: A well-qualified, skilled, and trained workforce is necessary to ensure project stability, continuity, and success, and to meet program goals. High-quality jobs are critical to attracting and retaining the qualified workforce required. The Community Benefits Plan must provide an approach to the creation and retention of quality jobs.[48] The Plan is an opportunity for the applicant to detail their approach to investing in the American workforce. Successful applicants will be required to provide more detail and identify SMART milestones to ensure accountability with plan implementation. Letters of support may bolster, but not replace, the descriptions requested below.

Specific components of the plan must include:

1) Summarize the applicant's plan to attract, train, and retain a skilled and well qualified workforce for both (a) construction and (b) ongoing operations/production activities. An available workforce is necessary to ensure project stability, continuity, and success. A collective bargaining

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[48] A "quality job" is defined as a job that (1) exceeds the local prevailing wage for an industry in the region, includes basic benefits (e.g., paid leave, health insurance, retirement/savings plan), and/or is unionized, and (2) helps the employee develop the skills and experiences necessary to advance along a career path. See Economic Development Administration, ARPA Good Jobs Challenge NOFO, EDAHDQ-ARPGJ-2021-2006964, at n. 1, available at https://www.grants.gov/web/grants/viewopportunity.html?oppId=334720.

agreement, labor-management partnership, or other such agreement would provide evidence of such a plan. Alternatively, applicants may describe:

i. Wages, benefits, and other worker supports provided
ii. Commitments to support workforce education and training, including which reduces employee turnover costs for employers, increases productivity from a committed and engaged workforce, and promotes a nimble, resilient, and stable workforce for the project.
iii. Efforts to engage employees in the design and execution of a workplace safety and health plan to safeguard worker health and well-being.

NOTE: Because Project Labor Agreements (PLAs) have been shown to reduce project costs, avoid work delays, and improve efficiency, they are preferred on construction projects of all sizes and may be required for large construction projects (above $35M or possibly lower, on a case-by-case basis). Assessment of applicability will be conducted on a case-by-case basis and in consultation with recipients to ensure project feasibility.

2) Please disclose any violations found within the past two years under the National Labor Relations Act, Fair Labor Standards Act, Occupational Safety and Health Act, Service Contract Act, Davis-Bacon Act, or Title VII of the Civil Rights Act and any steps taken to improve your workforce practices following this violation. Describe whether workers can form and join unions of their choosing, exercising collective voice. Employees' ability to organize, bargain collectively, and participate through labor organizations of their choosing in decisions which affect them, helps build meaningful economic power, safeguard the public interest, contribute to the effective conduct of business, and facilitate amicable settlements of disputes between employees and their employers, thus providing assurances of project efficiency, continuity, and multiple public benefits.

3) Describe the job retention and/or transition and other workforce development opportunities associated with the project noting efforts to create or retain jobs.

3. DEIA: The Community Benefits Plan must include a section describing how DEIA objectives will be incorporated into the project. The section should detail how the applicant will partner with underrepresented businesses, training organizations serving workers facing system barriers to access quality jobs, and other project partners to help address DEIA. The plan should include at least one SMART milestone per Budget Period supported by metrics to measure the success of the proposed actions and will be incorporated into the award if selected.

The following is a non-exhaustive list of potential DEIA actions that can serve as examples of ways the proposed project could incorporate DEIA elements. These examples should not be considered either comprehensive or prescriptive. Applicants may include appropriate actions not covered by these examples and should include a comprehensive set of specific DEIA actions anticipated in connection with the project.

a. Commit to supplier diversity and identify Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, and Veteran Owned Businesses to solicit as vendors and sub-contractors for bids on supplies, services and equipment;
b. Identify and partner with workforce training organizations serving under-represented individuals and those facing barriers to quality employment such as those with disabilities, returning citizens, opportunity youth, and veterans;
c. Offer anti-bias training and education to ensure hiring professionals can recognize unconscious bias and can learn how to reduce discriminatory barriers;
d. Support for quality apprenticeship-readiness and/or pre-apprenticeship programs in the local community that are integrated with registered apprenticeship, including cyber apprenticeship-readiness programs and cyber-registered apprenticeship programs;
e. Provide funding for or partner with organization that can provide comprehensive support services such as training stipends, mental health supports, transportation assistance, and access to child care to improve access to career-track training and quality jobs for underrepresented and disadvantaged workers;
f. Describe Local and/or Economic Hire efforts (e.g., recruitment preferences for economically disadvantaged populations

4. Justice40 Initiative: Applicants must provide an overview of benefits that can be supported by measurable metrics and describe the benefits to DACs. Such benefits framework shall include appropriate milestones for benefit delivery and will be incorporated into the award.

Specifically, the Justice40 Initiative section must include:

1. Identification of applicable disadvantaged communities to which the anticipated project benefits will flow.
2. Identification of applicable benefits that are quantifiable, measurable, and trackable.
    a. Benefits include (but are not limited to) measurable direct or indirect investments or positive project outcomes that achieve or contribute to the following in disadvantaged communities: (1) a decrease in

energy burden; (2) a decrease in environmental exposure and burdens; (3) an increase in access to low-cost capital; (4) an increase in high-quality job creation, the clean energy job pipeline, and job training for individuals; (5) increases in clean energy enterprise creation and contracting (e.g., minority-owned or disadvantaged business enterprises); (6) increases in energy democracy, including community ownership; (7) increased parity in clean energy technology access and adoption; and (8) an increase in energy resilience including reduced outage frequency and/or duration. In addition, applicants, should also discuss how the project will maximize all of the benefits listed herein.

3. A Discussion of Anticipated Negative and Cumulative Environmental Impacts on disadvantaged communities. For example, what are the anticipated environmental impacts associated with the project, and how will the applicant mitigate such impacts? Within the context of cumulative impacts created by the project, applicants should use Environmental Protection Agency EJSCREEN[49] tool to quantitatively discuss existing environmental impacts in the project area.
4. A Description of How and when Anticipated Benefits Are Expected to Flow to disadvantaged communities. For example, will the benefits be provided directly within the disadvantaged communities identified in the Justice40 Initiative Plan, or are the benefits expected to flow in another way? Further, will the benefits flow during project development or after project completion, and how will applicant track benefits delivered?

For projects funded under this FOA, DOE will provide specific reporting guidance for a subset of the eight policy priorities described above; however, recipients must also report how project benefits flow to applicable disadvantaged communities, in furtherance of the advancement of the policy priorities outlined above. For example, a recipient can describe how a project will increase access to clean energy and decrease harmful emissions in disadvantaged communities and provide methods for tracking the progress of these outcomes.

Save the Community Benefits Plan in a single PDF file using the following convention for the title “CBenefits.pdf” and click on “Add Optional Other Attachment” to attach.

xvii. Requirement to Report Potentially Duplicative Funding

If the applicant or project team member has other active awards of federal funds, the applicant must determine whether the activities of those awards potentially overlap with the activities set forth in its application to this FOA. If

[49] Environmental Justice (EJ) Screening and Mapping Tool from the Environmental Protection Agency https://www.epa.gov/ejscreen

there is a potential overlap, the applicant must notify DOE in writing of the potential overlap and state how it will ensure any project funds (i.e., recipient cost share and federal funds) will not be used for identical cost items under multiple awards. Likewise, for projects that receive funding under this FOA, if a recipient or project team member receives any other award of federal funds for activities that potentially overlap with the activities funded under the DOE award, the recipient must promptly notify DOE in writing of the potential overlap and state whether project funds from any of those other federal awards have been, are being, or are to be used (in whole or in part) for one or more of the identical cost items under the DOE award. If there are identical cost items, the recipient must promptly notify the DOE Contracting Officer in writing of the potential duplication and eliminate any inappropriate duplication of funding.

Save the Potential Duplicative Funding Notice in a single PDF file using the following convention for the title “PDFN.pdf” and click on “Add Optional Other Attachment” to attach.

xviii. Report on Resilience Investments (Topic Area 1 ONLY)

Applicants must submit a report detailing past, current, and future efforts by the eligible entity to reduce the likelihood and consequences of disruptive events. The report must summarize any programs and related approved funding that your organization has implemented over the past 3 years to reduce the likelihood of events in which operations of the electric grid are disrupted, preventively shut off, or cannot operate safely due to extreme weather, wildfire, or a natural disaster. The report must also summarize current and future efforts planned over at least the next 3 years to reduce the likelihood and consequences of disruptive events. Save the Report on Resilience Investments in a single PDF file using the following convention for the title “ResilienceInvestments.pdf”.

xix. EIA 861 Report (Topic Area 1, small utilities ONLY)

Applicants who are small utilities applying to Topic Area 1 must submit the EIA Form 861 for the last reporting year showing the total retail electricity sales to ultimate customers to ensure status as a small utility. Save the EIA 861 Report in a single PDF file using the following convention for the title “EIA861.pdf”.

xx. Locations of Work

The applicant must complete the supplied template by listing the city, state, and zip code + 4 for each location where project work will be performed by the prime recipient or subrecipient(s). This template is included as an attachment to this announcement for use. Save the Location of Work in a single Microsoft Excel file using the following naming convention for the title "LOW.xls or xlsx" and click on "Add Optional Other Attachment" to attach

xxi. Project Description and Assurances Document (PDAD)

Applicants for all three topic areas must complete and submit the PDAD. Note that there are requirements specific to Topic Area 1 and Topic Area 3, for which the applicant will respond and certify responses via the PDAD, as described in Section I.B. Applicants shall prepare the PDAD in the format provided in Appendix F of the FOA. The PDAD must be signed by the Authorized Organizational Representative (AOR) on behalf of the organization and be submitted in PDF format. Save the PDAD in a single PDF file using the following convention for the title "PDAD.pdf".

E. Post Selection Information Requests

If selected for award, DOE reserves the right to request additional or clarifying information regarding the following (non-exhaustive list):

- Personnel proposed to work on the project and collaborating organizations (See Section VI.B.xix. Participants and Collaborating Organizations);
- An Intellectual Property Management Plan (if applicable) describing how the project team/consortia members will handle intellectual property rights and issues between themselves while ensuring compliance with federal intellectual property laws, regulations, and policies in accordance with VI.B.xi Intellectual Property Management Plan;
- Indirect cost information;
- Other budget information;
- Commitment Letters from Third Parties Contributing to Cost Share, if applicable;
- Name and phone number of the Designated Responsible Employee for complying with national policies prohibiting discrimination (See 10 CFR 1040.5);
- Representation of Limited Rights Data and Restricted Software, if applicable;
- Information related to Davis-Bacon Act Requirements;
- Information related to Community Benefits Agreements, as defined above in "Community Benefits Plan: Jobs Quality and Equity," that applicants may have made with the relevant community;
- Updated Environmental Questionnaire(s).

F. Unique Entity Identifier (UEI) and System for Award Management (SAM)

Each applicant (unless the applicant is an individual or federal awarding agency that is excepted from those requirements under 2 CFR 25.110(b) or (c), or has an exception approved by the federal awarding agency under 2 CFR 25.110(d)) is required to: (1) Be registered in the SAM at https://www.sam.gov before submitting its application; (2) provide a valid UEI number in its application; and (3) continue to maintain an active SAM registration with current information at all times during which it has an active federal award or an application or plan under consideration by a federal awarding agency. DOE may not make a federal award to an applicant until the applicant has complied with all applicable UEI and SAM requirements and, if an applicant has not fully complied with the requirements by the time DOE is ready to make a federal award, the DOE will determine that the applicant is not qualified to receive a federal award and use that determination as a basis for making a federal award to another applicant.

G. Submission Dates and Times

All required submissions must be submitted as specifically stated in the announcement no later than 5 p.m. ET on the dates provided on the cover page of this FOA.

H. Intergovernmental Review

This FOA is not subject to Executive Order 12372 – Intergovernmental Review of Federal Programs.

I. Funding Restrictions

i. Allowable Costs

All expenditures must be allowable, allocable, and reasonable in accordance with the applicable federal cost principles. Pursuant to 2 CFR 910.352, the cost principles in the Federal Acquisition Regulations (48 CFR Part 31.2) apply to for-profit entities. The cost principles contained in 2 CFR Part 200, Subpart E apply to all entities other than for-profits. Costs to support or oppose union organizing, whether directly or as an offset for other funds, are unallowable.

ii. Pre-Award Costs

Applicants selected for award negotiations (selectee) must request prior written approval to charge pre-award costs. Pre-award costs are those incurred prior to the effective date of the federal award directly pursuant to the negotiation and in anticipation of the federal award where such costs are necessary for efficient and timely performance of the scope of work. Such costs are allowable only to the extent that they would have been allowable if incurred after the date of the federal award and **only** with the written approval of the federal awarding agency, through the DOE Contracting Officer.

Pre-award costs cannot be incurred prior to the Selection Official signing the Selection Statement and Analysis.

Pre-award expenditures are made at the selectee's risk. DOE is not obligated to reimburse costs: (1) in the absence of appropriations; (2) if an award is not made; or (3) if an award is made for a lesser amount than the selectee anticipated.

1. **National Environmental Policy Act (NEPA) Requirements Related to Pre-Award Costs**
   DOE's decision whether and how to distribute federal funds under this FOA is subject to NEPA. Applicants should carefully consider and should seek legal counsel or other expert advice before taking any action related to the proposed project that would have an adverse effect on the environment or limit the choice of reasonable alternatives prior to DOE completing the NEPA review process.

   DOE does not guarantee or assume any obligation to reimburse pre-award costs incurred prior to receiving written authorization from the Contracting Officer. If the applicant elects to undertake activities that DOE determines may have an adverse effect on the environment or limit the choice of reasonable alternatives prior to receiving such written authorization from the Contracting Officer, the applicant is doing so at risk of not receiving federal funding for their project and such costs may not be recognized as allowable cost share. Nothing contained in the pre-award cost reimbursement regulations or any pre-award costs approval letter from the Contracting Officer override the requirement to obtain the written authorization from the Contracting Officer prior to taking any action that may have an adverse effect on the environment or limit the choice of reasonable alternatives. Likewise, if an application is selected for negotiation of award, and the prime recipient elects to undertake activities that are not authorized for federal funding by the Contracting Officer in advance of DOE completing a NEPA review, the prime recipient is doing so at risk of not receiving federal funding and such costs may not be recognized as allowable cost share.

iii. Performance of Work in the United States (Foreign Work Waiver)

1. **Requirement**
   All work performed under DOE awards issued under this FOA must be performed in the United States. The prime recipient must flow down this requirement to its subrecipients.

2. **Failure to Comply**

If the prime recipient fails to comply with the Performance of Work in the United States requirement, DOE may deny reimbursement for the work conducted outside the United States and such costs may not be recognized as allowable recipient cost share. The prime recipient is responsible should any work under this award be performed outside the United States, absent a waiver, regardless of whether the work is performed by the prime recipient, subrecipients, contractors or other project partners.

3. Waiver

To seek a foreign work waiver, the applicant must submit a written waiver request to DOE. <u>Appendix B lists the information that must be included in a request for a foreign work waiver</u>.

Save the waiver request(s) in a single PDF file. The applicant does not have the right to appeal DOE's decision concerning a waiver request.

iv. Construction

Recipients are required to obtain written authorization from the Contracting Officer before incurring any major construction costs.

v. Foreign Travel

Foreign travel costs are not allowable under this FOA.

vi. Equipment and Supplies

Property disposition may be required at the end of a project if the current fair market value of property exceeds $5,000. For-profit entity disposition requirements are set forth at 2 CFR 910.360. Property disposition requirements for other non-federal entities are set forth in 2 CFR 200.310 – 200.316.

vii. Buy America Requirements for Infrastructure Projects

Awards funded through this FOA that are for, or contain, construction, alteration, maintenance or repair of public infrastructure in the United States, undertaken by applicable recipient types, require that:

- All iron, steel, and manufactured products used in the infrastructure project are produced in the United States; and
- All construction materials used in the infrastructure project are manufactured in the United States.

In general, whether a given project must apply this requirement is dependent on several factors, such as the recipient's entity type, whether the work involves "infrastructure," as that term is defined in Section 70914 of the BIL (discussed in more detail in Appendix C), based in part on whether the infrastructure in question is publicly owned or serves a public function. For this FOA specifically, all projects subject to this FOA are considered "infrastructure" within the Buy America provision of BIL, based on implementation guidance from Office of Management and Budget (OMB) Memorandum M-22-11 issued on April 18, 2022.

Moreover, based on M-22-11, the Buy America requirements of the BIL do not apply to DOE projects in which the prime recipient is a for-profit entity; the requirements only apply to projects whose prime recipient is a "non-Federal entity," e.g., a State, local government, Indian Tribe, Institution of Higher Education, or nonprofit organization. Subawards should conform to the terms of the prime award from which they flow; in other words, for-profit prime recipients are not required to flow down these Buy America requirements to subrecipients, even if those subrecipients are non-Federal entities as defined above. Conversely, prime recipients which are non-Federal entities must flow the Buy America requirements down to all subrecipients, even if those subrecipients are for-profit entities. Finally, for all applicants—both non-Federal entities and for-profit entities—DOE is including a Program Policy Factor that the Selection Official may consider in determining which Full Applications to select for award negotiations that considers whether the applicant has made a commitment to procure U.S. iron, steel, manufactured products, and construction materials in its project.

The Cooperative Agreement between DOE and the awardee will require each recipient: (1) to fulfill the commitments made in its application regarding the procurement of U.S.-produced products, and (2) to fulfill the commitments made in its application regarding the procurement of other key component metals and manufactured products domestically that are deemed available in sufficient and reasonably available quantities or of a satisfactory quality at the time of award negotiation. Applicants may seek waivers of these requirements in very limited circumstances and for good cause shown. Further details on requesting a waiver can be found in Appendix C and the terms and conditions of the applicant's award.

Applicants are strongly encouraged to consult Appendix C for more information.

viii. Davis-Bacon Act Requirements

Projects awarded under this FOA will be funded under Division D of the Bipartisan Infrastructure Law. Accordingly, per section 41101 of that law, all laborers and mechanics employed by the applicant, subrecipients, contractors or subcontractors in the performance of construction, alteration, or repair work funded in whole or in part under this FOA shall be paid wages at rates not less than those prevailing on similar projects in the locality, as determined by the Secretary of Labor in accordance with subchapter IV of chapter 31 of title 40, United States Code commonly referred to as the "Davis-Bacon Act" (DBA).

Applicants shall provide written assurance acknowledging the DBA requirements above, and confirming that the laborers and mechanics performing construction, alteration, or repair work on projects funded in whole or in part by awards made as a result of this FOA are paid or will be paid wages at rates not less than those prevailing on projects of a character similar in the locality as determined by subchapter IV of Chapter 31 of Title 40, United States Code (Davis-Bacon Act).

Applicants acknowledge that they will comply with all of the Davis-Bacon Act requirements, including but not limited to:

(1) ensuring that the wage determination(s) and appropriate Davis-Bacon clauses and requirements are flowed down to and incorporated into any applicable subcontracts or subrecipient awards.

(2) ensuring that if wage determination(s) and appropriate Davis-Bacon clauses and requirements are improperly omitted from contracts and subrecipient awards, the applicable wage determination(s) and clauses are retroactively incorporated to the start of performance.

(3) being responsible for compliance by any subcontractor or subrecipient with the Davis-Bacon labor standards.

(4) receiving and reviewing certified weekly payrolls submitted by all subcontractors and subrecipients for accuracy and to identify potential compliance issues.

(5) maintaining original certified weekly payrolls for 3 years after the completion of the project and must make those payrolls available to the DOE or the Department of Labor upon request, as required by 29 CFR 5.6(a)(2).

(6) conducting payroll and job-site reviews for construction work, including interviews with employees, with such frequency as may be necessary to assure compliance by its subcontractors and subrecipients and as requested or directed by the DOE.

(7) cooperating with any authorized representative of the Department of Labor in their inspection of records, interviews with employees, and other actions undertaken as part of a Department of Labor investigation.

(8) posting in a prominent and accessible place the wage determination(s) and Department of Labor Publication: WH-1321, Notice to Employees Working on Federal or Federally Assisted Construction Projects.

(9) notifying the Contracting Officer of all labor standards issues, including all complaints regarding incorrect payment of prevailing wages and/or fringe benefits, received from the recipient, subrecipient, contractor, or subcontractor employees; significant labor standards violations, as defined in 29 CFR 5.7; disputes concerning labor standards pursuant to 29 CFR parts 4, 6, and 8 and as defined in FAR 52.222-14; disputed labor standards determinations; Department of Labor investigations; or legal or judicial proceedings related to the labor standards under this Contract, a subcontract, or subrecipient award.

(10) preparing and submitting to the Contracting Officer, the Office of Management and Budget Control Number 1910-5165, Davis Bacon Semi-Annual Labor Compliance Report, by April 21 and October 21 of each year. Form submittal will be administered through the iBenefits system (https://doeibenefits2.energy.gov) or its successor system.

Recipients of funding under this FOA will also be required to undergo Davis-Bacon Act compliance training and to maintain competency in Davis-Bacon Act compliance. The Contracting Officer will notify the recipient of any DOE sponsored Davis-Bacon Act compliance trainings. The U.S. Department of Labor ("DOL") offers free Prevailing Wage Seminars several times a year that meet this requirement, at https://www.dol.gov/agencies/whd/government-contracts/construction/seminars/events.

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

DOE anticipates contracting with a third party for a Davis-Bacon Act electronic payroll compliance software application. Recipients of funding under this FOA must ensure the timely electronic submission of weekly certified payrolls through this software as part of its compliance with the Davis-Bacon Act unless a waiver is granted to a particular contractor or subcontractor because they are unable or limited in their ability to use or access. Applicants should indicate if a waiver will be sought.

ix. Lobbying

Recipients and subrecipients may not use any federal funds to influence or attempt to influence, directly or indirectly, congressional action on any legislative or appropriation matters.

Recipients and subrecipients are required to complete and submit SF-LLL, "Disclosure of Lobbying Activities" (https://www.grants.gov/web/grants/forms/sf-424-individual-family.html) to ensure that non-federal funds have not been paid and will not be paid to any person for influencing or attempting to influence any of the following in connection with the application:

- An officer or employee of any federal agency;
- A Member of Congress;
- An officer or employee of Congress; or
- An employee of a Member of Congress.

x. Risk Assessment

Pursuant to 2 CFR 200.206, DOE will conduct an additional review of the risk posed by applicants submitted under this FOA. Such risk assessment will consider:

1. Financial stability;
2. Quality of management systems and ability to meet the management standards prescribed in 2 CFR 200 as amended and adopted by 2 CFR 910;
3. History of performance;
4. Audit reports and findings; and
5. The applicant's ability to effectively implement statutory, regulatory, or other requirements imposed on non-federal entities.

DOE may make use of other publicly available information and the history of an applicant's performance under DOE or other federal agency awards.

Depending on the severity of the findings and whether the findings were resolved, DOE may elect not to fund the applicant.

In addition to this review, DOE must comply with the guidelines on government-wide suspension and debarment in 2 CFR 180 and must require non-federal entities to comply with these provisions. These provisions restrict federal awards, subawards and contracts with certain parties that are debarred, suspended or otherwise excluded from or ineligible for participation in federal programs or activities.

Further, as DOE funds critical and emerging technology areas, DOE also considers possible vectors of undue foreign influence in evaluating risk. If high risks are identified and cannot be sufficiently mitigated, DOE may elect to not fund the applicant.

xi. Invoice Review and Approval

DOE employs a risk-based approach to determine the level of supporting documentation required for approving invoice payments. Recipients may be required to provide some or all of the following items with their requests for reimbursement:

- Summary of costs by cost categories;
- Timesheets or personnel hours report;
- Proof of compliance with Davis-Bacon and electronic submittals of certified payroll reports;
- Disclosure of any citations related to NLRA, FLSA, OSH, SCA, or DBA, or Title VII;
- Invoices/receipts for all travel, equipment, supplies, contractual, and other costs;
- UCC filing proof for equipment acquired with project funds by for-profit recipients and subrecipients;
- Explanation of cost share for invoicing period;
- Analogous information for some subrecipients; and
- Other items as required by DOE.

xii. Prohibition related to Foreign Government-Sponsored Talent Recruitment Programs

a. Prohibition

Persons participating in a Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk are prohibited from participating in projects selected for federal funding under this FOA. Should an award result from this FOA, the recipient must exercise ongoing due diligence to reasonably ensure that no individuals participating on the DOE-funded project are participating in a Foreign Government-Sponsored Talent Recruitment Program of a Foreign Country of Risk. Consequences for violations of this prohibition will be determined according to applicable law, regulations, and policy. Further, the recipient must notify DOE within five (5) business days upon learning that an individual on the project team is or is believed to be participating in a foreign government talent recruitment program of a foreign country of risk. DOE may modify and add requirements related to this prohibition to the extent required by law.

b. Definitions

1. **Foreign Government-Sponsored Talent Recruitment Program.** An effort directly or indirectly organized, managed, or funded by a foreign government, or a foreign government instrumentality or entity, to recruit science and technology professionals or students (regardless of citizenship or national origin, or whether having a full-time or part-time

position). Some foreign government-sponsored talent recruitment programs operate with the intent to import or otherwise acquire from abroad, sometimes through illicit means, proprietary technology or software, unpublished data and methods, and intellectual property to further the military modernization goals and/or economic goals of a foreign government. Many, but not all, programs aim to incentivize the targeted individual to relocate physically to the foreign state for the above purpose. Some programs allow for or encourage continued employment at U.S. research facilities or receipt of Federal research funds while concurrently working at and/or receiving compensation from a foreign institution, and some direct participants not to disclose their participation to U.S. entities. Compensation could take many forms including cash, research funding, complimentary foreign travel, honorific titles, career advancement opportunities, promised future compensation, or other types of remuneration or consideration, including in-kind compensation.

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

xiii. Affirmative Action and Pay Transparency Requirements

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

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

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

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

The Department of Labor's (DOL) Office of Federal Contractor Compliance Programs (OFCCP) uses a neutral process to schedule contractors for compliance evaluations. OFCCP's Technical Assistance Guide[50] should be consulted to gain an understanding of the requirements and possible actions the recipients, subrecipients, contractors and subcontractors must take.

Additionally, for construction projects valued at $35 million or more and lasting more than one year, the recipients, subrecipients, contractors and subcontractors may be assigned by OFCCP as a mega construction project and may be neutrally selected for a compliance evaluation by OFCCP.[51]

V. Application Review Information

A. Technical Review Criteria

i. Concept Papers

Concept Papers are evaluated based on consideration the following factors. All sub-criteria are of equal weight.

Applicable to All Topic Areas

Concept Paper Criterion: Overall FOA Responsiveness and Viability of the Project (Weight: 100%)

This criterion involves consideration of the following factors:

- The proposed work, if successfully accomplished, would clearly meet the objectives as stated in the FOA for the specific topic area.
- The proposed work aligns with and supports State, local, Tribal, regional resilience, decarbonization, or other energy strategies and plans.
- The applicant has identified risks and challenges, including possible mitigation strategies, and has shown the impact that DOE funding and the proposed project would have on the relevant field and application.
- The applicant has proposed strategies to ensure meaningful community and labor engagement; quality jobs and workforce development; EEJ and the Justice40 Initiative; and diversity, inclusion, accessibility—including methods to ensure accountability.
- The applicant has the qualifications, experience, capabilities and other resources necessary to complete the proposed project.

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[50] See OFCCP's Technical Assistance Guide at: https://www.dol.gov/sites/dolgov/files/ofccp/Construction/files/ConstructionTAG.pdf?msclkid=9e397d68c4b111ec9d8e6fecb6c710ec Also see the National Policy Assurances http://www.nsf.gov/awards/managing/rtc.jsp

[51] For more information regarding this program, see https://www.dol.gov/agencies/ofccp/construction/mega-program.

ii. Full Applications

Applications will be evaluated against the technical review criteria shown below. All sub-criteria are of equal weight.

Criterion 1 for Topic Area 1: Impact, Transformation, and Technical Merit (50%):
This criterion involves consideration of the following factors:

- Extent to which the project supports the Topic Area 1 objectives and desired outcomes.
- The magnitude of the community or regional resilience benefit that the project will generate by reducing the likelihood and consequences of disruptive events.
- The extent to which the has application specifically and convincingly demonstrates the applicant's technical ability to:
    - comprehensively mitigate one or more hazards faced by community or region
    - fully mitigate the potential for equipment to cause a wildfire in a community or region
    - minimize the consequences of an outage caused by a natural hazard
    - minimize economic impact resulting from outage duration or outage frequency.
- Extent to which project supports and works in tandem with State, local, Tribal, regional resilience, decarbonization, or other energy strategies and plans.
- Extent to which the project aligns with and is additive to the current resilience investments described by the applicant outlined in the Report on Resilience Investments.
- Sufficiency of technical detail to demonstrate that the proposed project is technically feasible and would likely result in the described community or regional resilience benefits.
- The potential impact of the project to lead to catalyze additional private sector investments and/or non-federal public or regulated capital.

Criterion 2 for Topic Area 1: Project Plan and Project Financial Feasibility (20%)
This criterion involves consideration of the following factors:

Project Approach, Workplan, and Statement of Project Objectives (SOPO)

- Degree to which the approach and critical path have been clearly described and thoughtfully considered.

- Degree to which the task descriptions are clear, detailed, timely, and reasonable, resulting in a high likelihood that the proposed Workplan and SOPO will succeed in meeting the project goals.

Identification of Risks

- Discussion and demonstrated understanding of the key anticipated risks (e.g. technical, financial, market, environmental, regulatory) involved in the proposed work and the quality of the mitigation strategies to address them.

Baseline, Metrics, and Deliverables

- The level of clarity in the definition of the baseline, metrics, and milestones.
- Relative to a clearly defined baseline, the strength of the quantifiable metrics, milestones, and mid-point deliverables defined in the application, such that meaningful interim progress will be made.

Project Financial Feasibility

- The reasonableness of the budget and spend plan for the proposed project and objectives.
- Soundness of proposed cost share; level of dedication as demonstrated by letter(s) of commitment that clearly identify type and amount of proposed cost share. Proposed cost share meets requirements outlined in the FOA.
- The degree to which the proposed project yields additive benefit(s) from the federal funding to undertake additional efforts that would not be taken but-for the funding or to accelerate or expand planned activities that would not be accelerated or expanded but-for the funding.
- The degree to which the applicant justifies the project's economic viability.
- The degree to which the project provides enhanced system value and/or provides improved current and future system cost-effectiveness and delivers economic benefit.

Criterion 3 for Topic Area 1: Management Team and Project Partners (10%)
This criterion involves consideration of the following factors:

Project Management

- Clarity and appropriateness of the roles and responsibilities of the project management organization and the project team, including relevant and critical subrecipients and vendors.

- The capability of the Project Manager(s) and the proposed team to manage and address all aspects of the proposed work with a high probability of success.
- The qualifications, relevant expertise, and time commitment of the individuals on the team.
- The level of participation by project participants as evidenced by letter(s) of commitment and how well they are integrated into the Project Plan/Workplan.
- The degree to which the applicant has defined and described a project management structure that addresses interfaces with DOE.

Partners

- Degree to which the applicant includes partnerships with critical entities that will help ensure project success, as well as any partnerships with entities (including other states) outside of the applicant's jurisdiction, who will commit to encourage asset operators (e.g., utilities, merchant developers) to replicate the proposed approaches, technologies or solutions, as applicable.

Criterion 4 for Topic Area 1: Community Benefits Plan (20%)
Every BIL-funded project is expected to contribute to the country's energy infrastructure modernization goals, energy technology demonstration and deployment goals, and climate goals, and also to (1) support meaningful community and labor engagement; (2) support quality jobs and ensure workforce continuity; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the Justice40 Initiative's goal that 40% of the overall project benefits flow to disadvantaged communities.

To ensure these goals are met, applications must include a Community Benefits Plan that illustrates how the proposed project plans to incorporate the four goals stated above and are encouraged to submit Community Partnership Documentation from established labor unions, Tribal entities, and community-based organizations that demonstrate the applicant's ability to achieve the above goals as outlined in the Community Benefits Plan.

This criterion involves consideration of the following factors:

Community and Labor Engagement

- Extent to which the applicant demonstrates community and labor engagement to date that results in support for the proposed project.
- Extent to which the applicant has a clear and appropriately robust plan to engage—ideally through a clear commitment to negotiate an enforceable Workforce & Community Agreements--with labor unions, Tribal entities,

and community-based organizations that support or work with disadvantaged communities and other affected stakeholders.

- Extent to which the applicant has considered accountability to affected workers and community stakeholders, including those most vulnerable to project activities with a plan to publicly share SMART community benefits plan commitments.
- Extent to which the applicant demonstrates that community and labor engagement will lead to the delivery of high-quality jobs, minimal environmental impact, and allocation of project benefits to disadvantaged communities.

Quality Jobs

- Quality and manner in which the proposed project will create and/or retain high quality, good-paying jobs with employer-sponsored benefits for all classifications and phases of work.
- Extent to which the project provides employees with the ability to organize, bargain collectively, and participate, through labor. organizations of their choosing, in decisions that affect them and that contribute to the effective conduct of business and facilitates amicable settlements of any potential disputes between employees and employers, providing assurances of project efficiency, continuity, and multiple public benefits.
- Extent to which applicant demonstrates that they are a responsible employer, with ready access to a sufficient supply of appropriately skilled labor, and an effective plan to minimize the risk of labor disputes or disruptions.

Diversity, Equity, Inclusion, and Accessibility (DEIA)

- The quality and manner in which the proposed project incorporates and measures diversity, equity, inclusion and accessibility goals in the project, as reflected in the applicant’s Community Benefits Plan.
- Extent to which the project supports the development or demonstration in disadvantaged communities, supports existing minority business enterprises (MBEs) or promotes the creation of MBEs and underrepresented businesses in disadvantaged communities.
- Quality of any partnerships and agreements with apprenticeship readiness programs, or community-based workforce training and support organizations serving workers facing systematic barriers to employment to facilitate participation in the project’s construction and operations.
- Extent of engagement of organizations that represent underserved communities as core element of their mission to include Minority Serving Institutions (MSIs), MBEs, associations, and non-profit organizations.

- Extent to which the project illustrates the ability to meet or exceed the objectives of the Justice40 initiative, including the extent to which the project benefits disadvantaged, underserved communities or partners with Tribal Nations.

Justice40 Initiative

- Extent to which the Community Benefits Plan identifies: specific, measurable benefits for disadvantaged communities, how the benefits will flow to disadvantaged communities, and how negative environmental impacts affecting disadvantaged communities would be mitigated.
- Extent to which the project would contribute to meeting the objective that 40% of the benefits of climate and clean energy investments flow to disadvantaged communities.

Criterion 1 Topic Area 2: Impact, Transformation, and Technical Merit (50%):
This criterion involves consideration of the following factors:

- Extent to which the project supports the Topic Area 2 objectives and desired outcomes.
- Extent to which the project deploys technology solutions that address Topic Area 2 priority investments.
- Extent to which the project deploys technology solutions that increase the flexibility, efficiency, reliability and resilience of the electric power system.
- Extent to which the project supports State, local, Tribal, regional resilience, decarbonization, or other energy strategies and plans.
- Extent to which the application provides sufficient technical detail to demonstrate that the proposed project is technically feasible and would likely result in the described smart grid benefits.
- The potential impact of the project to reduce risk for deployment of innovative technologies or solutions and lead to further deployment at-scale.
- The potential impact of the project to catalyze additional private sector investments and/or non-federal public or regulated capital.

Criterion 2 for Topic Area 2: Project Plan and Project Financial Feasibility (20%)
This criterion involves consideration of the following factors:

Project Approach, Workplan, and Statement of Project Objectives (SOPO)

- Degree to which the approach and critical path have been clearly described and thoughtfully considered.
- Degree to which the task descriptions are clear, detailed, timely, and reasonable, resulting in a high likelihood that the proposed Workplan and SOPO will succeed in meeting the project goals.

Identification of Risks

- Discussion and demonstrated understanding of the key anticipated risks (e.g., technical, financial, market, environmental, regulatory) involved in the proposed work and the quality of the mitigation strategies to address them.

Baseline, Metrics, and Deliverables

- The level of clarity in the definition of the baseline, metrics, and milestones.
- Relative to a clearly defined baseline, the strength of the quantifiable metrics, milestones, and mid-point deliverables defined in the application, such that meaningful interim progress will be made.

Project Financial Feasibility

- The reasonableness of the budget and spend plan for the proposed project and objectives.
- Soundness of proposed cost share; level of dedication as demonstrated by letter(s) of commitment that clearly identify type and amount of proposed cost share. Proposed cost share meets requirements outlined in the FOA.
- The degree to which the proposed project yields additive benefit(s) from the federal funding to undertake additional efforts that would not be taken but-for the funding or to accelerate or expand planned activities that would not be accelerated or expanded but-for the funding.
- The degree to which the applicant justifies the project's economic viability.
- The degree to which the project provides enhanced system value and/or provides improved current and future system cost-effectiveness and delivers economic benefit.

Criterion 3 for Topic Area 2: Management Team and Project Partners (10%)
This criterion involves consideration of the following factors:

Project Management

- Clarity and appropriateness of the roles and responsibilities of the project management organization and the project team, including relevant and critical subrecipients and vendors.

- The capability of the Project Manager(s) and the proposed team to manage and address all aspects of the proposed work with a high probability of success.
- The qualifications, relevant expertise, and time commitment of the key individuals on the team.
- The level of participation by project participants as evidenced by letter(s) of commitment and how well they are integrated into the Project Plan/Workplan.
- The degree to which the applicant has defined and described a project management structure that addresses interfaces with DOE.

Partners

- Degree to which the applicant includes partnerships with critical entities that will help ensure project success, as well as any partnerships with entities (including other states) outside of the applicant's jurisdiction, who will commit to encourage asset operators (e.g., utilities, merchant developers) to replicate the proposed approaches, technologies or solutions, as applicable.

Criterion 4 for Topic Area 2: Community Benefits Plan (20%)

Every BIL-funded project is expected to contribute to the country's energy infrastructure modernization goals, energy technology demonstration and deployment goals, and climate goals, and also to (1) support meaningful community and labor engagement; (2) support quality jobs and ensure workforce continuity; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the Justice40 Initiative's goal that 40% of the overall project benefits flow to disadvantaged communities.

To ensure these goals are met, applications must include a Community Benefits Plan that illustrates how the proposed project plans to incorporate the four goals stated above and are encouraged to submit Community Partnership Documentation from established labor unions, Tribal entities, and community-based organizations that demonstrate the applicant's ability to achieve the above goals as outlined in the Community Benefits Plan.

This criterion involves consideration of the following factors:

Community and Labor Engagement

- Extent to which the applicant demonstrates community and labor engagement to date that results in support for the proposed project.
- Extent to which the applicant has a clear and appropriately robust plan to engage—ideally through a clear commitment to negotiate an enforceable Workforce & Community Agreements--with labor unions, Tribal entities,

and community-based organizations that support or work with disadvantaged communities and other affected stakeholders.

- Extent to which the applicant has considered accountability to affected workers and community stakeholders, including those most vulnerable to project activities with a plan to publicly share SMART community benefits plan commitments.
- Extent to which the applicant demonstrates that community and labor engagement will lead to the delivery of high-quality jobs, minimal environmental impact, and allocation of project benefits to disadvantaged communities.

<u>Quality Jobs</u>

- Quality and manner in which the proposed project will create and/or retain high quality, good-paying jobs with employer-sponsored benefits for all classifications and phases of work.
- Extent to which the project provides employees with the ability to organize, bargain collectively, and participate, through labor organizations of their choosing, in decisions that affect them and that contribute to the effective conduct of business and facilitates amicable settlements of any potential disputes between employees and employers, providing assurances of project efficiency, continuity, and multiple public benefits.
- Extent to which applicant demonstrates that they are a responsible employer, with ready access to a sufficient supply of appropriately skilled labor, and an effective plan to minimize the risk of labor disputes or disruptions.

<u>Diversity, Equity, Inclusion, and Accessibility (DEIA)</u>

- The quality and manner in which the proposed project incorporates and measures diversity, equity, inclusion and accessibility goals in the project, as reflected in the applicant's Community Benefits Plan.
- Extent to which the project supports the development or demonstration in disadvantaged communities, supports existing minority business enterprises (MBEs) or promotes the creation of MBEs and underrepresented businesses in disadvantaged communities.
- Quality of any partnerships and agreements with apprenticeship readiness programs, or community-based workforce training and support organizations serving workers facing systematic barriers to employment to facilitate participation in the project's construction and operations.
- Extent of engagement of organizations that represent underserved communities as core element of their mission to include Minority Serving Institutions (MSIs), MBEs, associations, and non-profit organizations.

- Extent to which the project illustrates the ability to meet or exceed the objectives of the Justice40 initiative, including the extent to which the project benefits disadvantaged, underserved communities or partners with Tribal Nations.

Justice40 Initiative

- Extent to which the Community Benefits Plan identifies: specific, measurable benefits for disadvantaged communities, how the benefits will flow to disadvantaged communities, and how negative environmental impacts affecting disadvantaged communities would be mitigated.
- Extent to which the project would contribute to meeting the objective that 40% of the benefits of climate and clean energy investments flow to disadvantaged communities.

Criterion 1 for Topic Area 3: Impact and Market Viability (50%)
This criterion involves consideration of the following factors:

- Extent to which the project supports Topic Area 3 objectives and will deliver the desired Topic Area 3 outcomes.
- Extent to which the project demonstrates innovative approaches to support deployment goals across transmission system, distribution system, storage or a combination to achieve Topic Area 3 primary objectives.
- Extent to which the project clearly enhances collaboration between eligible entities and owners/operators to meet Topic Area 3 objectives.
- Extent to which the project offers the greatest public benefit with a clear path to replication, scale and ability to ensure electricity system reliability and/or resilience, provide enhanced system value and economic benefit, and contribute to the decarbonization of the electricity and broader energy systems.
- Extent that the project has the potential to deliver near-term impact.
- Extent to which project supports State, local, Tribal, and regional resilience, decarbonization, or other energy strategies and plans.
- The potential impact of the project to increase adoption of innovative approach(es), for example to lead to more widespread deployment of advanced technologies; innovative partnerships; new financial arrangements; increased non-Federal investment; deployment of projects identified by innovative planning, modeling, or cost allocation approaches; and/or innovative environmental siting, permitting strategies, or community engagement practices.

Criterion 2 for Topic Area 3: Project Plan and Project Financial Feasibility (20%)

This criterion involves consideration of the following factors.

Project Approach, Workplan, and Statement of Project Objectives (SOPO)

- Degree to which the approach and critical path have been clearly described and thoughtfully considered.
- Degree to which the task descriptions are clear, detailed, timely, and reasonable, resulting in a high likelihood that the proposed Workplan and SOPO will succeed in meeting the project goals.

Identification of Risks

- Discussion and demonstrated understanding of the key anticipated risks (e.g., technical, financial, market, environmental, regulatory) involved in the proposed work and the quality of the mitigation strategies to address them.

Baseline, Metrics, and Deliverables

- The level of clarity in the definition of the baseline, metrics, and milestones.
- Relative to a clearly defined baseline, the strength of the quantifiable metrics, milestones, and mid-point deliverables defined in the application, such that meaningful interim progress will be made.

Project Financial Feasibility

- The reasonableness of the budget and spend plan for the proposed project and objectives.
- Soundness of proposed cost share; level of dedication as demonstrated by letter(s) of commitment that clearly identify type and amount of proposed cost share. Proposed cost share meets requirements outlined in the FOA.
- The degree to which the proposed project yields additive benefit(s) from the federal funding to undertake additional efforts that would not be taken but-for the funding or to accelerate or expand planned activities that would not be accelerated or expanded but-for the funding.
- The degree to which the applicant justifies the project's economic viability.
- The degree to which the project provides enhanced system value and/or provides improved current and future system cost-effectiveness and delivers economic benefit.

Project Viability, Readiness, and Timing

- Evidence to support the state of project planning, development, including depth, stage and degree of completeness of engineering design; status of critical agreements and permits; customer expressions of interest; and financial commitments beyond the support sought under this FOA.

Criterion 3 for Topic Area 3: Management Team and Project Partners (10%)
This criterion involves consideration of the following factors:

Project Management

- Clarity and appropriateness of the roles and responsibilities of the project management organization and the project team, including relevant and critical subrecipients and vendors.
- The capability of the Project Manager(s) and the proposed team to manage and address all aspects of the proposed work with a high probability of success.
- The qualifications, relevant expertise, and time commitment of the key individuals on project team.
- The level of participation by project participants as evidenced by letter(s) of commitment and how well they are integrated into the Project Plan/Workplan.
- The degree to which the applicant has defined and described a project management structure that addresses interfaces with DOE.

Partners

- Degree to which the applicant includes partnerships with critical entities that will help ensure project success, as well as any partnerships with entities (including other states) outside of the applicant's jurisdiction, who will commit to encourage asset operators (e.g., utilities, merchant developers) to replicate the proposed approaches, technologies or solutions, as applicable.

Criterion 4 for Topic Area 3: Community Benefits Plan (20%)
Every BIL-funded project is expected to contribute to the country's energy infrastructure modernization goals, energy technology demonstration and deployment goals, and climate goals, and also to (1) support meaningful community and labor engagement; (2) support quality jobs and ensure workforce continuity; (3) advance diversity, equity, inclusion, and accessibility; and (4) contribute to the Justice40 Initiative's goal that 40% of the overall project benefits flow to disadvantaged communities.

To ensure these goals are met, applications must include a Community Benefits Plan that illustrates how the proposed project plans to incorporate the four goals stated above and are encouraged to submit Community Partnership Documentation from established labor unions, Tribal entities, and community-based organizations that demonstrate the applicant's ability to achieve the above goals as outlined in the Community Benefits Plan.

This criterion involves consideration of the following factors:

Community and Labor Engagement

- Extent to which the applicant demonstrates community and labor engagement to date that results in support for the proposed project.
- Extent to which the applicant has a clear and appropriately robust plan to engage—ideally through a clear commitment to negotiate an enforceable Workforce & Community Agreements--with labor unions, Tribal entities, and community-based organizations that support or work with disadvantaged communities and other affected stakeholders.
- Extent to which the applicant has considered accountability to affected workers and community stakeholders, including those most vulnerable to project activities with a plan to publicly share SMART community benefits plan commitments.
- Extent to which the applicant demonstrates that community and labor engagement will lead to the delivery of high-quality jobs, minimal environmental impact, and allocation of project benefits to disadvantaged communities.

Quality Jobs

- Quality and manner in which the proposed project will create and/or retain high quality, good-paying jobs with employer-sponsored benefits for all classifications and phases of work.
- Extent to which the project provides employees with the ability to organize, bargain collectively, and participate, through labor organizations of their choosing, in decisions that affect them and that contribute to the effective conduct of business and facilitates amicable settlements of any potential disputes between employees and employers, providing assurances of project efficiency, continuity, and multiple public benefits.
- Extent to which applicant demonstrates that they are a responsible employer, with ready access to a sufficient supply of appropriately skilled labor, and an effective plan to minimize the risk of labor disputes or disruptions.

Diversity, Equity, Inclusion, and Accessibility (DEIA)

- The quality and manner in which the proposed project incorporates and measures diversity, equity, inclusion and accessibility goals in the project, as reflected in the applicant's Community Benefits Plan.
- Extent to which the project supports the development or demonstration in disadvantaged communities, supports existing minority business enterprises (MBEs) or promotes the creation of MBEs and underrepresented businesses in disadvantaged communities.
- Quality of any partnerships and agreements with apprenticeship readiness programs, or community-based workforce training and support organizations serving workers facing systematic barriers to employment to facilitate participation in the project's construction and operations.
- Extent of engagement of organizations that represent underserved communities as core element of their mission to include Minority Serving Institutions (MSIs), MBEs, associations, and non-profit organizations.
- Extent to which the project illustrates the ability to meet or exceed the objectives of the Justice40 initiative, including the extent to which the project benefits disadvantaged, underserved communities or partners with Tribal Nations.

Justice40 Initiative

- Extent to which the Community Benefits Plan identifies: specific, measurable benefits for disadvantaged communities, how the benefits will flow to disadvantaged communities, and how negative environmental impacts affecting disadvantaged communities would be mitigated.
- Extent to which the project would contribute to meeting the objective that 40% of the benefits of climate and clean energy investments flow to disadvantaged communities.

B. Standards for Application Evaluation

Applications that are determined to be eligible will be evaluated in accordance with this FOA and the guidance provided in the "DOE Merit Review Guide for Financial Assistance," effective September 2020, which is available at: https://energy.gov/management/downloads/merit-review-guide-financial-assistance-and-unsolicited-proposals-current.

C. Other Selection Factors

i. Program Policy Factors

In addition to the above criteria, the Selection Official may consider the following program policy factors in determining which Full Applications to select for award negotiations:

- The degree to which the proposed project exhibits technological diversity when compared to the existing DOE project portfolio and other projects selected from the subject FOA;
- The degree to which the proposed project, including proposed cost share, optimizes the use of available DOE funding to achieve programmatic objectives;
- The degree to which the proposed project will deliver the greatest benefits for less Federal cost share;
- The level of industry involvement and demonstrated ability to accelerate commercialization and overcome key market barriers;
- For Topic Area 1, the degree to which the applicant supports the availability of information before during and after resilience events through participation in the Outage Data Initiative Nationwide (ODIN),[52] a voluntary program to promote increasing standardization of outage data, accessible and achievable by any size utility;
- The degree to which the proposed project is likely to lead to increased high-quality employment and manufacturing in the United States;
- The degree to which the proposed project will accelerate transformational technological advances in areas that industry by itself is not likely to undertake because of technical and financial uncertainty;
- The degree to which the proposed project, or group of projects, represent a desired geographic distribution (considering past awards and current applications), including whether the project is in a community facing job loss in the energy transition;
- The degree to which the proposed project incorporates diversity, equity, and inclusion elements, including, but not limited to, applicant or team members from Minority Serving Institutions (e.g. Historically Black Colleges and Universities (HBCUs)/Other Minority Institutions), Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses, Veteran Owned Businesses, Tribal Nations, or members within underserved communities;
- The degree to which the proposed project maximizes benefits to disadvantaged communities;
- The degree to which the proposed project minimizes environmental impacts to disadvantaged communities;
- The degree to which the project's solution or strategy will maximize deployment or replication;
- The degree to which the proposed project leverages existing infrastructure, facilities, and/or workforce skills;
- The degree to which the proposed project will employ procurement of U.S. iron, steel, manufactured products, and construction materials;

[52] More information is available at odin.ornl.gov

- The degree to which the proposed project, when compared to the existing DOE project portfolio and other projects to be selected from the subject FOA, contributes to the total portfolio meeting the goals reflected in the Community Benefits Plan criteria;
- The degree to which the proposed project avoids duplication/overlap with other publicly or privately funded work.

D. Evaluation and Selection Process

i. Overview

The evaluation process consists of multiple phases; each includes an initial eligibility review and a thorough technical merit review. Rigorous technical merit reviews of eligible submissions are conducted by reviewers that are experts in the subject matter of the FOA. Ultimately, the Selection Official considers the recommendations of the reviewers, along with other considerations such as program policy factors, in determining which applications to select.

ii. Pre-Selection Interviews

As part of the evaluation and selection process, DOE may invite one or more applicants to participate in Pre-Selection Interviews. Pre-Selection Interviews are distinct from and more formal than pre-selection clarifications (See Section V.D.ii. of the FOA). The invited applicant(s) will meet with DOE representatives to provide clarification on the contents of the Full Applications and to provide DOE an opportunity to ask questions regarding the proposed project. The information provided by applicants to DOE through Pre-Selection Interviews contributes to DOE's selection decisions.

DOE will arrange to meet with the invited applicants in person at DOE's offices or a mutually agreed upon location. DOE may also arrange site visits at certain applicants' facilities. In the alternative, DOE may invite certain applicants to participate in a one-on-one conference with DOE via webinar, videoconference, or conference call.

DOE will not reimburse applicants for travel and other expenses relating to the Pre-Selection Interviews, nor will these costs be eligible for reimbursement as pre-award costs.

DOE may obtain additional information through Pre-Selection Interviews that will be used to make a final selection determination. DOE may select applications for funding and make awards without Pre-Selection Interviews. Participation in Pre-Selection Interviews with DOE does not signify that applicants have been selected for award negotiations.

iii. Pre-Selection Clarification

DOE may determine that pre-selection clarifications are necessary from one or more applicants. Pre-selection clarifications are distinct from and less formal than pre-selection interviews. These pre-selection clarifications will solely be for the purposes of clarifying the application. The pre-selection clarifications may occur before, during or after the merit review evaluation process. Information provided by an applicant that is not necessary to address the pre-selection clarification question will not be reviewed or considered. Typically, a pre-selection clarification will be carried out through either written responses to DOE's written clarification questions or video or conference calls with DOE representatives.

The information provided by applicants to DOE through pre-selection clarifications is incorporated in their applications and contributes to the merit review evaluation and DOE's selection decisions. If DOE contacts an applicant for pre-selection clarification purposes, it does not signify that the applicant has been selected for negotiation of award or that the applicant is among the top ranked applications.

DOE will not reimburse applicants for expenses relating to the pre-selection clarifications, nor will these costs be eligible for reimbursement as pre-award costs.

iv. Recipient Integrity and Performance Matters

DOE, prior to making a federal award with a total amount of federal share greater than the simplified acquisition threshold, is required to review and consider any information about the applicant that is in the designated integrity and performance system accessible through SAM (currently FAPIIS) (see 41 U.S.C. 2313).

The applicant, at its option, may review information in the designated integrity and performance systems accessible through SAM and comment on any information about itself that a federal awarding agency previously entered and is currently in the designated integrity and performance system accessible through SAM.

DOE will consider any written comments by the applicant, in addition to the other information in the designated integrity and performance system, in making a judgment about the applicant's integrity, business ethics, and record of performance under federal awards when completing the review of risk posed by applicants as described in 2 CFR 200.206.

v. Selection

The Selection Official may consider the technical merit, the Federal Consensus Board's recommendations, program policy factors, and the amount of funds available in arriving at selections for this FOA.

E. Anticipated Notice of Selection and Award Negotiation Dates

DOE anticipates notifying applicants selected for negotiation of award and negotiating awards by the dates provided on the cover page of this FOA.

VI. Award Administration Information

A. Award Notices

i. Ineligible Submissions

Ineligible Concept Papers and Full Applications will not be further reviewed or considered for award. The Contracting Officer will send a notification letter by email to the technical and administrative points of contact designated by the applicant The notification letter will state the basis upon which the Concept Paper or the Full Application is ineligible and not considered for further review.

ii. Concept Paper Notifications

DOE will notify applicants of its determination to encourage or discourage the submission of a Full Application. DOE will send a notification letter by email to the technical and administrative points of contact designated by the applicant in on the Concept Paper cover page.

Applicants may submit a Full Application even if they receive a notification discouraging them from doing so. By discouraging the submission of a Full Application, DOE intends to convey its lack of programmatic interest in the proposed project. Such assessments do not necessarily reflect judgments on the merits of the proposed project. The purpose of the Concept Paper phase is to save applicants the considerable time and expense of preparing a Full Application that is unlikely to be selected for award negotiations.

A notification encouraging the submission of a Full Application does not authorize the applicant to commence performance of the project. Please refer to Section IV.I.ii. of the FOA for guidance on pre-award costs.

iii. Full Application Notifications

DOE will notify applicants of its determination via a notification letter by email to the technical and administrative points of contact designated by the applicant in Grants.gov. The notification letter will inform the applicant whether or not its Full Application was selected for award negotiations. Alternatively, DOE may notify one or more applicants that a final selection determination on particular Full Applications will be made at a later date, subject to the availability of funds or other factors.

iv. Successful Applicants

Receipt of a notification letter selecting a Full Application for award negotiations does not authorize the applicant to commence performance of the project. If an application is selected for award negotiations, it is not a commitment by DOE to issue an award. Applicants do not receive an award until award negotiations are complete and the Contracting Officer executes the funding agreement, accessible by the prime recipient in FedConnect.

The award negotiation process will take approximately 60 days. Applicants must designate a primary and a backup point-of-contact in Grants.gov with whom DOE will communicate to conduct award negotiations. The applicant must be responsive during award negotiations (i.e., provide requested documentation) and meet the negotiation deadlines. If the applicant fails to do so or if award negotiations are otherwise unsuccessful, DOE will cancel the award negotiations and rescind the Selection. DOE reserves the right to terminate award negotiations at any time for any reason.

Please refer to Section IV.I.ii. of the FOA for guidance on pre-award costs.

v. Alternate Selection Determinations

In some instances, an applicant may receive a notification that its application was not selected for award and DOE designated the application to be an alternate. As an alternate, DOE may consider the Full Application for federal funding in the future. A notification letter stating the Full Application is designated as an alternate does not authorize the applicant to commence performance of the project. DOE may ultimately determine to select or not select the Full Application for award negotiations.

vi. Unsuccessful Applicants

DOE shall promptly notify in writing each applicant whose application has not been selected for award or whose application cannot be funded because of the unavailability of appropriated funds.

B. Administrative and National Policy Requirements

i. Registration Requirements

There are several one-time actions before submitting an application in response to this FOA, and it is vital that applicants address these items as soon as possible. Some may take several weeks, and failure to complete them could interfere with an applicant's ability to apply to this FOA, or to meet the negotiation deadlines and receive an award if the application is selected. These requirements are as follows:

1. **System for Award Management**
   Register with the SAM at https://www.sam.gov. Designating an Electronic Business Point of Contact (EBiz POC) and obtaining a special password called a Marketing Partner ID Number (MPIN) are important steps in SAM registration. Please update your SAM registration annually.

2. **FedConnect**
   Register in FedConnect at https://www.fedconnect.net. To create an organization account, your organization's SAM MPIN is required. For more information about the SAM MPIN or other registration requirements, review the FedConnect Ready, Set, Go! Guide at https://www.fedconnect.net/FedConnect/Marketing/Documents/FedConnect_Ready_Set_Go.pdf.

3. **Grants.gov**
   Register in Grants.gov (https://www.grants.gov/)) to receive automatic updates when Amendments to this FOA are posted. However, please note that Concept Papers will not be accepted through Grants.gov.

4. **Electronic Authorization of Applications and Award Documents**
   Submission of an application and supplemental information under this FOA through electronic systems used by the DOE, including Grants.gov and FedConnect.net, constitutes the authorized representative's approval and electronic signature.

ii. Award Administrative Requirements

The administrative requirements for DOE grants and cooperative agreements are contained in 2 CFR Part 200 as amended by 2 CFR Part 910.

iii. Foreign National Participation (September 2021)

All applicants selected for an award under this FOA and project participants (including subrecipients and contractors) who anticipate involving foreign nationals in the performance of an award, will be required to provide DOE with specific information about each foreign national to satisfy requirements for foreign national participation. A "foreign national" is defined as any person who is not a United States citizen by birth or naturalization. The volume and type of information collected may depend on various factors associated with the award. DOE concurrence may be required before a foreign national can participate in the performance of any work under an award.

Approval for foreign nationals from countries identified on the U.S. Department of State's list of State Sponsors of Terrorism must be obtained from DOE before they can participate in the performance of any work under an award.

iv. Subaward and Executive Reporting

Additional administrative requirements necessary for DOE grants and cooperative agreements to comply with the Federal Funding and Transparency Act of 2006 (FFATA) are contained in 2 CFR Part 170. Prime recipients must register with the new FFATA Subaward Reporting System database and report the required data on their first tier subrecipients. Prime recipients must report the executive compensation for their own executives as part of their registration profile in SAM.

v. National Policy Requirements

The National Policy Assurances that are incorporated as a term and condition of award are located at: http://www.nsf.gov/awards/managing/rtc.jsp.

vi. Environmental Review in Accordance with National Environmental Policy Act (NEPA)

DOE's decision whether and how to distribute federal funds under this FOA is subject to NEPA (42 U.S.C. 4321, *et seq.*). NEPA requires federal agencies to integrate environmental values into their decision-making processes by considering the potential environmental impacts of their proposed actions. For additional background on NEPA, please see DOE's NEPA website, at https://www.energy.gov/nepa.

While NEPA compliance is a federal agency responsibility and the ultimate decisions remain with the federal agency, all recipients selected for an award will be required to assist in the timely and effective completion of the NEPA process in the manner most pertinent to their proposed project. If DOE determines certain records must be prepared to complete the NEPA review process (e.g., biological evaluations or environmental assessments), the recipient may be required to prepare the records and the costs to prepare the necessary records may be included as part of the project costs.

vii. Flood Resilience

Applications should indicate whether the proposed project location(s) is within a floodplain, how the floodplain was defined, and how future flooding will factor into the project's design. The base floodplain long used for planning has been the 100-year floodplain, that is, a floodplain with a 1.0 percent chance of flooding in any given year. As directed by Executive Order 13690, Establishing a Federal Flood Risk Management Standard and a Process for Further Soliciting and Considering Stakeholder Input (2015), Federal agencies, including DOE, continue to avoid development in a floodplain to the extent possible. When doing so is not possible, Federal agencies are directed to "expand management from the current base flood level to a higher vertical elevation and corresponding horizontal floodplain to address current and future flood risk and ensure that projects funded with taxpayer dollars last as long as intended." The higher flood elevation is based on one of three approaches: climate-informed science (preferred), freeboard value, or 0.2 percent annual flood change (500-year floodplain). EO 13690 and related information is available at https://www.energy.gov/nepa/articles/eo-13690-establishing-federal-flood-risk-management-standard-and-process-further.

viii. Applicant Representations and Certifications

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

2. **Corporate Felony Conviction and Federal Tax Liability Representations**
   In submitting an application in response to this FOA, the applicant represents that:

   a. It is **not** a corporation that has been convicted of a felony criminal violation under any federal law within the preceding 24 months; and

   b. It is **not** a corporation that has any unpaid federal tax liability that has been assessed, for which all judicial and administrative remedies have been exhausted or have lapsed, and that is not being paid in a timely manner pursuant to an agreement with the authority responsible for collecting the tax liability.

   For purposes of these representations the following definitions apply:

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

3. **Nondisclosure and Confidentiality Agreements Representations**
   In submitting an application in response to this FOA the applicant represents that:

   a. It **does not and will not** require its employees or contractors to sign internal nondisclosure or confidentiality agreements or statements prohibiting or otherwise restricting its employees or contactors from lawfully reporting waste, fraud, or abuse to a designated investigative or law enforcement representative of a federal department or agency authorized to receive such information.

   b. It **does not and will not** use any federal funds to implement or enforce any nondisclosure and/or confidentiality policy, form, or agreement it uses unless it contains the following provisions:

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

   (2) The limitation above shall not contravene requirements applicable to Standard Form 312 Classified Information Nondisclosure Agreement (https://fas.org/sgp/othergov/sf312.pdf), Form 4414 Sensitive Compartmented Information Disclosure Agreement (https://fas.org/sgp/othergov/intel/sf4414.pdf), or any other form issued by a federal department or agency governing the nondisclosure of classified information.

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

ix. Statement of Federal Stewardship

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

x. Statement of Substantial Involvement (Applies to Topic Area 3 ONLY)

DOE has substantial involvement in work performed under awards made as a result of this FOA. DOE does not limit its involvement to the administrative requirements of the award. Instead, DOE has substantial involvement in the direction and redirection of the technical aspects of the project as a whole. Substantial involvement includes, but is not limited to, the following:

1. DOE shares responsibility with the recipient for the management, control, direction, and performance of the project.

2. DOE may intervene in the conduct or performance of work under this award for programmatic reasons. Intervention includes the interruption or modification of the conduct or performance of project activities.

3. DOE may redirect or discontinue funding the project based on the outcome of DOE's evaluation of the project at the Go/No-Go decision point(s) as identified in the Project Management Plan.

4. Reviewing and concurring with ongoing technical performance to ensure that adequate progress has been obtained within the current Budget Period authorized by DOE before work can commence on subsequent Budget Periods.

5. DOE participates in major project decision-making processes.

xi. Intellectual Property Management Plan (IPMP)

As a quarter 1 milestone if selected for award, applicants must submit an executed IPMP between the members of the consortia or team.

The award will set forth the treatment of and obligations related to intellectual property rights between DOE and the individual members. The IPMP should describe how the members will handle intellectual property rights and issues between themselves while ensuring compliance with federal intellectual property laws, regulations, and policies (see Sections VIII.J.-VIII.N. of this FOA for more details on applicable federal intellectual property laws and regulations). Guidance regarding the contents of IPMP is available from DOE upon request.

The following is a non-exhaustive list of examples of items that the IPMP may cover:

- The treatment of confidential information between members (e.g., the use of NDAs);
- The treatment of background intellectual property (e.g., any requirements for identifying it or making it available);
- The treatment of inventions made under the award (e.g., any requirements for disclosing to the other members on an application, filing patent applications, paying for patent prosecution, and cross-licensing or other licensing arrangements between the members);
- The treatment of data produced, including software, under the award (e.g., any publication process or other dissemination strategies, copyrighting strategy or arrangement between members);
- Any technology transfer and commercialization requirements or arrangements between the members;
- The treatment of any intellectual property issues that may arise due to a change in membership of the consortia or team; and
- The handling of disputes related to intellectual property between the members.

xii. Intellectual Property Provisions

The standard DOE financial assistance intellectual property provisions applicable to the various types of recipients are located at http://energy.gov/gc/standard-intellectual-property-ip-provisions-financial-assistance-awards.

xiii. Reporting

Reporting requirements are identified on the Federal Assistance Reporting Checklist and Instructions, DOE F 4600.2, attached to the award agreement. A sample checklist is available at: BIL-GRIP Application Forms and Templates | netl.doe.gov.

Additional reporting requirements apply to projects funded by BIL. As part of tracking progress toward key departmental goals – ensuring justice and equity, investing in the American workforce, boosting domestic manufacturing, reducing greenhouse gas emissions, and advancing a pathway to private sector deployment – DOE may require specific data collection. Examples of data that may be collected include:

- New manufacturing production, and recycling capacity
- Jobs data including
- Number and types of training jobs provided, wages and benefits paid
- Demographics of workforce including local hires
- Efforts to minimize risks of labor disputes and disruptions
- Contributions to training; certificates and training credentials received by employees; ratio of apprentice-to-journey level workers employed
- Justice and Equity data, including
    - Minority Business Enterprises, Minority Owned Businesses, Woman Owned Businesses and Veteran Owned Businesses acting as vendors and sub-contractors for bids on supplies, services and equipment.
    - Value, number, and type of partnerships with MSIs
    - Stakeholder engagement events, consent-based siting activities
    - Other relevant indicators from the Community Benefits Plan
- Number and type of energy efficient and clean energy equipment installed
- Funding leveraged, follow-on-funding, Intellectual Property (IP) Generation and IP Utilization
- Biennial Report to Congress - (Applies to Topic Area 1 ONLY), See Section I.B. for more information.

xiv. Go/No-Go Review

Each project selected under this FOA will be subject to a periodic project evaluation referred to as a Go/No-Go Review. A Go/No-Go Review is a risk management tool and a project management best practice to ensure that, for the current phase or period of performance, technical success is definitively achieved and potential for success in future phases or periods of performance is evaluated, prior to actually beginning the execution of future phases. At the Go/No-Go decision points, DOE will evaluate project performance, project schedule adherence, the extent milestone objectives are met, compliance with reporting requirements, and overall contribution to the program goals and objectives. Federal funding beyond the Go/No-Go decision point (continuation funding) is contingent upon (1) availability of federal funds appropriated by Congress for the purpose of this program; (2) the availability of future-year budget authority; (3) recipient's technical progress as compared to the technical milestones, success criteria, and go/no-go decision point as described in the Project Management Plan; (4) recipient's submittal of required reports; (5) recipient's compliance with the terms and conditions of the award; (6) the recipient's submission of a continuation application[53]; and (7) written approval of the continuation application by the Contracting Officer.

As a result of the Go/No-Go Review, DOE may, at its discretion, authorize the following actions: (1) continue to fund the project, contingent upon the availability of funds appropriated by Congress for the purpose of this program and the availability of future-year budget authority; (2) recommend redirection of work under the project; (3) place a hold on federal funding for the project, pending further supporting data or funding; or (4) discontinue funding the project because of insufficient progress, change in strategic direction, or lack of funding.

The Go/No-Go decision is distinct from a non-compliance determination. In the event a recipient fails to comply with the requirements of an award, DOE may take appropriate action, including but not limited to, redirecting, suspending or terminating the award.

xv. Conference Spending

The recipient shall not expend any funds on a conference not directly and programmatically related to the purpose for which the grant or cooperative agreement was awarded that would defray the cost to the United States government of a conference held by any Executive branch department, agency, board, commission, or office for which the cost to the United States government would otherwise exceed $20,000, thereby circumventing the required

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[53] A continuation application is a non-competitive application for an additional budget period within a previously approved project period. At least ninety (90) days before the end of each budget period, the recipient must submit its continuation application, which includes the following information:

i. A progress report on the project objectives, including significant findings, conclusions, or developments, and an estimate of any unobligated balances remaining at the end of the budget period. If the remaining unobligated balance is estimated to exceed 20 percent of the funds available for the budget period, explain why the excess funds have not been obligated and how they will be used in the next budget period.

ii. A detailed budget and supporting justification if there are changes to the negotiated budget, or a budget for the upcoming budget period was not approved at the time of award.

iii. A description of any planned changes from the SOPO and/or Milestone Summary Table.

notification by the head of any such Executive Branch department, agency, board, commission, or office to the Inspector General (or senior ethics official for any entity without an Inspector General), of the date, location, and number of employees attending such conference.

xvi. Uniform Commercial Code (UCC) Financing Statements

Per 2 CFR 910.360 (Real Property and Equipment) when a piece of equipment is purchased by a for-profit recipient or subrecipient with federal funds, and when the federal share of the financial assistance agreement is more than $1,000,000, the recipient or subrecipient must:

Properly record, and consent to the Department's ability to properly record if the recipient fails to do so, UCC financing statement(s) for all equipment in excess of $5,000 purchased with project funds. These financing statement(s) must be approved in writing by the Contracting Officer prior to the recording, and they shall provide notice that the recipient's title to all equipment (not real property) purchased with federal funds under the financial assistance agreement is conditional pursuant to the terms of this section, and that the government retains an undivided reversionary interest in the equipment. The UCC financing statement(s) must be filed before the Contracting Officer may reimburse the recipient for the federal share of the equipment unless otherwise provided for in the relevant financial assistance agreement. The recipient shall further make any amendments to the financing statements or additional recordings, including appropriate continuation statements, as necessary or as the Contracting Officer may direct.

xvii. Implementation of Executive Order 13798, Promoting Free Speech and Religious Liberty

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

xviii. Participants and Collaborating Organizations

If selected for award negotiations, the selected applicant must submit a list of personnel who are proposed to work on the project, both at the recipient and subrecipient level and a list of collaborating organizations within 30 days after the applicant is notified of the selection. Recipients will have an ongoing responsibility to notify DOE of changes to the personnel and collaborating organizations and submit updated information during the life of the award.

xix. Requirement to Report Potentially Duplicative Funding

If a recipient or project team member receives any other award of federal funds for activities that potentially overlap with the activities funded under the DOE award, the recipient must promptly notify DOE in writing of the potential overlap and state whether project funds from any of those other federal awards have been, are being, or are to be used (in whole or in part) for one or more of the identical cost items under the DOE award. If there are identical cost items, the recipient must promptly notify the DOE Contracting Officer in writing of the potential duplication and eliminate any inappropriate duplication of funding. Also See Section IV.D.xvi.

xx. Interim Conflict of Interest Policy for Financial Assistance

The DOE interim Conflict of Interest Policy for Financial Assistance (COI Policy)[54] is applicable to all non-Federal entities applying for, or that receive, DOE funding by means of a financial assistance award (e.g., a grant, cooperative agreement, or technology investment agreement) and, through the implementation of this policy by the entity, to each senior/key personnel[55] who is planning to participate in, or is participating in, the project funded wholly or in part under the DOE financial assistance award. The term "senior/key personnel" means the Program/Project Manager and any other person, regardless of title or position, who is responsible for the purpose, design, conduct, or reporting of a project funded by DOE or proposed for funding by DOE. Recipients must flow down the requirements of the interim COI Policy to any subrecipient non-Federal entities. Further, for DOE funded projects, the recipient must include all financial conflicts of interest (FCOI) (i.e., managed and unmanaged/ unmanageable) in their initial and ongoing FCOI reports.

It is understood that non-Federal entities and individuals receiving DOE financial assistance awards will need sufficient time to come into full compliance with DOE's interim COI Policy. To provide some flexibility, DOE allows for a staggered implementation. **Specifically, prior to award, applicants selected for award negotiations must: ensure all senior/key personnel complete their significant financial disclosures; review the disclosures; determine whether a FCOI exists; develop and implement a management plan for FCOIs; and provide DOE with an initial FCOI report that includes all FCOIs (i.e., managed and unmanaged/ unmanageable).** Recipients will have 180 days from the date of the award to come into full compliance with the other requirements set forth in DOE's interim COI Policy. **Prior to award, the applicant must certify that it is, or will be within 180 days of the award, compliant with all requirements in the COI Policy.**

[54] DOE's interim COI Policy can be found at [PF 2022-17 FAL 2022-02 Department of Energy Interim Conflict of Interest Policy Requirements for Financial Assistance]().

[55] For purposes of this subsection of the FOA, the term "senior/key personnel" has the same meaning as "Investigator" as defined in the DOE interim COI Policy.

xxi. Fraud, Waste and Abuse

The mission of the DOE Office of Inspector General (OIG) is to strengthen the integrity, economy and efficiency of the Department's programs and operations including deterring and detecting fraud, waste, abuse and mismanagement. The OIG accomplishes this mission primarily through investigations, audits, and inspections of DOE activities to include grants, cooperative agreements, loans, and contracts.

The OIG maintains a Hotline for reporting allegations of fraud, waste, abuse, or mismanagement. To report such allegations, please visit https://www.energy.gov/ig/ig-hotline.

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

> The non-Federal entity or applicant for a Federal award must disclose, in a timely manner, in writing to the Federal awarding agency or pass-through entity all violations of Federal criminal law involving fraud, bribery, or gratuity violations potentially affecting the Federal award. Non-Federal entities that have received a Federal award including the term and condition outlined in appendix XII of 2 CFR Part 200 are required to report certain civil, criminal, or administrative proceedings to SAM (currently FAPIIS). Failure to make required disclosures can result in any of the remedies described in 2 CFR 200.339. (See also 2 CFR part 180, 31 U.S.C. 3321, and 41 U.S.C. 2313.) [85 FR 49539, Aug. 13, 2020]

xxii. Human Subjects Research

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

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

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

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

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

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

Additional information on the DOE Human Subjects Research Program can be found at: HUMAN SUBJECTS Human Subjects Pr... | U.S. DOE Office of Science (SC) (osti.gov).

xxiii. Cybersecurity Plan (Applies to Topic Areas 2 & 3 ONLY)

Be advised that under Section 40126 of the BIL, the Secretary of Energy has determined that this FOA requires an applicant to submit a Cybersecurity Plan to the DOE prior to the issuance of an award.

Each applicant whose Full Application is selected for award negotiations must submit a Cybersecurity Plan during the award negotiations phase. A Cybersecurity Plan explains how basic cybersecurity practices throughout the life of the proposed the project will be maintained. See Appendix E.

xxiv. Domestic Content Commitments

Be advised that the grant agreement or cooperative agreement for funding between DOE and the awardee will require each recipient: (1) to fulfill the commitments made in its application regarding the procurement of U.S.-produced products, subject to a waiver process by DOE and (2) to fulfill the commitments made in its application regarding the procurement of other key component metals and manufactured products domestically that are deemed available in sufficient and reasonably available quantities or of a satisfactory quality at the time of award negotiation, again subject to a DOE waiver process.

xxv. Real Property and Equipment

Property disposition will be required at the end of a project if the current fair market value of property exceeds $5,000. For-profit entity disposition requirements are set forth at 2 CFR 910.360. Property disposition requirements for other non-federal entities are set forth in 2 CFR 200.310 – 200.316.

Real property and equipment purchased with project funds (federal share and recipient cost share) are subject to the requirements at 2 CFR 200.310, 200.311, 200.313, and 200.316 (non-Federal entities, except for-profit entities) and 2 CFR 910.360 (for-profit entities). For projects selected for award under this FOA, the recipient may take disposition action on the real property and equipment or continue to use the real property and equipment after the conclusion of the award period of performance. Recipients may continue to use the real property and equipment so long as the recipient:

a. continues to use the property for the authorized project purposes;
b. complies with the applicable reporting requirements and regulatory property standards; and
c. requests continued use of the property with its final SF-428 Tangible Personal Property Report and/or SF-429 Real Property Status Report submission during award closeout.

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

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

VII. Questions/Agency Contacts

Upon the issuance of a FOA, DOE personnel are prohibited from communicating (in writing or otherwise) with applicants regarding the FOA except through the established question and answer process as described below. Specifically, questions regarding this FOA must be submitted through the FedConnect portal. You must register with FedConnect to respond as an interested party to submit questions. It is recommended that you register as soon after release of the FOA as possible to have the benefit of all responses. Applicants are encouraged to review previously issued Questions and Answers prior to the submission of questions.

Questions and comments concerning this FOA shall be submitted not later than 5 business days prior to the application due date. Please note, feedback on individual concepts will not be provided through Q&A.

All questions and answers related to this FOA will be posted on the FedConnect portal at: https://www.FedConnect.net and on the Grid Resilience and Innovation Partnerships (GRIP) Program web page at: Grid Resilience Innovation Partnership Programs | Department of Energy.

DOE will attempt to respond to a question within 3 business days unless a similar question and answer has already been posted on the website.

Questions relating to the registration process, system requirements, how an application form works, or the submittal process must be directed to Grants.gov at 1-800-518-4726 or support@grants.gov. DOE/NNSA cannot answer these questions.

VIII. Other Information

A. FOA Modifications

Amendments to this FOA will be posted on the Grants.gov system and the FedConnect portal. However, you will only receive an email when an amendment or a FOA is posted on these sites by registering with FedConnect as an interested party for this FOA. DOE recommends that you register as soon after the release of the FOA as possible to ensure you receive timely notice of any amendments or other FOAs.

B. Government Right to Reject or Negotiate

DOE reserves the right, without qualification, to reject any or all applications received in response to this FOA and to select any application, in whole or in part, as a basis for negotiation and/or award.

C. Commitment of Public Funds

The Contracting Officer is the only individual who can make awards or commit the government to the expenditure of public funds. A commitment by anyone other than the Contracting Officer, either express or implied, is invalid.

D. Treatment of Application Information

Applicants should not include business sensitive (e.g., commercial or financial information that is privileged or confidential), trade secrets, proprietary, or otherwise confidential in their application unless such information is necessary to convey an understanding of the proposed project or to comply with a requirement in the FOA. Applicants are advised to not include any critically sensitive proprietary detail.

If an application includes business sensitive, trade secrets, proprietary, or otherwise confidential information, it is furnished to the Federal Government (Government) in confidence with the understanding that the information shall be used or disclosed only for evaluation of the application. Such information will be withheld from public disclosure to the extent permitted by law, including the Freedom of Information Act. Without assuming any liability for inadvertent disclosure, DOE will seek to limit disclosure of such information to its employees and to outside reviewers when necessary for merit review of the application or as otherwise authorized by law. This restriction does not limit the Government's right to use the information if it is obtained from another source.

If an applicant chooses to submit business sensitive, trade secrets, proprietary, or otherwise confidential information, the applicant must provide **two copies** of the submission (e.g., Concept Paper, Full Application). The first copy should be marked, "non-confidential" with the information believed to be confidential deleted. The second copy should be marked "confidential" and must clearly and conspicuously identify the business sensitive, trade secrets, proprietary, or otherwise confidential information and must be marked as described below. Failure to comply with these marking requirements may result in the disclosure of the unmarked information under the Freedom of Information Act or otherwise. The Government is not liable for the disclosure or use of unmarked information and may use or disclose such information for any purpose.

The cover sheet of the Full Application, and other submission must be marked as follows and identify the specific pages business sensitive, trade secrets, proprietary, or otherwise confidential information:

> **Notice of Restriction on Disclosure and Use of Data:**
> Pages [list applicable pages] of this document may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source. [End of Notice]

In addition, (1) the header and footer of every page that contains business sensitive, trade secrets, proprietary, or otherwise confidential information must be marked as follows: "Contains Business Sensitive, Trade Secrets, Proprietary, or Otherwise Confidential Information Exempt from Public Disclosure," and (2) every line or paragraph containing such information must be clearly marked with double brackets or highlighting. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

E. Evaluation and Administration by Non-Federal Personnel

In conducting the technical merit review evaluation, the Go/No-Go Reviews and Peer Reviews, the government may seek the advice of qualified non-federal personnel as reviewers. The government may also use non-federal personnel to conduct routine, nondiscretionary administrative activities, including DOE contractors. The applicant, by submitting its application, consents to the use of non-federal reviewers/administrators. Non-federal reviewers must sign conflict of interest (COI) and non-disclosure acknowledgements (NDA) prior to reviewing an application. Non-federal personnel conducting administrative activities must sign an NDA.-federal personnel conducting administrative activities must sign an NDA.

F. Notice Regarding Eligible/Ineligible Activities

Eligible activities under this FOA include those which describe and promote the understanding of scientific and technical aspects of specific energy technologies, but not those which encourage or support political activities such as the collection and dissemination of information related to potential, planned or pending legislation.

G. Notice of Right to Conduct a Review of Financial Capability

DOE reserves the right to conduct an independent third-party review of financial capability for applicants that are selected for negotiation of award (including personal credit information of principal(s) of a small business if there is insufficient information to determine financial capability of the organization).).

H. Requirement for Full and Complete Disclosure

Applicants are required to make a full and complete disclosure of all information requested. Any failure to make a full and complete disclosure of the requested information may result in:

- The termination of award negotiations;
- The modification, suspension, and/or termination of a funding agreement;
- The initiation of debarment proceedings, debarment, and/or a declaration of ineligibility for receipt of federal contracts, subcontracts, and financial assistance and benefits; and
- Civil and/or criminal penalties.

I. Retention of Submissions

DOE expects to retain copies of all Full Applications and other submissions. No submissions will be returned. By applying to DOE for funding, applicants consent to DOE's retention of their submissions.

J. Rights in Technical Data

Data rights differ based on whether data is first produced under an award or instead was developed at private expense outside the award.

"Limited Rights Data": The U.S. government will not normally require delivery of confidential or trade secret-type technical data developed solely at private expense prior to issuance of an award, except as necessary to monitor technical progress and evaluate the potential of proposed technologies to reach specific technical and cost metrics.

Government Rights in Technical Data Produced Under Awards: The U.S. government normally retains unlimited rights in technical data produced under government financial assistance awards, including the right to distribute to the public. However, pursuant to special statutory authority, certain categories of data generated under DOE awards may be protected from public disclosure for up to five years after the data is generated ("Protected Data"). For awards permitting Protected Data, the protected data must be marked as set forth in the award's intellectual property terms and conditions and a listing of unlimited rights data (i.e., non-protected data) must be inserted into the data clause in the award. In addition, invention disclosures may be protected from public disclosure for a reasonable time in order to allow for filing a patent application.

For this FOA, selectees and recipients may request an extended period of protection (more than five years and not to exceed thirty years) if reasonably required for commercialization for specific categories of data for all Topic Areas first produced under the resulting awards in accordance with 15 U.S.C. § 3710a(c)(7)(B)(ii) and the Energy Policy Acts of 1992 and 2005. Further direction will be provided during the negotiation process upon request.

K. Copyright

The prime recipient and subrecipients may assert copyright in copyrightable works, such as software, first produced under the award without DOE approval. When copyright is asserted, the government retains a paid-up nonexclusive, irrevocable worldwide license to reproduce, prepare derivative works, distribute copies to the public, and to perform publicly and display publicly the copyrighted work. This license extends to contractors and others doing work on behalf of the government.

L. Export Control

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

The recipient must immediately report to DOE any export control violations related to the project funded under the DOE award, at the recipient or subrecipient level, and provide the corrective action(s) to prevent future violations.

M. Prohibition on Certain Telecommunications and Video Surveillance Services or Equipment

As set forth in 2 CFR 200.216, recipients and subrecipients are prohibited from obligating or expending project funds (federal funds and recipient cost share) to:

(1) Procure or obtain;

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

(3) Enter into a contract (or extend or renew a contract) to procure or obtain equipment, services, or systems that uses covered telecommunications equipment or services as a substantial or essential component of any system, or as critical technology as part of any system. As described in Public Law 115-232, section 889, covered telecommunications equipment is telecommunications equipment produced by Huawei Technologies Company or ZTE Corporation (or any subsidiary or affiliate of such entities). See Public Law 115-232, section 889, and 2 CFR 200.471 for additional information.

N. Personally Identifiable Information (PII)

All information provided by the applicant must to the greatest extent possible exclude PII. The term “PII” refers to information which can be used to distinguish or trace an individual's identity, such as their name, social security number, biometric records, alone, or when combined with other personal or identifying information which is linked or linkable to a specific individual, such as date and place of birth, mother’s maiden name. (See OMB Memorandum M-07-16 dated May 22, 2007, found at: M-07-16 (whitehouse.gov).

By way of example, applicants must screen resumes to ensure that they do not contain PII such as personal addresses, personal landline/cell phone numbers, and personal emails. **Under no circumstances should Social Security Numbers (SSNs) be included in the application**. Federal agencies are prohibited from the collecting, using, and displaying unnecessary SSNs. (See, the Federal Information Security Modernization Act of 2014 (Pub. L. No. 113-283, Dec 18, 2014; 44 U.S.C. § 3551).

O. Annual Independent Audits

If a for-profit entity is a prime recipient and has expended $750,000 or more of DOE awards during the entity's fiscal year, an annual compliance audit performed by an independent auditor is required. For additional information, please refer to 2 CFR 910.501 and Subpart F.

If an educational institution, non-profit organization, or state/local government is a prime recipient or subrecipient and has expended $750,000 or more of federal awards during the non-federal entity's fiscal year, then a Single or Program-Specific Audit is required. For additional information, please refer to 2 CFR 200.501 and Subpart F.

Applicants and subrecipients (if applicable) should propose sufficient costs in the project budget to cover the costs associated with the audit. DOE will share in the cost of the audit at its applicable cost share ratio.

P. Informational Webinars

Initial Webinar

DOE will conduct one informational webinar at the date and time listed in the table on the FOA cover page prior to concept paper submission due dates. The purpose of this webinar is to give applicants a chance to ask questions about the FOA process generally. As the webinar will be open to all Applicants who wish to participate, Applicants should refrain from asking questions or communicating information that would reveal confidential and/or proprietary information specific to their project.

Additional Webinars

Additional webinars are scheduled. See below for schedule and agenda information. Webinar registration information will be provided on the Grid Resilience and Innovation Partnerships (GRIP) Program web page at: Grid Resilience Innovation Partnership Programs | Department of Energy. Questions will not be taken as part of these webinars.

February 27 | 1-2 PM EST
Agenda
This webinar will cover information such as community and labor engagement, advancing Diversity Equity Inclusion and Accessibility, and the Justice40 initiative. As a prospective applicant to the FY 2022/2023 GRIP program, applicants will learn best practices for proposing meaningful Community Benefits Plans with tangible objectives to ensure the best community outcomes as part of these applications.

February 28 | 1-3 PM EST
Agenda
This webinar will provide industry stakeholders with cybersecurity planning to help prospective applicants enhance current efforts to improve the reliability, resiliency, and security of the U.S. power grid. Topics covered will include security risk evaluation, mitigation measures , and other security best practices from early development stages to implementation. The session will be conducted by our expert security team from DOE National Labs and provide training on cybersecurity planning and security best practices.

Attendance is not mandatory for the webinars and will not positively or negatively impact the overall review of any applicant submissions. Recordings of the webinars will be made available on the GRIP Program web page at: Grid Resilience Innovation Partnership Programs | Department of Energy.

APPENDIX A – COST SHARE INFORMATION

Cost Sharing or Cost Matching

The terms "cost sharing" and "cost matching" are often used synonymously. Even the DOE Financial Assistance Regulations, 2 CFR 200.306, use both of the terms in the titles specific to regulations applicable to cost sharing. The difference between the two terms is the calculation used to determine the non-federal amount. "Cost sharing" for the non-federal share is calculated as a percentage of the Total Project Cost. "Cost matching" for the non-federal share is calculated as a percentage of the federal funds only, rather than the Total Project Cost.

How Cost Sharing Is Calculated

As stated above, cost sharing is calculated as a percentage of the Total Project Cost. The following is an example of how to calculate cost sharing amounts for a project with $1,000,000 in federal funds with a minimum 20% non-federal cost sharing requirement:

- Formula A: Federal share ($) divided by federal share (%) = Total Project Cost ($)
  Example: $1,000,000 divided by 80% = $1,250,000

- Formula B: Total Project Cost ($) minus federal share ($) = Non-federal **share** ($)
  Example: $1,250,000 minus $1,000,000 = $250,000

- Formula C: Non-federal share ($) divided by Total Project Cost ($) = Non-federal **share** (%)
  Example: $250,000 divided by $1,250,000 = 20%

How Cost Matching Is Calculated

"Cost matching" for the non-federal share is calculated as a percentage of the Federal funds only, rather than the Total Project Cost. The following are examples of how to calculate cost matching amounts for a project with $1,000,000 in federal funds with a minimum 20% non-federal cost matching requirement:

- Formula D: Federal share ($) multiplied by non-federal share (%) = Non-federal **match** ($)
  Example: $1,000,000 multiplied by 20% = $200,000

- Formula E: Federal Share ($) plus Non-Federal Match ($) = Total Project Cost ($)
- Example: $1,000,000 plus $200,000 = $1,200,000

- Formula F: Total Project Cost ($) minus federal share ($) = Non-federal **match** ($)
  Example: $1,200,000 minus $1,000,000 = $200,000

- Formula G: Federal share ($) divided by Total Project Cost ($) = Calculated Federal Share of Total Project Cost (%)

  Example: $1,000,000 divided by $1,200,000 = 83.33%

- Formula C: Non-Federal share ($) divided by Total Project Cost ($) = Calculated Non-Federal Share of Total Project Cost (%)

  Example: $200,000 divided by $1,200,000 = 16.67%

The tables below provide additional examples of calculation results for the cost match (Topic Area 1) and cost share (Topic Areas 2 and 3) for the three BIL Topic Areas:

Topic Area 1: Section 40101 (c) Grid Resilience Grants ($100M Maximum Grant (Federal Share $).
An eligible entity shall be required to match 100% of the amount of the grant (except for Small Utilities must match 1/3 of the grant).

Maximum Federal Share ($)	Entity Type	Non-Federal Minimum Match Required (%)	Calculated Non-Federal Mininum Match ($)[D]	Total Project Cost ($)[E]	Calculated Federal Share of Total Project Costs (%)[G]	Calculated Non-Federal Share of Total Project Costs (%)[c]
$100,000,000	Eligible Entity (except for Small Utilities)	100	$100,000,000	$200,000,000	50	50
$100,000,000	Small Utility	33.33	$33,330,000	$133,330,000	75	25

Topic Area 2: Section 40107 Smart Grid Grants ($50M Maximum Grant (Federal Share $).
The non-federal cost share must be at least 50% of the Total Project Costs.

Maximum Federal Share ($)	Entity Type	Non-Federal Cost Share Minimum % of Total Project Costs (%)	Calculated Non-Federal Mininum Share ($)[B]	Total Project Cost ($)[A]	Calculated Non-Federal Mininum Share (%)[C]
$50,000,000	Eligible Entity	50	$50,000,000	$100,000,000	50

Topic Area 3: SECTION 40103 (b) Innovative Grid Resilience Program Example breakdown for $250M and $1B maximum Grant (Federal Share $) The non-federal cost share must be at least 50% of the Total Project Costs.					
Federal Share ($)	**Entity Type**	**Non-Federal Cost Share Minimum % of Total Project Costs (%)**	**Calculated Non-Federal Mininum Share ($)[B]**	**Total Project Cost ($)[A]**	**Calculated Non-Federal Mininum Share (%)[C]**
$250,000,000	Eligible Entity	50	$250,000,000	$500,000,000	50
$1,000,000,000	Eligible Entity	50	$1,000,000,000	$2,000,000,000	50

What Qualifies For Cost Sharing?

While it is not possible to explain what specifically qualifies for cost sharing in one or even a couple of sentences, in general, if a cost is allowable under the cost principles applicable to the organization incurring the cost and is eligible for reimbursement under a DOE grant or cooperative agreement, then it is allowable as cost share. Conversely, if the cost is not allowable under the cost principles and not eligible for reimbursement, then it is not allowable as cost share. In addition, costs may not be counted as cost share if they are paid by the federal government under another award unless authorized by federal statute to be used for cost sharing.

The rules associated with what is allowable as cost share are specific to the type of organization that is receiving funds under the grant or cooperative agreement, though are generally the same for all types of entities. The specific rules applicable to:

- FAR Part 31 for For-Profit entities, (48 CFR Part 31); and
- 2 CFR Part 200 Subpart E - Cost Principles for all other non-federal entities.

In addition to the regulations referenced above, other factors may also come into play such as timing of donations and length of the project period. For example, the value of ten years of donated maintenance on a project that has a project period of five years would not be fully allowable as cost share. Only the value for the five years of donated maintenance that corresponds to the project period is allowable and may be counted as cost share.

Additionally, DOE generally does not allow pre-award costs for either cost share or reimbursement when these costs precede the signing of the appropriation bill that funds the award. In the case of a competitive award, DOE generally does not allow pre-award costs prior to the signing of the Selection Statement by the DOE Selection Official.

General Cost Sharing Rules on a DOE Award

1. Cash Cost Share – encompasses all contributions to the project made by the recipient or subrecipient(s), for costs incurred and paid for during the project. This includes when an organization pays for personnel, supplies, equipment for their own company with organizational resources. If the item or service is reimbursed for, it is cash cost share. All cost share items must be necessary to the performance of the project.

2. In-Kind Cost Share – encompasses all contributions to the project made by the recipient or subrecipient(s) that do not involve a payment or reimbursement and represent donated items or services. In-Kind cost share items include volunteer personnel hours, donated existing equipment, donated existing supplies. The cash value and calculations thereof for all In-Kind cost share items must be justified and explained in the Cost Share section of the project Budget Justification. All cost share items must be necessary to the performance of the project. If questions exist, consult your DOE contact before filling out the In-Kind cost share section of the Budget Justification.

3. Funds from other federal sources MAY NOT be counted as cost share. Non-federal sources include any source not originally derived from federal funds. Cost sharing commitment letters from subrecipients must be provided with the original application.

4. Fee or profit, including foregone fee or profit, are not allowable as project costs (including cost share) under any resulting award. The project may only incur those costs that are allowable and allocable to the project (including cost share) as determined in accordance with the applicable cost principles prescribed in FAR Part 31 for For-Profit entities and 2 CFR Part 200 Subpart E - Cost Principles for all other non-federal entities.

DOE Financial Assistance Rules 2 CFR Part 200 as amended by 2 CFR Part 910

As stated above, the rules associated with what is allowable cost share are generally the same for all types of organizations. Following are the rules found to be common, but again, the specifics are contained in the regulations and cost principles specific to the type of entity:

(A) Acceptable contributions. All contributions, including cash contributions and third-party in-kind contributions, must be accepted as part of the prime recipient's cost sharing if such contributions meet all of the following criteria:

- **(1)** They are verifiable from the recipient's records.

- **(2)** They are not included as contributions for any other federally-assisted project or program.

- **(3)** They are necessary and reasonable for the proper and efficient accomplishment of project or program objectives.

(4) They are allowable under the cost principles applicable to the type of entity incurring the cost as follows:

a. For-profit organizations. Allowability of costs incurred by for-profit organizations and those nonprofit organizations listed in Attachment C to OMB Circular A–122 is determined in accordance with the for-profit cost principles in 48 CFR Part 31 in the FAR, except that patent prosecution costs are not allowable unless specifically authorized in the award document. (v) Commercial Organizations. FAR Subpart 31.2—Contracts with Commercial Organizations; and

b. Other types of organizations. For all other non-federal entities, allowability of costs is determined in accordance with 2 CFR Part 200 Subpart E.

(5) They are not paid by the federal government under another award unless authorized by federal statute to be used for cost sharing or matching.

(6) They are provided for in the approved budget.

(B) Valuing and documenting contributions

(1) Valuing recipient's property or services of recipient's employees. Values are established in accordance with the applicable cost principles, which mean that amounts chargeable to the project are determined on the basis of costs incurred. For real property or equipment used on the project, the cost principles authorize depreciation or use charges. The full value of the item may be applied when the item will be consumed in the performance of the award or fully depreciated by the end of the award. In cases where the full value of a donated capital asset is to be applied as cost sharing or matching, that full value must be the lesser or the following:

a. The certified value of the remaining life of the property recorded in the recipient's accounting records at the time of donation; or
b. The current fair market value. If there is sufficient justification, the Contracting Officer may approve the use of the current fair market value of the donated property, even if it exceeds the certified value at the time of donation to the project. The Contracting Officer may accept the use of any reasonable basis for determining the fair market value of the property.

(2) Valuing services of others' employees. If an employer other than the recipient furnishes the services of an employee, those services are valued at the employee's regular rate of pay, provided these services are for the same skill level for which the employee is normally paid.

(3) Valuing volunteer services. Volunteer services furnished by professional and technical personnel, consultants, and other skilled and unskilled labor may be counted as cost sharing or matching if the service is an integral and necessary part of an approved project or program. Rates for volunteer services must be consistent with those paid for similar work in the recipient's organization. In those markets in which the required skills are not found in the recipient organization, rates must be consistent with those paid for similar work in the labor market in which the recipient competes for the kind of services involved. In either case, paid fringe benefits that are reasonable, allowable, and allocable may be included in the valuation.

(4) Valuing property donated by third parties.

a. Donated supplies may include such items as office supplies or laboratory supplies. Value assessed to donated supplies included in the cost sharing or matching share must be reasonable and must not exceed the fair market value of the property at the time of the donation.

b. Normally only depreciation or use charges for equipment and buildings may be applied. However, the fair rental charges for land and the full value of equipment or other capital assets may be allowed, when they will be consumed in the performance of the award or fully depreciated by the end of the award, provided that the Contracting Officer has approved the charges. When use charges are applied, values must be determined in accordance with the usual accounting policies of the recipient, with the following qualifications:

i. The value of donated space must not exceed the fair rental value of comparable space as established by an independent appraisal of comparable space and facilities in a privately-owned building in the same locality.

ii. The value of loaned equipment must not exceed its fair rental value.

(5) Documentation. The following requirements pertain to the recipient's supporting records for in-kind contributions from third parties:

a. Volunteer services must be documented and, to the extent feasible, supported by the same methods used by the recipient for its own employees.

b. The basis for determining the valuation for personal services and property must be documented.

APPENDIX B – WAIVER REQUESTS FOR: FOREIGN ENTITY PARTICIPATION; AND FOREIGN WORK

Waiver for Foreign Entity Participation

For projects selected under this FOA, all recipients and subrecipients must be organized, chartered or incorporated (or otherwise formed) under the laws of a state or territory of the United States and have a physical location for business operations in the United States. To request a waiver of this requirement, an applicant must submit an explicit waiver request in the Full Application.

WAIVER CRITERIA

Foreign entities seeking to participate in a project funded under this FOA must demonstrate to the satisfaction of DOE that:

a. Its participation is in the best interest of the U.S. industry and U.S. economic development;
b. The project team has appropriate measures in place to control sensitive information and protect against unauthorized transfer of scientific and technical information;
c. Adequate protocols exist between the U.S. subsidiary and its foreign parent organization to comply with export control laws and any obligations to protect proprietary information from the foreign parent organization;
d. The work is conducted within the U.S. and the entity acknowledges and demonstrates that it has the intent and ability to comply with the U.S. Competitiveness Provision; and
e. The foreign entity will satisfy other conditions that may be deemed necessary by DOE to protect U.S. government interests.

Content for Waiver Request

A Foreign Entity waiver request must include the following:

a. Information about the entity: name, point of contact, and proposed type of involvement with the Institute;
b. Country of incorporation, the extent of the ownership/level control by foreign entities, whether the entity is state owned or controlled, a summary of the ownership breakdown of the foreign entity and the percentage of ownership/control by foreign entities, foreign shareholders, foreign state or foreign individuals;
c. The rationale for proposing a foreign entity participate (must address criteria above);
d. A description of the project’s anticipated contributions to the U.S. economy;

- How the project will benefit the U.S., including manufacturing, contributions to employment in the U.S. and growth in new markets and jobs in the U.S.;
- How the project will promote domestic American manufacturing of products and/or services;

e. A description of how the foreign entity's participation is essential to the project;
f. A description of the likelihood of Intellectual Property (IP) being created from the work and the treatment of any such IP; and
g. Countries where the work will be performed (Note: if any work is proposed to be conducted outside the U.S., the applicant must also complete a separate request foreign work waiver).

DOE may also require:

- A risk assessment with respect to IP and data protection protocols that includes the export control risk based on the data protection protocols, the technology being developed and the foreign entity and country. These submissions could be prepared by the project lead, but the prime recipient must make a representation to DOE as to whether it believes the data protection protocols are adequate and make a representation of the risk assessment – high, medium or low risk of data leakage to a foreign entity.
- Additional language be added to any agreement or subagreement to protect IP, mitigate risk or other related purposes.

DOE may require additional information before considering the waiver request.

The applicant does not have the right to appeal DOE's decision concerning a waiver request.

Waiver for Performance of Work in the United States (Foreign Work Waiver)

As set forth in Section IV.I.iii., all work under funding under this FOA must be performed in the United States. To seek a waiver of the Performance of Work in the United States requirement, the applicant must submit an explicit waiver request in the Full Application. A separate waiver request must be submitted for each entity proposing performance of work outside of the United States.

Overall, a waiver request must demonstrate to the satisfaction of DOE that it would further the purposes of this FOA and is otherwise in the economic interests of the United States to perform work outside of the United States. A request for a foreign work waiver must include the following:

- The rationale for performing the work outside the U.S. ("foreign work");
- A description of the work proposed to be performed outside the U.S.;

- An explanation as to how the foreign work is essential to the project;
- A description of the anticipated benefits to be realized by the proposed foreign work and the anticipated contributions to the US economy;
- The associated benefits to be realized and the contribution to the project from the foreign work;
- How the foreign work will benefit the U.S., including manufacturing, contributions to employment in the U.S. and growth in new markets and jobs in the U.S.;
- How the foreign work will promote domestic American manufacturing of products and/or services;
- A description of the likelihood of Intellectual Property (IP) being created from the foreign work and the treatment of any such IP;
- The total estimated cost (DOE and recipient cost share) of the proposed foreign work;
- The countries in which the foreign work is proposed to be performed; and
- The name of the entity that would perform the foreign work.

DOE may require additional information before considering the waiver request.

The applicant does not have the right to appeal DOE’s decision concerning a waiver request.

APPENDIX C – REQUIRED USE OF IRON, STEEL, MANUFACTURED PRODUCTS, AND CONSTRUCTION MATERIALS PRODUCED IN THE UNITED STATES

BUY AMERICA REQUIREMENTS FOR INFRASTRUCTURE PROJECTS

A. Definitions
For purposes of the Buy America requirements, the following definitions apply:

Construction materials includes an article, material, or supply—other than an item of primarily iron or steel; a manufactured product; cement and cementitious materials; aggregates such as stone, sand, or gravel; or aggregate binding agents or additives[56] —that is or consists primarily of:

- non-ferrous metals;
- plastic and polymer-based products (including polyvinylchloride, composite building materials, and polymers used in fiber optic cables);
- glass (including optic glass);
- lumber; or
- drywall.

Applicants may also seek a DOE waiver of domestic procurement requirements based on applicable public interest factors, such as relating to minor components, international trade obligations, or other considerations.

Infrastructure includes, at a minimum, the structures, facilities, and equipment for, in the United States, Roads, highways, and bridges; public transportation; Dams, ports, harbors, and other maritime facilities; InterCity passenger and freight railroads; Freight and intermodal facilities; airports; Water systems, including drinking water and wastewater systems; Electrical transmission facilities and systems; utilities; broadband infrastructure; and buildings and real property. Infrastructure includes facilities that generate, transport, and distribute energy.

In addition to the above, the infrastructure in question must be publicly-owned or must serve a public function; privately owned infrastructure that is solely utilized for private use is not considered "infrastructure" for purposes of Buy America applicability. The Agency, not the applicant, will have the final say as to whether a given project includes infrastructure, as defined herein.

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[56] BIL, § 70917(c)(1).

For this FOA specifically, all projects subject to this FOA are considered "infrastructure" within the Buy America provision of BIL.

Project means the construction, alteration, maintenance, or repair of infrastructure in the United States.

B. Buy America Requirements for Infrastructure Projects ("Buy America" requirements)
In accordance with section 70914 of the BIL, none of the project funds (includes federal share and recipient cost share) may be used for a project for infrastructure unless:

(1) all iron and steel used in the project are produced in the United States--This means all manufacturing processes, from the initial melting stage through the application of coatings, occurred in the United States;

(2) all manufactured products used in the project are produced in the United States—this means the manufactured product was manufactured in the United States; and the cost of the components of the manufactured product that are mined, produced, or manufactured in the United States is greater than 55 percent of the total cost of all components of the manufactured product, unless another standard for determining the minimum amount of domestic content of the manufactured product has been established under applicable law or regulation; and

(3) all construction materials[57] are manufactured in the United States—this means that all manufacturing processes for the construction material occurred in the United States.

The Buy America requirements only apply to articles, materials, and supplies that are consumed in, incorporated into, or affixed to an infrastructure project. As such, it does not apply to tools, equipment, and supplies, such as temporary scaffolding, brought to the construction site and removed at or before the completion of the infrastructure project. Nor does the Buy America requirements apply to equipment and furnishings, such as movable chairs, desks, and portable computer equipment, that are used at or within the finished infrastructure project, but are not an integral part of the structure or permanently affixed to the infrastructure project.

These requirements must flow down to all sub-awards, all contracts, subcontracts and purchase orders for work performed under the proposed project, except where the prime recipient is a for-profit entity. Based on guidance from Office of Management and Budget (OMB) Memorandum M-22-11, the Buy America requirements of the BIL do not apply to DOE projects in which the prime recipient is a for-profit entity; the requirements only apply to projects whose prime recipient is a State, local government, Indian tribe, Institution of Higher Education, or nonprofit organization.

[57] Excludes cement and cementitious materials, aggregates such as stone, sand, or gravel, or aggregate binding agents or additives.

For additional information related to the application and implementation of these Buy America requirements, please see OMB Memorandum M-22-11, issued April 18, 2022: https://www.whitehouse.gov/wp-content/uploads/2022/04/M-22-11.pdf

Note that for all applicants—both non-Federal entities and for-profit entities—DOE is including a Program Policy Factor that the Selection Official may consider in determining which Full Applications to select for award negotiations that considers whether the applicant has made a commitment to procure U.S. iron, steel, manufactured products, and construction materials in its project.

C. DOE Submission Requirements for Full Application

Within the first two pages of the workplan, applicants must provide a short statement on whether the project will involve the construction, alteration, and/or repair of infrastructure in the United States. The ultimate determination about whether a project includes infrastructure remains with DOE, but the applicant's statement will assist project planning and integration of domestic preference requirements, which may impact the project's proposed budget.

D. Waivers

In limited circumstances, DOE may waive the application of the Buy America requirements where DOE determines that:

(1) applying the Buy America requirements would be inconsistent with the public interest;

(2) the types of iron, steel, manufactured products, or construction materials are not produced in the United States in sufficient and reasonably available quantities or of a satisfactory quality; or

(3) the inclusion of iron, steel, manufactured products, or construction materials produced in the United States will increase the cost of the overall project by more than 25 percent.

If an applicant is seeking a waiver of the Buy America requirements, it must include a written waiver request with the Full Application. A waiver request must include:

- A detailed justification for the use of "non-domestic" iron, steel, manufactured products, or construction materials to include an explanation as to how the non-domestic item(s) is essential to the project
- A certification that the applicant or recipient made a good faith effort to solicit bids for domestic products supported by terms included in requests for proposals, contracts, and nonproprietary communications with potential suppliers;
- Applicant /Recipient name and Unique Entity Identifier (UEI)
- Total estimated project cost, DOE and cost-share amounts

- Project description and location (to the extent known)
- List and description of iron or steel item(s), manufactured goods, and construction material(s) the applicant or recipient seeks to waive from Domestic Content Procurement Preference requirement, including name, cost, country(ies) of origin (if known), and relevant PSC and NAICS code for each.
- Waiver justification including due diligence performed (e.g., market research, industry outreach) by the applicant or recipient
- Anticipated impact if no waiver is issued

DOE may require additional information before considering the waiver request.

Waiver requests are subject to public comment periods of no less than 15 days and must be reviewed by the Made in America Office. There may be instances where an award qualifies, in whole or in part, for an existing waiver described at https://www.madeinamerica.gov/financial-assistance/.

The applicant does not have the right to appeal DOE's decision concerning a waiver request.

APPENDIX D – STATEMENT OF PROJECT OBJECTIVES

Background/Instructions*: Prospective recipients of awards funded from Funding Opportunity Announcement DE-FOA-0002740 (FOA 2740) must prepare/submit a detailed statement of project objectives (SOPO) that addresses how the project objectives will be met. The SOPO must contain a clear, concise description of all activities that will be completed during project performance and follow the structure/format outlined below. Since the SOPO may be released (in whole or in part) to the public by the Department of Energy (DOE) after award, it shall not contain proprietary or confidential business information.*

*The SOPO generally consists of less than five (**5**) pages to describe the proposed work. Prospective recipients of FOA 2740 funding (FOA 2740 Recipient) shall prepare the SOPO according to the format provided in the SOPO template and in accordance with the application content and form requirements identified in Section IV Of the FOA.*

This Background/Instructions section as well as italicized text in the SOPO template is intended to be instructional, is provided as guidance, and should be removed by the FOA 2740 recipient when preparing their SOPO. All other text (shown as normal font within the SOPO template) is to be included in the proposed SOPO.

In writing the Statement of Project Objectives (SOPO), ***avoid:*** *1) the use of proper nouns to minimize SOPO modifications in the event of changes to the project team, facilities, etc.; 2) figures and equations; 3) references to other documents and publications; and 4) details about past work and discussion of technical background (which should be covered elsewhere in the application narrative).*

[**BEGININNING OF SOPO TEMPLATE*****]***

STATEMENT OF PROJECT OBJECTIVES (SOPO)
Title of Project
(Insert the title of the work to be performed. Be concise and descriptive)

A. OBJECTIVES
Clearly and concisely describe the objective(s) of the project. If the project includes multiple phases of work, describe the objective(s) for each phase. This section should not exceed one-half page.

B. SCOPE OF WORK

Summarize the planned effort and approach to achieve the proposed overall project objectives. For projects that involve multiple phases of work, specific scope statement(s) should be defined for each phase. This section should not exceed one-half page.

C. TASKS TO BE PERFORMED

Unless otherwise stated, all SOPOs will include tasks for Project Management Plan, National Environmental Policy Act (NEPA) Compliance, and Cybersecurity Plan (CSP) as instructed below. Further, the applicant should include clear and concise descriptions of their planned tasks (and subtasks if needed). Tasks are to be organized in a logical sequence and grouped into corresponding phases, if applicable.

Task 1.0: Project Management and Planning

Subtask 1.1 – Project Management Plan (PMP):

Within 30 days of award, the Recipient shall submit a Project Management Plan (PMP) to the designated Federal Project Officer (FPO). The Recipient shall not proceed beyond Task 1.0 until the PMP has been accepted by the FPO.

The PMP shall be revised and resubmitted as often as necessary, during the course of the project, to capture any major/significant changes to the planned approach, budget, key personnel, major resources, etc.

The Recipient shall manage and direct the project in accordance with the accepted PMP to meet all technical, schedule and budget objectives and requirements. The Recipient will coordinate activities to effectively accomplish the work. The Recipient will ensure that project plans, results, and decisions are appropriately documented, and that project reporting and briefing requirements are satisfied.

Subtask 1.2: National Environmental Policy Act (NEPA) Compliance

As required, the Recipient shall provide the documentation necessary for NEPA compliance.

Subtask 1.3: Cybersecurity Plan (CSP)*

The CSP shall be revised and resubmitted as often as necessary, during the course of the project, to capture any major/significant changes.

**Applicable to Topic Area 2 [Smart Grid Investments (40107)] and Topic Area 3 (Innovative Grid Resilience Program (40103(b)) only*

Subtask 1.4: Continuation Briefing(s):

The Recipient will brief DOE on roughly an annual basis to explain the plans, progress and results of the technical effort. The briefing shall also describe performance relative to project success criteria, milestones, and the Go/No-Go Decision point that are documented in the Project Management Plan (PMP).

Include additional tasks and subtasks as appropriate using the following format. For projects that involve multiple phases of work, label the start of each phase (such as "Phase 1", etc.), state the title, and provide a brief narrative describing the objective(s) and scope for the phase.

Task 2.0 - (State title of task and provide description)

Subtask 2.1 - (State title of subtask and provide description)

Task 3.0 - (State title of task and provide description)

Subtask 3.1 - (State title of subtask and provide description)

Task 4.0 - (State title of task and provide description

Subtask 4.1 - (State title of subtask and provide description)

D. DELIVERABLES

The Recipient shall include a list of deliverables that will be submitted during the project.

Subtask 1.1: Project Management Plan

Subtask 1.3 – Cybersecurity Plan (*if applicable)

Subtask 1.4 – Pre-Continuation Briefing Document(s)

List additional deliverables as appropriate including any documents that will be delivered to DOE.

In addition to the deliverables listed above, the Recipient shall submit all periodic, topical, final, and other reports in accordance with the Federal Assistance Reporting Checklist and accompanying instructions.

E. BRIEFINGS/TECHNICAL PRESENTATIONS

The Recipient shall prepare, and present periodic briefings, technical presentations and demonstrations as requested by the Federal Project Officer, which may be held at a DOE or the Recipient's facility, other mutually agreeable location, or via webinar. Such meetings may include all or a combination of the following:

Kickoff Briefing - Not more than 30 days after submission of the Project Management Plan, the Recipient shall prepare and present a project summary briefing as part of a Project Kickoff Meeting.

Pre-Continuation Briefing - Not less than 90 days prior to the planned start of a budget period, the Recipient shall brief the DOE on the results to date, and their plans for the subsequent periods of work. The DOE will consider the information from this briefing, as well as the content of deliverables submitted to date, prior to authorizing continuing the project.

Final Project Briefing - Not less than 30 days prior to the end of the project, the Recipient shall prepare and present a Final Project Briefing on the results and accomplishments of the entire project.

Other Briefings – The Recipient shall prepare and present technical, financial, and/or administrative briefings as requested by the DOE. Additionally, the DOE may require Recipients to make technical presentations at national and/or industry conferences.

[**END OF SOPO TEMPLATE*****]***

APPENDIX E – CYBERSECURITY PLAN

In accordance with BIL Section 40126, DOE requires Topic Area 2 and Topic Area 3 awardees to submit a cybersecurity plan during award negotiations and prior to receiving funding.[58] These plans are intended to foster a cybersecurity-by-design approach[59] for BIL efforts. The Department will also use these plans to ensure effective integration and coordination across its research, development, and demonstration programs.

The Department recommends using open guidance and standards such as the National Institute of Standards and Technology's (NIST) Cybersecurity Framework (CSF), the DOE Cybersecurity Capability Maturity Model (C2M2), and the Cybersecurity and Infrastructure Security Agency (CISA) cybersecurity performance goals for critical infrastructure and control systems.[60] The cybersecurity plan created pursuant to Section 40126 should document any deviation from open standards, as well as the utilization of proprietary standards where the awardee determines that such deviation is necessary.

- Cybersecurity plans should be commensurate to the threats and vulnerabilities associated with the proposed efforts and demonstrate the cybersecurity maturity of the project.
- Cybersecurity plans may cover a range of topics relevant to the proposed project, e.g., software development lifecycle, third-party risks, and incident reporting.
- At a minimum, the Cybersecurity Plan should address questions noted in IIJA section 40126 (b) 'Contents of Cybersecurity Plan'.[61]
    - (1) plans to maintain cybersecurity between networks, systems, devices, applications, or components-
        - (A) within the proposed solution of the project; and
        - (B) at the necessary external interfaces at the proposed solution boundaries;

[58] 42 USC §18725

[59] Security must be baked into the development process, not bolted on. Security risk evaluation and mitigation measures should be an active component in a project (or product) lifecycle – from early development stages to implementation.

[60] NERC critical infrastructure protection (CIP) standards for entities responsible for the availability and reliability of the bulk electric system. NIST IR 7628: 2 Smart grid cyber security strategy and requirements. NIST SP800-53, Recommended Security Controls for Federal Information Systems and Organizations: Catalog of security controls in 18 categories, along with profiles for low-, moderate-, and high-impact systems. NIST SP800-82, Guide to Industrial Control Systems (ICS) Security. NIST SP800-39, Integrated Enterprise-Wide Risk Management: Organization, mission, and information system view. AMI System Security Requirements: Security requirements for advanced metering infrastructure. ISO (International Organization for Standardization) 27001, Information Security Management Systems: Guidance on establishing governance and control over security activities (this document must be purchased). IEEE (Institute of Electrical and Electronics Engineers) 1686-2007, Standard for Substation Intelligent Electronic Devices (IEDs) Cyber Security Capabilities (this document must be purchased). DOE Cybersecurity Capability Maturity Model (C2M2). CISA cybersecurity performance goals for critical infrastructure and control systems directed by the National Security Presidential Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems, found at https://www.cisa.gov/cpgs

[61] 42 USC §18725

- (2) will perform ongoing evaluation of cybersecurity risks to address issues as the issues arise throughout the life of the proposed solution;
- (3) will report known or suspected network or system compromises of the project to DOE; and
- (4) will leverage applicable cybersecurity programs of the Department, including cyber vulnerability testing and security engineering evaluations.

- Projects receiving funding under this program must utilize open protocols and standards (including Internet-based protocols and standards) if available and appropriate.[62]

[62] 42 USC §17386(e)(1)(B)

APPENDIX F – PROJECT DESCRIPTION AND ASSURANCES DOCUMENT TEMPLATE (PDAD)

Project title:

Applicant Name:

Applicant Address:

Names of all team member organizations (if applicable):

Principal Investigator (Name, Address if different than Applicant's, Phone Number, E-mail):

Business Point of Contact (Name, Address if different than Applicant's, Phone Number, E-mail):

Include any statements regarding confidentiality.

Federal Share:
Cost Share:
Total Estimated Project Cost:

Item 1: Specify (mark with "X")" the FOA Topic Area and as applicable the Area of Interest (AOI):

________Topic Area 1: **Grid Resilience Grants** (BIL section 40101(c))

________Topic Area 2: **Smart Grid Grants** (BIL section 40107)

________Topic Area 3: **Grid Innovation Program** (BIL section 40103(b)) – Area of Interest 1 (**Transmission** System Applications)

________Topic Area 3: **Grid Innovation Program** (BIL section 40103(b)) – Area of Interest 2 (**Distribution** System Applications)

________Topic Area 3: **Grid Innovation Program** (BIL section 40103(b)) – Area of Interest 3 (**Combination** System Applications)

TOPIC AREA 1 Specific Items:

Item 2: Specify (mark with "X")" the entity type of the applicant organization:

________electric grid operator

________electricity storage operator

________electricity generator

________transmission owner or operator

________distribution provider

________fuel supplier

If further description is needed for the specified entity type, please provide below:

Item 3: Please provide the total amount (USD) of qualifying resilience investments (as outlined in DE-FOA-00002740) that has been spent for the previous 3 years. Please also provide the time period utilized for calculation of this amount.

Total Amount:
Time Period for Resilience Investments:

Note: Topic Area 1 applicants must submit as part of their application, a report detailing past, current, and future efforts by the eligible entity to reduce the likelihood and consequences of disruptive events. This report should include efforts over at least the previous 3 years and at least the next 3 years and any broader resilience strategy used by the applicant.

Item 4: Is the eligible entity a Small Utility as defined in DE-FOA-0002740 (sells no more than 4,000,000 MWh of electricity per year)? If NO is selected, skip to Item 7.

________Yes

________No

Note: If YES, applicant must provide their Form 861 for the last reporting year submitted to the Energy Information Administration (EIA).

Item 5: Per BIL section 40101(e)(2) (C) APPLICATION LIMITATIONS.—An eligible entity may not submit an application for a grant provided by the Secretary under subsection (c) and a grant provided by a State or Indian Tribe pursuant to subsection (d) during the same application cycle.

Therefore, is the eligible entity a Subaward/Subcontract recipient for an application submitted under IIJA Section 40101(d), ALRD 2736? If "YES", please describe the differences between the GRIP FOA 2740 application [40101(c)] and the ALRD 2736 [40101(d)] applications in the box below:

________Yes

_________No

TOPIC AREA 2 Specific

No items

TOPIC AREA 3 Specific

Item 6: Specify (mark with "X")" the entity type of the applicant organization:

_________a State

_________a combination of 2 or more States

_________an Indian Tribe

_________a unit of local government

_________a public utility commission

If further description is needed for the specified entity type, please provide below:

Item 7:

Authorized Organizational Representative (AOR): please provide name, address, phone number and e-mail address for the authorized agent to bind the entity

Authorized Organizational Representative (AOR):

Name:

Address:

Phone:

E-mail:

Item 8: Signature of Authorized Organizational Representative (AOR)

____-

Strategic Resilience of Northeast Grids (STRONG)

FOA Number: DE-FOA-0002740
BIL – Grid Resilience and Innovation Partnerships (GRIP)
Topic Area 1: Grid Resilience Grants (BIL Sec. 40101(c))

Team Member Organizations

The Narragansett Electric Company d/b/a Rhode Island Energy, Prime Applicant
PPL Services Corporation, Team Member

Technical Point of Contact
Kathy Castro
Director of Asset Management and Planning
Rhode Island Energy
KRCastro@RIEnergy.com
508-594-0417

Business Point of Contact
Brian Grzesiuk
Senior Finance Manager
Rhode Island Energy
BGrzesiuk@RIEnergy.com
774-563-8451

Project Location
State of Rhode Island

Rhode Island Energy™
a PPL company

Project Overview

Background: Rhode Island is uniquely positioned to lead "STRONG" investments

Strategic electrification using clean energy resources is a mature and promising pathway to decarbonization, underscoring the importance of building the resilience of the electric grid. Simultaneously, the grid is becoming increasingly threatened by the impacts of climate change and extreme weather. Failure to recognize the urgent need to make the electric grid more resilient will result in public health and safety risks and threaten decarbonization efforts. Despite these pressures, utilities across the nation are struggling to prioritize investments in resilience among other critically necessary investments, ranging from traditional asset replacement programs to grid modernization that enables renewable distributed energy resources. On one hand, resilience investments are critical; on the other, demands on customers must be balanced, especially within the current macroeconomic landscape and historically high energy supply costs across New England.

Project Goal: In this proposal[1], prime applicant and the grant recipient Rhode Island Energy (RIE) and team member and RIE affiliate and services company PPL Services Corporation (PPL) (together referred to as "the Project Team"), propose a suite of investments to build *Strategic Resilience of Northeast Grids* (STRONG) and <u>offer a replicable framework to build resilience, defer to communities to maximize local value, and leverage external supplemental private funding to achieve more resilience at a lower cost to customers.</u>

Prime applicant, RIE, is an electric distribution company, transmission owner and operator, and distribution provider, serving nearly 99% of the state's customers (nearly 500,000 customers). RIE's network electric power system lies entirely within coastal territory[2] where the impacts of coastal storms and flooding are already visible.[3] Rhode Island is an advantageous location for work set forth in the STRONG proposal because of its unique vulnerability to and history of coastal storms and flooding, and its nation-leading clean energy and climate mandates.[4] Rhode Island's small land area (1200 square miles), low elevation, outsized coastline (400 miles), and extreme population density[5] render the state particularly vulnerable to the impacts of coastal storms (hurricanes, nor'easters, bomb cyclones, wind events) and flooding (riverine, tidal, storm surge, sea level rise). Storms and flooding events are expected to increase in both frequency and severity,[6] with catastrophic floods in 2010 and 2022 serving as signs of increasing intense rainfall. Furthermore, Rhode Island's disadvantaged communities (DACs) are the most vulnerable to climate change, underscoring the urgent need for investment in climate mitigation and adaptation.[7]

[1] Throughout: "proposal" refers to the entirety of investments, actions, and tasks proposed herein. The total proposal cost is $171.7 million, comprised of $85.8 million federal share and $85.9 million non-federal share (50%).
[2] "Rhode Island." 2022. Office of Coastal Management. December 8, 2022. https://coast.noaa.gov/states/rhode-island.html.
[3] "Billion-Dollar Weather and Climate Disasters." 2022. National Centers for Environmental Information (NCEI). 2022. https://www.ncei.noaa.gov/access/billions/summary-stats/RI/2002-2022.
[4] 100% renewable electricity by 2033; net-zero greenhouse gas emissions by 2050
[5] "Office of Energy Efficiency and Renewable Energy." Fact #661: Population Density. February 7, 2011. https://www.energy.gov/eere/vehicles/fact-661-february-7-2011-population-density.
[6] "Adapting to Coastal Climate Change." 2022. Coastal Resources Center. 2022. https://www.crc.uri.edu/projects_page/adapting-to-coastal-climate-change/.
[7] "Rhode Island Department of Health Climate Change and Health Program Needs Assessment Summary."2021.

This proposal is fully aligned with Rhode Island's resilience policy and RIE's resilience strategy**.** Climate resilience is at the forefront of Rhode Island's policy conversation and actions. Rhode Island's 2021 Act on Climate and predecessor 2014 Resilient Rhode Island Act specifically contemplate the importance of climate resilience by tasking Rhode Island's cabinet-level coordinating group, the Rhode Island Executive Climate Change Coordinating Council (RI EC4), with "Identify[ing] strategies to prepare for… communicate… incentivize businesses, institutions, and industry to adapt" and "Work[ing] with municipalities… Identify[ing] and leverage[ing] federal, state, and private funding opportunities."[8] Rhode Island's 2018 *Resilient Rhody* report established more than 60 priority resilience actions developed through interagency and stakeholder collaboration, with the objective of coordinating and catalyzing action to protect Rhode Island's robust tourism industry, vibrant coastal resources and culture, and critical community infrastructure. This proposal directly advances *Resilient Rhody's* first utility resilience action item by proposing "energy resilience solutions [that] could alleviate the impacts of power outages."[9] Roughly 80% of Rhode Island's municipalities have participated in the Rhode Island Municipal Resilience Program, underscoring the need and urgency communities see for actions that reduce the impacts of extreme weather on power availability in their *Community Resilience Building Workshop Summary of Findings* reports. RIE's grid resilience strategy aligns with Rhode Island's policy emphasis on climate resilience.

RIE's Grid Resilience Strategy

(1) Regular development of construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure
(2) Vegetation management
(3) Asset management practices and distribution system planning studies that are executed to identify existing and project future system performance concerns and the infrastructure development required to address the concerns
(4) Consideration of both reactive and proactive infrastructure development programs that adopt new, replace, and/or modify existing grid assets
(5) Development, continued refinement, training, and execution of RIE's Emergency Response Plan.

RIE has developed robust processes in each of these areas which allow it to respond both proactively and reactively as the impacts of climate change on distribution system performance are realized. RIE recognizes that, while the threat of climate change is significant, it is not an acute concern that can be resolved through isolated or short-term initiatives. Accordingly, preparing for and responding to climate change is embedded in the way RIE plans, constructs, and operates its system as a normal course of business. As the understanding of the magnitude, scope, and breadth of climate-related challenges matures, the flexibility and robustness of RIE's processes will allow additional measures to be developed and implemented. This proposal is fully aligned with Rhode Island resilience policy and RIE's resilience strategy.[10]

[8] Chapter 6.2 2021 Act on Climate. 2021. Vol. R.I. Gen. Laws § 42-6.2-2. http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.htm.
[9] "Resilient Rhody." 2018. State of Rhode Island. https://climatechange.ri.gov/sites/g/files/xkgbur481/files/documents/resilientrhody18.pdf.
[10] There are no potential long-term constraints this proposal will have on the community's access to natural resources (e.g., water) and Tribal cultural resources.

DOE Impact: This work will not proceed at this pace or scale without federal funding. Federal funding will both accelerate and unlock a number of resilience investments. Without federal funding, 100% of proposal costs will be recovered from customers; if selected, federal funding will go directly to reducing costs for all Rhode Island customers. Furthermore, federal funding will enable two significant and replicable advancements in community engagement. First, the Project Team will pilot an enhanced community and customer engagement strategy that provides more visibility and education about how RIE is making STRONG resilience investments. Second, the Project Team will develop and pilot the Community Prioritized Resilience Investment Framework to bring community voices to the discussion about how, when, and where to make resilience investments, with the objective of pulling in supplemental private funding to reduce customer costs. The ultimate project goal is to accelerate and strengthen reliability and resilience beyond the development baseline.[11]

Community Benefits: First, 100% of federal funding will directly reduce customer cost recovery. Second, the Project Team will pilot two significant and replicable advancements in community engagement: Enhanced Community Engagement and the Community Prioritized Resilience Investment (CPRI) Framework. Altogether, this proposal makes significant strides in increasing energy resilience, reducing energy burden, and advancing energy democracy.

Replicability: This proposal is designed with replicability as a primary objective. The Project Team will maximize impact of federal funding through two replicable frameworks: enhanced community engagement and the Community Prioritized Resilience Investment Framework. Both frameworks, along with lessons learned and insights, will be described in detailed deliverables for broad dissemination.

Technical Description

Relevance and Outcomes: Proposal directly advances FOA objectives, improves resilience

The Project Team's approach is to strengthen resilience through a holistic portfolio of investments that (1) minimizes the consequences of an outage caused by coastal storms and flooding and (2) minimizes the economic impact resulting from outage duration or frequency.

Supporting State Policy: This proposal and its intended outcomes directly align with Rhode Island's climate resilience policy. Specifically, the steel-in-the-ground investments in this proposal are each aligned with Rhode Island's focus on municipal climate resilience following the 2014 Resilience Rhode Island Act and the *Resilient Rhody* report. The Project Team connects each of the proposed projects with municipal concerns and priorities, as described in each municipality's *Community Resilience Building Workshop Summary of Findings*, a report generated through a municipality's participation in the Rhode Island Municipal Resilience Program.[12] Furthermore, the Community-Prioritized Resilience Investment (CPRI) Framework will allow municipalities to flexibility pursue their energy resilience priorities.

Feasibility: This proposal is both technically and practically feasible, backed by the demonstrated success and experience of the Project Team. Each investment design has been

[11] RIE generally uses the term 'reliability' to refer to the day-to-day ability of the system to prevent interruptions and restore customers after an interruption and the term 'resiliency' to refer to the ability of the system to prevent interruptions and restore customers after an interruption during major events and storms.

[12] For more information and comprehensive inventory of participating municipalities, see https://riib.org/solutions/programs/municipal-resilience-program/.

analyzed and deemed feasible to design and construct, given information known at this stage. **Innovation and Impacts:** This portfolio contains two types of investments: a comprehensive suite of steel-in-the-ground resilience investments and three resilience projects piloted through the CPRI Framework. With federal funding, the Project Team will accelerate, expand, and unlock these resilience projects – and their resulting benefits – that would not have occurred but-for federal funding. Furthermore, the CPRI Framework can be a replicable model deployed at-scale to optimize resilience investments nationwide. The Project Team's portfolio approach of pairing steel-in-the-ground projects with collaborative resilience investments will a) support the transformation of community, regional, interregional, and national resilience, b) catalyze and leverage private sector and non-federal public capital for impactful infrastructure deployments, and c) advance community benefits.

Table 1: Proposed Grid Resilience Investments

	Investment	Brief Description
Steel in the Ground	**Mitigate substation flooding**	Rebuild the Westerly Substation at higher elevation and add compensatory storage for flood waters. This investment will improve energy resilience for a DAC.
	Strengthen substation resilience and accommodate electrification	Replace aged assets and upgrade Merton Substation to improve operations, increase reliability, and accommodate electrification.
	Accelerate new feeder to improve reliability and contingencies	Accelerate a new Tiverton feeder to spread existing electric load and resolve load-at-risk conditions to improve service reliability and resilience to disruptive events.
	Relocate coastal feeders underground	Relocate existing overhead feeders in Misquamicut and Oakland Beach underground to reduce outages due to coastal storms and flooding.
	Address wind-driven outages for rural feeder	Reconductor and relocate a critical portion of a feeder to reduce outages from intense winds in the heavily treed community of Ashaway.
	Relocate transmission line underground	Relocate approximately 5,400 feet of an existing transmission line underground. This transmission line is of particular significance to two DACs.
	Utility-scale storage to improve resilience	Install three utility-scale battery energy storage systems to enhance system adaptive capacity during disruptive events and improve resilience for two DACs.
Replicable Framework to Maximize Resilience Impact	**Community-Prioritized Resilience Investment (CPRI) Framework**	Develop and pilot a framework for incorporating community insight into planning and integrating non-customer funding to unlock investments with local resilience and non-resilience value. Demonstrate how utility planners can operationalize 'energy democracy.' At least one DAC served.

> A comprehensive suite of steel-in-the-ground resilience improvements

The Project Team identified investments that provide important resilience benefits but have been deprioritized for short-term investment among other critical infrastructure needs. These investments address transmission and distribution system needs using a combination of both traditional resilience measures (undergrounding, hardening, flood mitigation) and innovation (energy storage to improve reliability and resilience).[13] The benefits of these investments will flow to communities across the entire state, with half of the proposed investments specifically benefiting DACs.[14]

Mitigate substation flooding

The Town of Westerly identified precipitation-driven and coastal flooding as top hazards, and power outages as a specific concern and challenge in their 2019 *Community Resilience Building Workshop Summary of Findings*.[15] The Westerly Substation is currently in a flood-prone area that has experienced two major floods in the last 20 years. A series of storms in 2010 demonstrated the severity of flooding this substation will continue to see and validated flood maps used for planning. These storms caused the Pawcatuck River to experience the highest levels of flooding recorded. Informal markings in the control enclosure at Westerly substation indicate waters reached an elevation of 14.9', nearly 5' above the level of the substation's floor. The flooding extensively damaged substation equipment, driving piecemeal replacement of control equipment, capacitor banks, and all equipment housed on the ground. Following this flooding event, FEMA updated its Flood Insurance Rate Map.[16] Westerly Substation is now entirely located within the 100-yr floodplain.

The Project Team proposes to entirely rebuild this substation at a higher elevation at its current location and add compensatory storage located in an adjacent (or nearby) parcel of land. The proposed project – partial elevation with compensatory storage – is a gold star model of flood mitigation. Designating compensatory storage allows flood waters to flow to a pre-

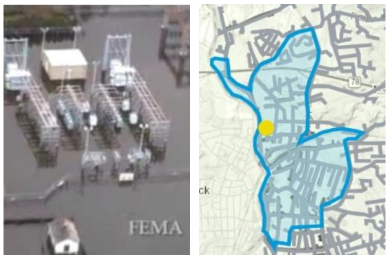
[13] The investment portfolio satisfies Topic Area 1's eligible use requirements, including undergrounding electrical equipment; utility pole management; the use or construction of distributed energy resources for enhancing system adaptive capacity during disruptive events (specifically, battery storage); and the hardening of power lines, facilities, substations, and other systems.

[14] The Project Team adopts DOE's definition of disadvantaged communities (DACs) based on the July 20, 2021, Memorandum for the Heads of Departments and Agencies from Shalanda D. Young, Brenda Mallory, and Gina McCarthy. DACs are "either a group of individuals living in geographic proximity to one another, or a geographically dispersed set of individuals (such as migrant workers or Native Americans), where either type of group experiences common conditions" where those conditions may include, but are not limited to, "low income, high and/or persistent poverty; high unemployment and underemployment; racial and ethnic residential segregation, particularly where the segregation stems from discrimination by government entities; linguistic isolation; high housing cost burden and substandard housing; distressed neighborhoods; high transportation cost burden and/or low transportation access; disproportionate environmental stressor burden and high cumulative impacts; limited water and sanitation access and affordability; disproportionate impacts from climate change; high energy cost burden and low energy access; jobs lost through the energy transition; and access to healthcare." The Project Team used the Climate and Economic Justice Screening Tool (CEJST) as its primary tool for assessing impacts of proposed projects on disadvantaged communities. Where appropriate, the Project Team supplemented its analysis using tools developed by Rhode Island state agencies.

[15] https://riib.org/wp-content/uploads/2022/05/Westerly-MRP-CRB-Summary-of-Findings-Report-Final-September-2019-002.pdf; This report also identifies elevating utility transformer as a high-priority action.

[16] Map 44009C0139K contains the Westerly Substation

Fig. 2: Westerly Substation



Notes: The photo shows the extent of floodwaters from the 2010 flood (source: FEMA). The map overlays DAC tract 44009050801 on feeders served by the Westerly Substation (yellow) (source: CEJST).

approved location that limits risk of flooding to other neighboring and nearby parcels of land. Without this storage, flood waters would flow unpredictably to other parcels and exacerbate flooding elsewhere. The proposed compensatory storage at the Westerly Substation will be the first such instance of implementing this gold-star flood mitigation technique for RIE. RIE will develop a case study with lessons learned so that the Project Team can apply this technique throughout its territory and maximize impacts through replicability. Rebuilding the station at a higher elevation not only provides future protection against coastal storms and floods but will bring the Westerly Substation in line with current RIE standards. This solution will benefit the local DAC (and business district) by increasing energy resilience, including reducing outage frequency and duration.
The full scope of proposed flood mitigation is not within RIE's planned three-year future resilience investments [see *Report on Resilience Investments*]. At this time, the only planned work includes repairs, which would not prevent future flooding impacts and outages. With funding, investments would be accelerated and expanded to include flood mitigation measures.

Strengthen substation resilience and accommodate electrification

According to the City of Newport's 2020 *Community Resilience Building Workshop Summary of Findings*, hurricanes and nor-easters were identified as the hazards of greatest concern and the power distribution system as particularly vulnerable infrastructure.[17] The Merton Substation serves customers in Newport, RI, the southernmost municipality on Aquidneck Island. Commissioned into service in 1960, Merton Substation suffers from aging infrastructure and requires replacement and upgrades of various aging and troublesome assets to improve reliability and the thermal capacity of the feeders.

The Project Team will replace all existing equipment at Merton Substation with a 23kV to 13.8kV modular substation with one feeder and provisions for a second 13.8kV feeder (not part of this grant proposal). Distribution line work is also required to build the distribution circuit and convert the required 4kV load. With many pieces of equipment at this station ranging from 30 to 60 years of age, this investment will significantly improve the operations of the substation and increase reliability in surrounding communities.

Without federal funding, the proposed scope of work would be changed to rebuild the station as a 23kV-4kV station with no distribution system conversions. The distribution conversion scope is not within RIE's planned three-year future resilience investments [see *Report on Resilience Investments*]. With funding, these investments would be accelerated and expanded to include the important distribution conversion measures, which provide additional capacity for future strategic electrification. Heating electrification has been noted as a possible pathway to build climate resilience for customers on Aquidneck Island after experiencing a prolonged gas shut-off during a cold snap in January 2019.

[17] https://riib.org/wp-content/uploads/2022/05/Newport-CRB-Summary-of-Findings-Report-September-2020_5.pdf

Accelerate feeder resilience

The Town of Tiverton's 2021 *Community Resilience Building Workshop Summary of Findings* indicates power grid failure is a particular concern, arising from "increasing challenges of being prepared for the worst-case scenarios… particularly in the late summer with a high number of visitors and in the fall/winter months, when more intense storms coincide with colder weather."[18] There are currently four feeders served by the Tiverton Substation. These circuits are highly utilized under normal conditions (3 of the 4 circuits are at or above 95% loading) and under contingency or load-at-risk conditions. Prior study has identified the need to utilize an existing spare feeder position at the Tiverton Substation and extend this feeder into the distribution system to offload circuits. A new feeder provides additional normal and contingency loading availability. Existing load can be spread across the five circuits more evenly, and during load-at-risk events, there will be additional feeder tie points to pick up lost load, thereby providing much more reliable electrical service by restoring area customers at a faster rate. While this scope is not within RIE's planned three-year future resilience investments [see *Report on Resilience Investments*], a similar scope of work is contemplated within RIE's five-year investment plan. With funding, these investments would be accelerated.

Relocate coastal feeders underground

This investment consists of undergrounding three separate overhead circuits to improve grid resilience for coastal communities in Misquamicut and Oakland Beach. These coastal communities represent key pieces of Rhode Island's tourism economy and are a hallmark of its coastal culture. Therefore, increasing frequency and severity of coastal storms and flooding is more than just an issue of power outages, but the local way of life. To improve reliability, the Project Team proposes to relocate existing overhead conductors underground into new manhole and duct systems.

Underground distribution feeders have demonstrated benefits in reduced outage frequency, reduction in the total costs of post-storm restoration of the power system, reduced costs of vegetation management, and the potential for reduced damage to (and outages from) utility assets caused by motor vehicle crashes.

The Town of Westerly identified major storms and wind as top hazards, and power outages as a specific concern and challenge in their 2019 *Community Resilience Building Workshop Summary of Findings*.[19] The Town also identified the "burying of powerlines in critical corridors vulnerable to impacts from high wind and ice hazards" as a high-priority action. The overhead conductor along Atlantic Avenue in the village of Misquamicut is in an area prone to extreme weather events and flooding (94th percentile for projected flood risk according to CEJST). The communities and businesses served by this circuit have historically below-average service reliability and would benefit from investment.[20]

The City of Warwick identified coastal flooding as a top concern, powerlines as critical infrastructure, and Oakland Beach as a vulnerable locality in its 2020 *Community Resilience*

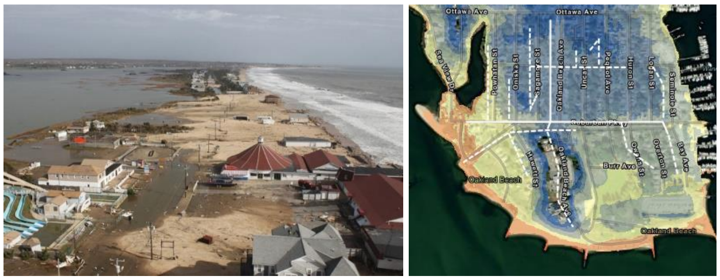
[18] https://riib.org/wp-content/uploads/2022/05/Final-Tiverton-Community-Resilience-Building-Summary-of-Findings-September-2021_1.pdf

[19] https://riib.org/wp-content/uploads/2022/05/Westerly-MRP-CRB-Summary-of-Findings-Report-Final-September-2019-002.pdf

[20] 2021 System Average Interruption Frequency Index (SAIFI) = 3.32. 2021 System Average Interruption Duration Index (SAIDI) = 240 minutes. RIE target SAIFI = 1.05, SAIDI = 71.9 minutes.

Building Workshop Summary of Findings.[21] The overhead circuit at Oakland Beach suffers from below-average reliability[22], impacts from recent storms, and expected increases in flooding (84th and 76th percentiles for projected flood risk, respectively; CEJST). The Project Team will reduce project risk through deliberate, robust, and thorough engagement with local communities throughout the process (more details provided in the Community Benefits Plan).

| Fig. 3: Flood Risk in Misquamicut and Oakland Beach



Notes: The left photo shows damages from Superstorm Sandy in Misquamicut, which impacted many historic homes, hotels, and restaurants in this tourism hub (source: RIDOT via RI CRMC Storm Tools). The left image shows an overlay of the proposed relocation underground at Oakland Beach on a map showing risk of flooding due to 100-year storm (source: RI CRMC Storm Tools).

<u>Address wind-driven outages for rural feeder</u>

Coastal storms often come with intense winds that can pose challenges for customers in rural and in-land coastal communities. While these communities may have a lower risk of sea level rise or storm surge, intense winds from coastal storms can result in more frequent and longer power outages. This investment improves resilience for the rural community of Ashaway.[23] Customers along a particular feeder experience this below-average service reliability first-hand. Due to the circuit being in a heavily treed area, with portions of the circuit located in hard to access rights-of-way (ROW) with bare wire construction, customers on this circuit experience longer interruption repair times that negatively impact reliability.

The Project Team will reconductor and relocate a critical portion of this feeder to the main roadway to increase normal and contingency loading availability, improve reliability, and alleviate access issues that currently slow outage restoration. The Project Team will reconductor using a larger diameter covered conductor in a spacer configuration (477 kcmil aluminum spacer wire), thereby increasing reliability and resilience to animal and tree contacts during storm events. Existing electrical conductors no longer required to carry electrical load will be deenergized and removed from the existing ROW. This scope is not within RIE's planned three-year future resilience investments [see *Report on Resilience Investments*]. With funding, these investments would be accelerated by up to three years. Project risks are standard (e.g. permits required) and will be mitigated through careful project planning, due diligence, and thoughtful community engagement (described in detail in the Community Benefits Plan).

<u>Relocate transmission line of significance to DAC communities underground</u>

An overhead transmission line connecting one of Rhode Island's six major generation facilities to downstream customers is exposed to coastal storms and flooding. The closest

[21] https://riib.org/wp-content/uploads/2022/05/Warwick-CRB-Summary-of-Findings-Report-November-2020_3.pdf Indeed, "conduct feasibility assessment for undergrounding utility lines in high-risk areas" is listed as a priority action.

[22] 2021 SAIFI = 2.26. RIE target SAIFI = 1.05.

[23] Ashaway is in the Town of Hopkinton, which is participating in the 2023 Cohort of the Municipal Resilience Program. As such, the Community Resilience Building Workshop Summary of Findings is not yet available.

support structure lies within 50' of the water and is exposed to storm surges. Conductors and other equipment associated with this line are also exposed and at risk of damage from extreme weather events. The Project Team will relocate approximately 4,400 feet of this transmission line underground using horizontal directional drilling (HDD) and approximately 1,000-feet of traditional open trench installation. The proposed route travels under the mouth of the Providence River in the City of Providence and meets land in the City of East Providence.[24] Relocating the line underground reduces the likelihood of permanent outages due to coastal storms. This project will build institutional capacity for HDD, a newer method for RIE.

Relocating this segment of the transmission line underground is also of local significance and may provide benefits for local DACs. The transmission line runs overhead a local park, an important greenspace for the surrounding urban communities. On the east, relocating the line underground may enhance economic development opportunity for a DAC in the City of East Providence, which is in the 90th percentile for linguistic isolation and 19th percentile for high school education.[25] To the west, relocating the line underground may have meaningful aesthetic value to a DAC in the City of Providence, which is in the 98th percentile for proximity to hazardous waste, 93th percentile for proximity to Risk Management Plan facilities, and 85th percentile for low-income, among other health, housing, transportation, and workforce development indicators.[26] Relocating the line out of sight is a meaningful symbol of Rhode Island's commitment to environmental justice.

The Project Team recognizes the potential technical, regulatory, permitting, financial, and community risks with this project, and has a thoughtful risk mitigation strategy for each. In collaboration with a recognized expert on HDD, the Project Team has identified a set of engineering analyses to conduct to assure technical feasibility. The Project Team identified a potential pathway for shared costs not borne by the general customer base. The Project Team also has a proactive and thoughtful community and stakeholder engagement plan (described in detail in the Community Benefits Plan).

Utility-scale energy storage to reduce outages for DAC communities

Two of Rhode Island's DACs are served by feeders with below-average reliability, and customers frequently experience reliability and outage issues during storm events. The Project Team proposes to install three utility-scale battery energy storage systems connected directly to the circuit to enhance system adaptive capacity during disruptive events. These batteries would be charged directly from the distribution system and would provide backup power to customers during potential outages. While utility-scale storage has demonstrated its ability to provide critical grid benefits, few utilities use batteries to enhance reliability and build resilience. Therefore, this use case for utility-scale batteries is likely not yet fully internalized

[24] The City of Providence identifies energy and utility infrastructure as a critical area of concern in its 2021 *Community Resilience Building Workshop Summary of Findings* (https://riib.org/wp-content/uploads/2022/05/Final-Providence-Community-Resilience-Building-Summary-of-Findings-July-2021_1.pdf). The City of East Providence similarly identifies power lines as a critical area of concern in its 2021 *Community Resilience Building Workshop Summary of Findings* (https://riib.org/wp-content/uploads/2022/05/Final-East-Providence-Community-Resilience-Building-Summary-of-Findings-June-2021_0.pdf).

[25] Tract 44007010400 according to the CEJST

[26] Tract 44007000600 according to the CEJST

into the value proposition of energy storage technology. The proposed projects will demonstrate this use case to the market. In the event of an award, the Project Team will develop a case study to disseminate insights.

Location 1 is anticipated to reduce average number of customers out of power by up to 92% in the Woodlawn neighborhood of Pawtucket, a community with environmental justice indicators spanning energy, health, housing, legacy pollution, transportation, and workforce development.[27] Woodlawn was also identified as a particularly vulnerable neighborhood, and power outages a particular resilience concern in Pawtucket's 2020 *Community Resilience Building Workshop Summary of Findings*.[28] Locations 2 and 3 are anticipated to reduce average number of customers out of power by 12-37% in Woonsocket, which has health and workforce development justice indicators.[29] The City of Woonsocket identified "power outages to residential homes and businesses" and "low-income households' vulnerability due to power outages" as two infrastructure concerns and challenges in its 2020 *Community Resilience Building Workshop Summary of Findings*.[30]

The Project Team will rely on its prior experience with utility-scale storage (two demonstration projects in Rhode Island; one storage project for reliability in PPL Affiliate territory) and non-wires solutions (multiple requests for proposals in Rhode Island) to mitigate risks with procurement and operations. The Project Team lays out an extensive and thoughtful community engagement plan for this work in the Community Benefits Plan.

> **A replicable framework for investing in community-prioritized resilience**

The Project Team will develop and pilot a framework for incorporating community insight into planning and integrating non-customer funding to unlock investments with local non-resilience value. This "Community-Prioritized Resilience Investment Framework" ("the CPRI Framework") is envisioned as a process by which utility planners can defer to local communities (and their local knowledge and preferences) to prioritize investments such that total investment value is optimal for both parties (the process for developing and piloting the CPRI Framework is described in detail in the Community Benefits Plan). Providing a mechanism to include non-customer funding in investments also addresses the issue of scarce resources; non-customer funding bolsters the entire pot of resources that can be invested in utility projects without increasing energy burden for customers.

The Project Team anticipates funding three community-prioritized resilience projects. Table 3 summarizes cost share expectations for the three projects supported by federal funding and projects that follow the 60-month grant period. The third project will pair federal funding with customer funding requested through appropriate regulatory channels. The goal is to build up and test the CPRI Framework such that the Project Team can implement the CPRI Framework without federal funding following the 60-month grant period. The Project Team will require that a minimum of 40% of the funding allocated to the CPRI Framework supports project(s) that benefit members of a DAC(s). This carveout will fund at least one project.

[27] Tract Number 44007016400; CEJST
[28] https://riib.org/wp-content/uploads/2022/05/Pawtucket-_-Central-Falls-CRB-Summary-of-Findings-Report-October-2020_1.pdf
[29] Tract Number 44007018400; CEJST
[30] https://riib.org/wp-content/uploads/2023/01/Final-Woonsocket-Community-Resilience-Building-Summary-of-Findings-Report-October-2020.pdf

The CPRI Framework offers two important innovations: (1) demonstrating how utilities can operationalize "energy democracy" and (2) innovating on the application of 'Contributions in Aid of Construction' (CIAC) cost recovery mechanism. The City of Providence laid critical groundwork for Rhode Island to consider climate justice in its climate mandates by developing its *Climate Justice Plan* in collaboration with the Racial and Environmental Justice Committee of Providence.[31] A key recommendation of the *Climate Justice Plan* is "energy democracy," in which decision-making about energy and utility investments transforms from superficial, token engagement to deferring to communities and promoting community ownership.[32] The CPRI Framework operationalizes energy democracy by setting up a process where communities directly inform investment decision-making by prioritizing resilience investments that yield the most value for those communities. The CPRI Framework's cost share accounting mechanism is modeled from the proven CIAC mechanism. CIAC is commonly used to assess the costs of line extension for the requesting customer. The CPRI Framework extends the concept of CIAC in two novel ways: (1) the CIAC mechanism extends to support resilience investments and (2) the CIAC mechanism expands to collect cost share from a group of beneficiary customers rather than a single customer. These two innovations have the potential to unlock local investment opportunities that improve resilience and provide local resilience and non-resilience benefits. The deliverables associated with this work will maximize impact through replicability, which can lead to further investment, more benefits, greater resilience, and more innovation for customers across the nation. This work would not proceed but-for federal funding.

Replicability at Scale: This proposal is expected to reduce perceived risk for project deployment, lead to further deployment at scale, and lead to additional private sector investments. Perceived risk will be reduced through internal experience, case studies, industry communication, and real demonstration of technical feasibility, success, and impacts. Reduced risk can lead to increased implementation of innovative resilience investments and community engagement both within the Project Team and across utilities. Altogether, these investments are likely to build resilience, spur supplemental private funding, and strengthen the grid.

Workplan

Project Objectives: Make the grid STRONG on schedule, on budget, and equitably

The goal of the proposed STRONG investment is to improve energy resilience in response to specific priorities and through innovation in utility planning and cost recovery processes. In doing so, the Project Team will demonstrate a viable strategy to advance energy resilience, reduce energy burden, and operationalize energy democracy. In developing this proposal and workplan, the Project Team has the following project objectives:

1. Leverage the Project Team's collective expertise and strong stakeholder relationships to

[31] "The City of Providence's Climate Justice Plan." 2022. City of Providence and Racial and Environmental Justice Committee of Providence. https://www.providenceri.gov/sustainability/climate-justice-action-plan-providence/.
[32] Concept developed by Rosa González of Facilitating Power, in collaboration with Movement Strategy Center, in part drawing on content from a number of public participation tools, including Arnstein's Ladder of Citizen Participation and the Public Participation Spectrum created by the International Association for Public Participation." Adapted for this proposal from the Urban Sustainability Directors Network "From Community Engagement to Ownership." 2018. Urban Sustainability Directors Network. https://www.usdn.org/uploads/cms/documents/community_engagement_to_ownership_-_tools_and_case_studies_final.pdf.

develop a practical project implementation plan that results in successful project deployment and meaningful community engagement.
2. Defer to stakeholders with first-hand understanding to make sure plans for deployment, cost recovery, and ongoing operations work for all customers, with special focus on underrepresented customers in DACs.

The Project Team's collective expertise is described in the Qualifications section of this Technical Volume and supported by team member resumes. Descriptions of enhanced community engagement and the CPRI Framework are in the Community Engagement section of the Community Benefits Plan. The Project Team's workplan is described in depth below. There are several significant outcomes expected as a result of these proposed investments:

- Reliability improvements for 12 communities
- Benefits flow to at least 6 DACs
- $85,000,000 reduction in costs otherwise recovered from customers

The Project Team has designed its workplan and its reporting schedule to track progress toward these outcomes via SMART goals.

Technical Scope Summary: During the 60-month period of performance, the Project Team will implement a portfolio of steel-in-the-ground projects and develop and pilot a replicable framework for community-prioritized resilience investment. Together, these investments will strengthen the resilience of the power system to coastal storms and flooding and spur further replication and innovation in climate resilience.

Strategy to comply with Buy America requirements: *The proposal will involve the construction, alteration, maintenance and/or repair of public distribution and transmission utility infrastructure within the United States. While, for the purposes of this FOA, the Project Team, which is a for-profit entity as defined in the FOA, is not required to comply with the Buy America Act or the Build America, Buy America Act requirements ("Buy America" requirements) for the FOA infrastructure projects, RIE will exercise reasonable efforts, to the extent possible, to source materials within the United States, as available and appropriate, including, but not limited to, based on lead times.*

Work Breakdown Structure (WBS) and Task Description Summary: The Project Team divides its workplan into discrete performance periods aligned with Rhode Island's annual capital investment regulatory review requirements. Rhode Island's Revenue Decoupling Act[33] requires RIE to file an annual investment plan for "(1) capital spending on utility infrastructure; (2) operation and maintenance expenses on vegetation management; (3) operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and (4) any other costs relating to maintaining safety and reliability that are mutually agreed upon by the [Division of Public Utilities and Carriers] and [RIE]." This annual investment plan, called the *Electric Infrastructure, Safety, and Reliability Plan*, covers applicable spending for the period April 1 – March 30. Spending is reconciled on an annual basis as well, through the same plan and regulatory oversight. Quarterly compliance reports are also required to track progress and ensure accountability.

The Project Team developed its workplan to align with this annual cadence of regulatory filings, with the regulatory decision representing the go/no-go decision point between each

[33] http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.1.HTM

period of performance. The intent of this decision point is to adjust proposed spending down of federal funding to align with actual planned work and cost share. The Project Team views this structure as particularly advantageous for two reasons. First, having certain decisions about deployment schedules and spending on an annual basis mitigates risk of unspent federal funding. Second, the Rhode Island Public Utilities Commission (RIPUC) is required by statute to render a decision within 90 days, which mitigates the risk of delays and sliding schedules.[34]

End of Project SMART Goal: The End of Project SMART Goal is 100% installation of all resilience investments described in the Technical Description section on the Technical Volume, including three resilience investments prioritized by communities. The expected outcomes are the reliability improvements and customer cost reduction. To ensure progress toward the End of Project SMART Goal, the Project Team sets Annual Technical SMART Goals related to progress toward installation, detailed in Table 5.

Project Management: Throughout its workplan, the Project Team identifies the lead for each task and subtask, as well as key team members. The specific qualifications of these personnel are detailed in the Qualifications section of the Technical Volume and supported by their resumes (included in application materials). Kathy R. Castro (Principal Investigator), Director of Asset Management and Engineering for RIE, along with planning and subject matter experts Caleb George and Jed Ferris will lead all installation tasks for distribution investments, leveraging their decades of combined technical and team management experience. Joseph B. Lookup, Director of Asset Management and Planning for PPL, will lead transmission installation. Key supporting team members include leads on permitting, procurement, and project management. Dr. Carrie A. Gill, Senior Manager of Regulatory Strategy for RIE, will coordinate stakeholder engagement activities, including the CPRI Framework, leveraging the capabilities of RIE's External Affairs team. The Project Team includes a specific Task for project management, led by Castro, to demonstrate the organization with which RIE and PPL approach project management. This project management task will support all critical handoffs and interdependencies. Critical interdependencies arise when stakeholder feedback needs to flow to/from technical teams. The WBS was developed such that all critical handoffs remain within the same team, under the same lead, to ensure success. In such situations, task leads will be well prepared to communicate via a biweekly internal meeting. Furthermore, all members of the Project Team work closely together on a wide variety of workstreams, so the Project Team will build on experience and prior lessons learned to ensure successful handoffs and interdependencies.

There are two notable characteristics of the Project Team's project management strategy: First, the Project Team differentiates between internal project management and check-ins with DOE; this demonstrates the inherent motivation RIE and PPL have to be successful regardless of external pressure and should signal to reviewers the commitment of the Project Team to ensuring success. Second, the Project Team plans for quarterly updates to RIE and PPL leadership at the highest levels, including RIE's President and PPL's Chief Executive

[34] Furthermore, the Project Team will be able to adjust the workplan to its regulatory schedule during contract negotiations for complete alignment; this flexibility allows the Project Team to hit the ground running regardless of when award selection is made; thereby mitigating inherent risk that comes with uncertainty about start date for period of performance when crafting this application.

Officer and Chief Operating Officer; this level of communication showcases the importance of this work to future business strategy and ensures federal funding is used responsibly and meaningfully.

The Project Team has developed its workplan, using the above objectives, to successfully achieve key outcome-based and SMART milestones with the flexibility needed to stay on budget and on schedule. Resulting tasks and subtasks are described below in relation to milestones, deliverables, and go/no-go decision points, and disaggregated by budget period.

| Table 2: Tasks, subtasks, deliverables, and milestones

Task 0: Project Management and Planning (Lead: Castro)

Subtask 0.1: Project Management Plan (Lead: Castro) – Month 1
Develop PMP within first 30 days of the award; the PMP will include an explicit workplan for filing a proposal with the RI PUC on reduction of cost recovery due to availability of federal funding; *Deliverable*: Project Management Plan

Subtask 0.2: NEPA Compliance (Lead: Castro) – Months 1-3
Determine applicability and provide documentation for NEPA compliance

Subtask 0.3: Cybersecurity Plan (Lead: Randle) – Months 1-60
The CSP shall be revised and resubmitted as often as necessary, during the course of the project, to capture any major/significant changes; *Deliverable*: Cybersecurity Plan

Subtask 0.4: Continuation Briefings (Lead: Castro) – Months 1-60
Brief DOE on roughly an annual basis to explain the plans, progress and results of the technical effort; describe performance; *Deliverable*: Pre-Continuation Briefing Documents

Task 1: Mitigate Substation Flooding (Lead: George)

Subtask 1.1: Engineering, Design, and Regulatory (Lead: George) – Months 1-48
Refine engineering design; include project specifications and budget in annual Electric ISR filings

Subtask 1.2: Land Acquisition and Permitting (Lead: Glenning) – Months 13-36
Acquire parcel of land proximal to existing substation to use for compensatory storage; File for and receive permits including state, environmental, and municipal; *Milestone*: Land acquired

Subtask 1.3: Detailed Engineering Design (Lead: George) – Months 25-36
Includes full specifications and technical detail; *Milestone*: Green light for construction

Subtask 1.4: Procurement, Construction, Commissioning, Inspection (Lead: Glenning) – Months 25-54
Procure all equipment required; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: Substation energized

Subtask 1.5: Case Study (Lead: Gill) – Months 54-56
Develop case study on flood mitigation using compensatory storage; *Deliverable*: case study

Task 2: Strengthen Substation Resilience and Accommodate Electrification (Lead: George)

Subtask 2.1: Engineering, Design, and Regulatory (Lead: George) – Months 1-36
Refine engineering design; include project specifications and budget in annual Electric ISR filings

Subtask 2.2: Permitting (Lead: Glenning) – Months 13-18
File for and receive permits including state, environmental, and municipal

Subtask 2.3: Detailed Engineering Design (Lead: George) – Months 13-24
Includes full specifications and technical detail; *Milestone*: Green light for construction

Subtask 2.4: Procurement, Construction, Commissioning, Inspection (Lead: Glenning) – Months 25-42
Procure all equipment required; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: Substation energized

Task 3: Accelerate Feeder Resilience (Lead: George)

Subtask 3.1: Engineering, Design, and Regulatory (Lead: George) – Months 1-36
Refine engineering design; include project specifications and budget in annual Electric ISR filings

Subtask 3.2: Permitting (Lead: Glenning) – Months 13-24
File for and receive permits including state, environmental, and municipal

Subtask 3.3: Detailed Engineering Design (Lead: George) – Months 13-34
Includes full specifications and technical detail; *Milestone*: Green light for construction

Subtask 3.4: Procurement, Construction, Commissioning, Inspection (Lead: Glenning) – Months 25-48
Procure all equipment required; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: Substation energized

Task 4: Relocate Coastal Feeders Underground (Lead: George)

Subtask 4.1: Misquamicut (Lead: George) – Months 13-36
Refine engineering design; include project specifications and budget in annual Electric ISR filings; file for and receive permits including state, environmental, and municipal; detailed engineering design including full specifications and technical detail; procure all equipment needed; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: Green light for construction; *Milestone*: Feeder energized

Subtask 4.2: Oakland Beach (Lead: George) – Months 25-48
Refine engineering design; include project specifications and budget in annual Electric ISR filings; file for and receive permits including state, environmental, and municipal; detailed engineering design including full specifications and technical detail; procure all equipment needed; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: Green light for construction; *Milestone*: Feeder energized

Task 5: Address Wind-Driven Outages (Lead: George)

Subtask 5.1: Engineering, Design, and Regulatory (Lead: George) – Months 1-36
Refine engineering design; include project specifications and budget in annual Electric ISR filings

Subtask 5.2: Permitting (Lead: Glenning) – Months 13-24
File for and receive permits including state, environmental, and municipal

Subtask 5.3: Detailed Engineering Design (Lead: George) – Months 13-34
Includes full specifications and technical detail; *Milestone*: greenlight for construction

Subtask 5.4: Procurement, Construction, Commissioning, Inspection (Lead: Glenning) – Months 25-48
Procure all equipment required; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: feeder energized

Task 6: Relocate Transmission Line Underground (Lead: Lookup)

Subtask 6.1: Detailed Engineering (Lead: Lookup) – Months 1-12
Geotechnical analysis; engineering design; *Milestone*: technical feasibility

Subtask 6.2: Funding/Financing (Lead: Ucci) – Months 1-12
Work with community partners to secure external funding; *Milestone*: financial feasibility

Subtask 6.3: Permitting and Regulatory (Lead: Lookup) – Months 12-30
Includes state, environmental, regulatory, and municipal approvals; *Milestone*: greenlight for construction

Subtask 6.4: Procurement, Construction, Commissioning, Inspection (Lead: Glenning) – Months 31-60
Procure all equipment required; construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: line energized

Task 7: Utility-Scale Storage for Resilience (Lead: Ferris)

Subtask 7.1: Location 1 Pawtucket (Lead: Ferris) – Months 13-36
Refine engineering design; include project specifications and budget in annual Electric ISR filings; identify (and acquire if needed) parcel of land; file for and receive permits including state, environmental, and municipal; detailed engineering design including full specifications and technical detail; procure all equipment needed (includes Request for Proposals for battery energy storage system); construct according to detailed engineering design and in alignment with permits and approvals; commission; inspect; *Milestone*: land identified; *Milestone*: green light for construction; *Milestone*: storage energized

Subtask 7.2: Location 2 Woonsocket (Lead: Ferris) – Months 25-48
Same as Subtask 7.1; *Milestone*: land identified; *Milestone*: green light for construction; *Milestone*: storage energized

Subtask 7.3: Location 3 Woonsocket (Lead: Ferris) – Months 37-60
Same as Subtask 7.1; *Milestone*: land identified; *Milestone*: green light for construction; *Milestone*: storage energized

Task 8: Community Prioritized Resilience Investment (CPRI) Framework (Lead: Gill)

Subtask 8.1: Develop CPRI Framework (Lead: Gill) – Months 1-12
Identify stakeholders to participate in the CPRI Framework Stakeholder Group; convene the CPRI Framework Stakeholder Group at least six times; draft and refine CPRI Framework for piloting; coordinate with Constable, Johnson, Castro, Schuster, Grant, Evans, Bonenberger throughout development; *Deliverable*: CPRI Framework Stakeholder Group membership list, meeting materials and minutes, CPRI Framework

Subtask 8.2: Identify Pilot Communities (Lead: Gill) – Months 1-24
Identify three communities (i.e. municipalities) that commit to piloting the CPRI Framework; at least one community must advance a resilience investment that directly benefits a disadvantaged community; *Deliverable*: Letters of Commitment

Subtask 8.3: Pilot Project #1 (Lead: Gill) – Months 13-48
Liaise with pilot community, community managers (Afonso, Albanese, Spangler, Stasiuk), and engineers (Constable, George, Ferris) to identify resilience needs and solutions, educate and advise community members on tradeoffs of potential solutions, select and implement priority solution; *Milestone*: greenlight for construction; *Milestone*: pilot project #1 energized

Subtask 8.4: Pilot Project #2 (Lead: Gill) – Months 18-54
Same as Subtask 8.3; *Milestone*: greenlight for construction; *Milestone*: pilot project #2 energized

Subtask 8.5: Pilot Project #3 (Lead: Gill) – Months 25-60
Same as 8.3, plus: advance solution through an annual Electric ISR regulatory process, implement solution; *Milestone*: regulatory approval; *Milestone*: greenlight for construction; *Milestone*: pilot project #3 energized

Subtask 8.6: Develop Final Report (Lead: Gill) – Months 54-60
Describe the CPRI Framework, including insights, lessons learned, business implications, recommendations for future research, and steps for replicability; *Deliverable*: final report

Task 9: Enhanced Community Engagement (Leads: Afonso and Albanese)

Subtask 9.1: Enhanced Community Engagement (Leads: Afonso and Albanese) – Months 1-60
Lead enhanced proactive community engagement for Tasks 1-8 throughout the grant period; liaise with external affairs team (Schuster, Afonso, Albanese, Spangler, Stasiuk, Grant, Ucci, Gill) and abutter relations manager; liaise internally to share insights and lessons learned

Subtask 9.2: Develop Case Study (Lead: Gill) – Months 58-60
Work with community managers (Afonso, Albanese, Spangler, and Stasiuk), abutter relations manager, regulatory affairs (Grant), and government affairs (Ucci) to describe the enhanced community engagement pilot, including insights, lessons learned, business implications, and steps for replicability; *Deliverable*: case study

Task 10: Project Management (Lead: Castro)

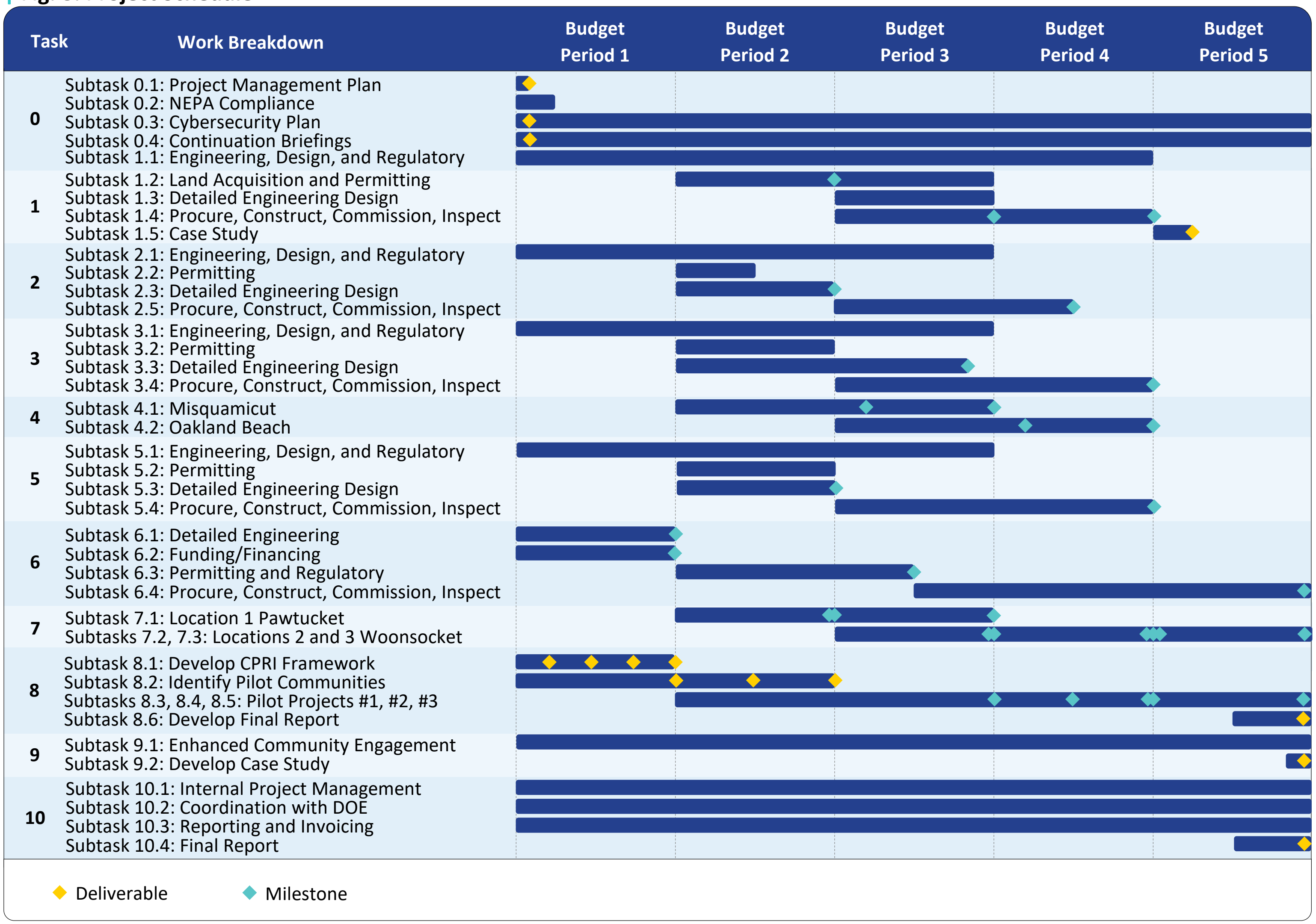
Subtask 10.1: Internal Project Management (Lead: Begnal) – Months 1-60
Biweekly internal meetings with the Project Team to assess progress, identify and resolve issues, share insights, and make progress; management of annual regulatory filings with support from Begnal; quarterly internal report outs to RIE and PPL leadership (Bonenberger, PPL CEO, PPL COO, PPL CIO, PPL VP and Chief DEI Officer)

Subtask 10.2: Coordination with DOE (Lead: Begnal) – Months 1-60
Meetings with DOE grant manager, staff, and other DOE-sponsored events to share insights and progress; providing briefings; adjustments to the workplan due to annual approval cycle of Electric ISR Plan at each go/no-go decision point

Subtask 10.3: Reporting and Invoicing (Lead: Grzesiuk) – Months 1-60
Quarterly financial and performance reporting; other reporting as required

Subtask 10.4: Final Report (Lead: Gill) – Months 54-60
Develop the final report to include all case studies, additional insights, recommendations for future research and funding, best practices and lessons learned from community engagement, and steps for replicability; please note that the Project Team will share drafts of all case studies and the final report with DOE staff for review prior to finalization; *Deliverable*: Final Report

Fig. 8: Project Schedule



Milestones Summary and Go/No-Go Decision Points: Milestones specify community engagement for each quarter of the 60-month performance period. As detailed in the Community and Labor Engagement section of the Community Benefits Plan, the Project Team commits to two innovative strategies for engagement:

(1) Enhanced Community Engagement: Piloting advanced and proactive community engagement for communities and stakeholders of each of the resilience investments
(2) CPRI Framework: Engaging with communities during the planning process to identify resilience needs, prioritize resilience solutions, and leverage non-federal funding

This engagement is further described within Tasks 8 and 9, below. The intent of calling out engagement as its own task is not to signal that the engagement will be isolated, but rather to highlight the emphasis the Project Team places on ensuring this engagement is done properly. Leads for engagement will work hand-in-hand with leads for installation tasks (Tasks 1-7) throughout the period of performance to ensure full integration of engagement with installation.

Table 5: Project Schedule

Event	Timing	Description/Expected Outcome
BP1	Month 1-12	• Engineering, design, and regulatory for Tasks 1-3, 5 complete • Detailed engineering for transmission line complete • CPRI Framework developed
M1.1	Month 3	• Deliverable: Project Management Plan • CPRI Framework Stakeholder Group (at least 10 stakeholders) ○ Deliverable: CPRI Framework Stakeholder Group Membership List • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M1.2	Month 6	• At least 3 CPRI Framework Stakeholder Group meetings ○ Deliverable: Meeting Materials and Minutes • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M1.3	Month 9	• At least 3 CPRI Framework Stakeholder Group meetings ○ Deliverable: Meeting Materials and Minutes • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M1.4	Month 12	○ Deliverable: CPRI Framework ○ Milestone: Task 6 technical feasibility confirmed • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
Annual SMART Milestones		• *Annual SMART Technical Milestone*: 2% budget spent • *Annual SMART DEIA Milestone*: total number of engagement touchpoints; total reach of engagement touchpoints
Go/No-Go	Month 12	• Regulatory approval of FY 2025 Electric ISR Plan • At least one CPRI community identified
BP2	Month 13-24	• Three CPRI communities identified • Six milestones met
M2.1	Month 15	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M2.2	Month 18	○ Milestone: Task 6 financial feasibility confirmed • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes

M2.3	Month 21	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M2.4	Month 24	○ Milestone: Task 7.1 land acquired ○ Milestone: Green light for Task 2, 3, 4.1, 5, 7.1 construction ○ Deliverable: Letters of commitment from CPRI communities • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
Annual SMART Milestones		• *Annual SMART Technical Milestone* criteria: 8% budget spent • *Annual SMART DEIA Milestone*: total number of engagement touchpoints; total reach of engagement touchpoints, year-over-year changes
Go/No-Go	Month 24	• Regulatory approval of FY 2026 Electric ISR Plan • Regulatory and permitting approvals for Task 6
BP3	Month 25-36	• Task 4.1 100% complete • Task 7 33% complete • Task 8 projects 33% greenlight for construction
M3.1	Month 27	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M3.2	Month 30	○ Milestone: green light for Task 6 construction • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M3.3	Month 33	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M3.4	Month 36	○ Milestone: Task 7.2 land acquired ○ Milestone: Task 1, 4.2, 8.3 green light for construction ○ Milestone: Task 4.1, 7.1, 7.2 energized • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
Annual SMART Milestones		• *Annual SMART Technical Milestone*: 30% budget spent • *Annual SMART DEIA Milestone*: total number of engagement touchpoints; total reach of engagement touchpoints, year-over-year changes
Go/No-Go	Month 36	• Regulatory approval of FY 2027 Electric ISR Plan
BP4	Month 37-48	• Task 2, 3, 4.2, 5 100% complete • Task 7 67% complete • Task 8 projects 100% greenlight for construction
M4.1	Month 39	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M4.2	Month 42	○ Milestone: Task 2 energized ○ Milestone: Task 8.4 green light for construction • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M4.3	Month 45	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M4.4	Month 48	○ Milestone: Task 7.3 land acquired ○ Milestone: Task 3, 4.2, 5, 7.2, 7.3, 8.3 energized ○ Milestone: Task 8.5 greenlight for construction • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
Annual SMART Milestones		• *Annual SMART Technical Milestone*: 95% budget spent • *Annual SMART DEIA Milestone*: total number of engagement touchpoints; total reach of engagement touchpoints, year-over-year changes

Go/No-Go	Month 48	• Regulatory approval of FY 2028 Electric ISR Plan
BP5	Month 49-60	• Task 1, 7, 8 100% complete
M5.1	Month 51	• Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M5.2	Month 54	○ Milestone: Task 1, 8.4 energized • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M5.3	Month 57	• Deliverable: Case study on flood mitigation using compensatory storage • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes
M5.4	Month 60	○ Milestone: Task 6, 7.3, 8.5 energized ○ Deliverable: final report on CPRI framework ○ Deliverable: final project report • Enhanced Community Engagement touchpoint ○ Deliverable: description of touchpoint, materials, notes ○ Deliverable: case study on enhanced community engagement
Annual SMART Milestones		• *Annual SMART Technical Milestone*: 100% budget spent • *Annual SMART DEIA Milestone*: total number of engagement touchpoints; total reach of engagement touchpoints, year-over-year changes

Notes: BP = Budget Period; MX.Y = Milestone corresponding to BP X, quarter Y; Go/No-Go = Go/No-Go Decision Point. RIPUC = Rhode Island Public Utilities Commission. The Electric ISR Plan is RIE's annual capital investment plan covering April 1 through March 30; each plan is denoted with an FY (fiscal year) where that year corresponds to the fourth quarter of the plan. For example, FY 2024 Electric ISR Plan corresponds to planned investments April 1, 2023-March 30, 2024. Milestones regarding greenlighting of construction will be evinced via approval of related Electric ISR Plan (Tasks 1-5, 7, 8) and/or relevant regulatory and permitting approvals to be determined a priori.

Any project changes will be handled swiftly and appropriately. Changes that arise due to annual approval cycles for RIE's Electric ISR Plan will be incorporated into the workplan via Subtask 10.2 in complete coordination with DOE staff. Changes that arise due to unforeseen events will be discussed and vetted both internally (Subtask 10.1) and with DOE staff (Subtask 10.2) as soon as those unforeseen events are known.[35]

The Project Team does not foresee any risks other than those described within this application. Risk mitigation strategies specific to reach risk are described throughout this application. The Project Team also views its stakeholder engagement plan as a risk mitigation strategy: transparency, accountability, and stakeholder insights will ensure work is completely efficiently and effectively throughout the period of performance. The Project Team's overall risk management strategy is throughout the entire lifecycle of the project: preemptive mitigation, advanced notice via monitoring and reporting, close and constant communication, transparency, flexibility, and feedback loops.

Technical Resources and Qualifications

Team Qualifications: Demonstrated commitment to resilience, innovation, and engagement

The Project Team brings many valuable qualifications, experiences, and capabilities to

[35] Please note that no unforeseen events are predicted at this time; all known risks have been described in this application packet (specifically concentrated within the Technical Description section of the Technical Volume) to the best of the Project Team's ability.

this proposal.[36] Importantly, every member of the Project Team is dedicated to improving power resilience, and their diverse backgrounds and expertise will ensure that the implementation of the proposed investments would be carefully managed to yield successful outcomes. The Project Team has extensive experience in similarly complex capital investment portfolios, partnerships, and grant implementation. On an annual basis, RIE conducts modeling, planning, filing for regulatory approval, and implementation of a substantial portfolio of capital investments. These investments include a large number of projects that enhance resilience of the distribution system (see *Report on Resilience Investments*), and implementation is consistently on time and on budget. RIE has also demonstrated its commitment to innovation in distribution grid planning, including through its procurement program for non-wires solutions[37], its exploration of integrated grid planning[38], its data-driven grid modernization modeling[39], and its participation in prior DOE-funded initiatives[40]. These examples demonstrate RIE's capabilities to not only carry out large portfolios of investment, but also to be a productive team member, promote replicable and impactful innovations, and engage with communities and stakeholders. PPL's and RIE's existing equipment and facilities are sufficient to facilitate successful completion of this project; no new equipment or facilities are needed nor proposed as part of this project.[41]
Examples of prior resilience work include:
Coastal undergrounding at Sachuest Point, Middleton: RIE buried approximately 7,300' of overhead electric distribution with an underground distribution system.
Coastal undergrounding at Watch Hill, Westerly: In collaboration with the Watch Hill Conservancy, RIE successfully completed the conversion of overhead wiring to underground wiring, converting overhead distribution.
Substation flood mitigation: RIE completed the replacement and elevation of substation equipment that was damaged during a major flood in 2010. During this time, water levels reached a peak level of about 28 inches above grade at the Hope 15 Substation. Inside the control building, flood water reached a peak level of 21", which partially submerged the station battery and several relays.
Substation flood mitigation: RIE completed the elevation of substation equipment above flood levels to address related damage at the Pontiac Substation, and to reduce the risk of future flood damage. In March 2010, flood waters impacted the station, with waters levels at approximately 5' in the substation yard and at approximately 4' inside the control house; this event damaged most of the equipment in the substation yard and inside the control house.
Substation flood mitigation*:* RIE completed the elevation of substation equipment above flood levels to reduce the risk of flood damage at the Riverside Substation.

[36] The Project Team is not requesting technical services from DOE/NNSA FFRDCs.
[37] See for example https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Opportunities
[38] RIE is a team member of Rhode Island Office of Energy Resource's current effort to explore the value of incorporating hyper-local knowledge and preferences into distribution system planning; the project team also includes Lawrence Berkeley National Lab and Regulatory Assistance Project (both supported by DOE) and the Town of Johnston.
[39] See https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/2256-RIE-Book2-%20GMPlan.pdf
[40] RIE participated in the DOE-funded Solar Energy Innovation Network 2019-2022: https://www.nrel.gov/docs/fy22osti/81960.pdf
[41] The Project Team is not requesting technical services from DOE/NNSA FFRDCs.

Substation flood mitigation: RIE completed the elevation of substation equipment above flood levels to address flood related damage and reduce the risk of future damage at the Warwick Mall Substation. Flooding in 2010 resulted in significant equipment damage at this substation, which is located approximately 18" below the flood elevation. Without this work, equipment would be at high risk of future flooding.

Key Team Members: Within the Project Team, the following individuals would bring their deep and multidisciplinary knowledge to deliver these proposed investments and intended outcomes. Roles, time commitments, and relevant expertise and experience of these team members is described below in relation to the proposed work at hand. Resumes for all of the following key team members are included in the application package.

Kathy Castro (PI) – Director of Distribution Planning and Asset Management, RIE

Castro is the principal investigator on this proposal and serves as both the technical point of contact and the lead project manager. Castro will specifically oversee Project Management (Task 10) and provide technical guidance and leadership on all distribution system work (Tasks 1-5, 7-8). Castro brings nearly two decades of utility industry experience in analysis and design, project management, corporate management, marketing, and business development. Furthermore, Castro's role with overseeing all distribution investments will ensure full integration with the investments proposed herein and all other investments occurring as normal course of business; thereby ensuring efficient work schedules, adequate and capable workforce, and synergistic activities in the field. Castro will allocate 10% of her time to this work over the 60-month period of performance.

Ryan Constable – Manager; Distribution Planning and Asset Management, RIE

Constable will provide critical engineering support for the CPRI Framework (Task 8). Constable has nearly two decades of utility planning experience and is a recognized expert in the field. Constable was a key team member in the 2019-2022 Solar Energy Innovation Network Rhode Island Team, and he is the lead engineer exploring integrated grid planning with a local municipality. Constable will allocate 200 hours of his time to this work.

Caleb George – Principal Engineer, Distribution Planning and Asset Management, RIE

George will lead all flood mitigation and hardening distribution system projects (Tasks 1-5). His experience with enhancing resilience of the electric grid makes George a clear fit in both expertise and experience for this role. George will allocate 500 hours of his time to this work.

Gerald Ferris – Supervisor Interconnections; Distribution Planning and Asset Management, RIE

Ferris will lead the three utility-scale storage for resilience projects (Task 7). Ferris is the lead engineer overseeing RIE's two energy storage demonstration projects, so his experience will capture lessons learned to ensure smooth deployment and effective operation. Ferris will allocate 200 hours of his time to this work.

Nicole Begnal – Electric ISR Plan Manager, RIE

Begnal will lead internal project management (Subtask 10.1) and coordination with DOE (Subtask 10.2) and will support Grzesiuk with reporting (Subtask 10.3). Begnal will also provide critical support on regulatory filings for all distribution projects (Tasks 1-5, 7-8). Begnal's position already requires her to collaborate closely with Grzesiuk to not only track performance and spending of projects included in the Electric ISR Plan, but also to work with planners (Castro, Constable, George, Ferris) and project managers (Glenning) to develop and defend practical capital investment plans. Leveraging her existing approach to collaboration, Begnal will allocate 570 hours to this work over the 60-month period of performance.

Beth Johnson – Director of Regulatory Affairs, PPL

Johnson will provide regulatory expertise in support of the CPRI Framework (Task 8), as well as general support to ensure federal funding is accounted for in ratemaking. Johnson oversees a team of regulatory analysts and has the capability and expertise to assist in developing a practical CPRI Framework with innovative application of Contribution in Aid of Construction (CIAC). Johnson will allocate 200 hours to this project.

Brian Grzesiuk – Senior Financial Manager, RIE

Grzesiuk is the lead financial manager and business point of contact for this proposal. In leading Subtask 10.3, Grzesiuk will leverage his existing work with tracking performance and spending for capital investments to ensure quality and timely reporting. Grzesiuk's five-year tenure with RIE has led to his fluency in both financial and performance reporting. Grzesiuk leads a team of five, responsible for budgeting and forecasting for operating and capital expenditures, long term business planning, and supporting the strategic, operational, and financial decision making for the Electric Business. Grzesiuk will allocate 380 hours to this project over the 60-month period of performance.

Joe Lookup – Director of Transmission Asset Management and Planning, PPL

Lookup will lead all transmission projects (Task 6). He leads a team responsible for strategy and oversight of transmission and substation assets, and has experience in transmission planning, asset strategy, new project development, innovation, and technology. Lookup will allocate 1,000 hours to this project.

Dan Glenning – Director of Project Management, RIE

Glenning will lead project management for all distribution projects (Tasks 1-5, 7-8). Glenning will allocate 700 hours to this project.

Jacques Afonso, Marisa Albanese, Lori Spangler, Paul Stasiuk – Community Managers, RIE

Afonso, Albanese, Spangler, and Stasiuk are the team of community managers at RIE that serve every community served by the utility. Together, this team has decades of combined experience demonstrating the strong and enduring relationships with key stakeholders in RI. This team will play an essential role in piloting enhanced community engagement (Task 9) regarding all facets of the proposed work, including before, during, and after project construction (Tasks 1-7) as well as throughout the development and pilot of the CPRI Framework (Task 8). They will allocate a total of 4,000 hours to this project.

Angie Evans – Vice President and Chief DEI Officer, PPL

Evans will provide support for and oversight of all work related to the Community Benefits Plan, including but not limited to progressing DEIA actions and reporting on annual SMART DEIA milestones. In Evan's role as VP and Chief DEI Officer, she is responsible for advancing PPL's enterprise-wide diversity, equity and inclusion strategy and commitments. Evans will focus her efforts on joining quarterly leadership meetings and supporting the efficacy of the Enhanced Community Engagement pilot (Task 9). She will allocate 100 hours to this project.

Carrie Gill, PhD – Senior Manager of Electric Regulatory Strategy for External Affairs, RIE

Gill will lead the CPRI Framework (Task 8) as well as all deliverables (Subtasks 1.7, 9.2, and 10.4), in addition to providing general support for project management. Gill's extensive experience with project management of federal grants, state and federal policy expertise, and experience in the industry will ensure deliverables meet the dual needs of supporting internal learnings and maximizing external impact through replicability. She will allocate 1,000 hours for this work.

Kate Grant – Senior Manager of Regulatory Affairs, RIE

Grant will support Enhanced Community Engagement (Task 9), support development of the CPRI Framework (Subtask 8.1), and provide general support for project management particularly with ongoing updates to regulatory staff. Grant will allocate 200 hours.

Nicholas Ucci – Director of Government Affairs, RIE

Ucci will support Enhanced Community Engagement (Task 9) and will provide general support for project management, particularly with ongoing updates to state legislators and RI's congressional delegation. He will allocate 200 hours to this project.

Brian Schuster – Senior Director of External Affairs, RIE

Schuster will provide general support, leadership, and guidance to this project, especially regarding stakeholder, community, and labor engagement. Schuster leads the management of public relations and communications between RIE and the state's legislative, regulatory, and community stakeholders. He will allocate 100 hours to this project.

Chris Randle – Vice President of Cybersecurity, PPL

Randle will lead all cybersecurity work associated with this project. Randle's vast experience demonstrates his impressive qualifications for this role. He has more than 20 years of experience in cybersecurity, creating and executing strategies that protect Fortune 500 companies from advanced cyber threat activity. In his current role, he is responsible for the cyber safety of all PPL operating companies, including RIE. He focuses on creating and managing the strategic success of cybersecurity in the organization, including the following areas: Identity and Access Management, Privileged Access Management, Cloud Security, Risk Management, Incident Response, Cyber Monitoring, ICS/OT Security, Cyber Awareness and Training, Cyber Engineering, Product Security, Vulnerability Management, CIP Compliance and SOX Compliance. He will allocate 200 hours to this work.

David Bonenberger – President, RIE

Bonenberger will serve as the lead decision-maker and provide general support, leadership, and guidance to this project. Bonenberger's prior roles bridge the PPL and RIE teams: Prior to RIE, Bonenberger held the roles of VP of Operations Integration at PPL, through which he led the integration of RIE and PPL. He also held the role of VP of Transmission and Substations through which he supported the PPL's grid modernization efforts. Bonenberger has held various positions in the corporate audit, financial, customer service and operations departments at PPL, and his utility experience spans nearly four decades. Bonenberger serves as Chair Emeritus of the Edison Electric Institute's National Response Executive Committee. He will allocate 100 hours to this project.

Al LaBarre – Vice President of Electric Operations, RIE

LaBarre will provide support, leadership, and guidance to this project, leveraging his nearly 30 years of experience in the electric industry. He will allocate 100 hours to this project.

Smart Grid for Smart Decarbonization:
Deploying advanced IT/OT to meet nation-leading clean energy mandates

FOA Number: DE-FOA-0002740
BIL – Grid Resilience and Innovation Partnerships (GRIP)
Topic Area 2: Smart Grid Grants (BIL section 40107)

Team Member Organizations
The Narragansett Electric Company d/b/a Rhode Island Energy, Prime Applicant
PPL Services Corporation, Team Member

Technical Point of Contact
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Project Location
State of Rhode Island

Notice of Restriction on Disclosure and Use of Data:
Tab a: Personnel, Tab b: Fringe, Tab d: Equipment, and Tab f: Contractual of the Budget Justification Workbook of this document may contain business sensitive, trade secrets, proprietary, or otherwise confidential information that is exempt from public disclosure. Such information shall be used or disclosed only for evaluation purposes or in accordance with a financial assistance agreement between the submitter and the Government. The Government may use or disclose any information that is not appropriately marked or otherwise restricted, regardless of source. [End of Notice].

Rhode Island Energy™
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Project Overview

Background: Smart grid investment needed for safe, reliable, affordable decarbonization

Clean, distributed energy resources and strategic electrification are necessary to mitigate climate change, but such investments are already creating new operational complexities for utilities across the country. With existing electric infrastructure, operators need adequate tools and technology to manage the grid and shifting dynamics of energy flows across it. Indeed, many grid operations are still conducted manually and supported by hand calculations. These methods will no longer be viable as increasing levels of Distributed Energy Resources (DER) require more frequent and flexible grid adjustments.

Project Goal: In this proposal, prime applicant and the grant recipient Rhode Island Energy (RIE) and team member and RIE affiliate and services company PPL Services Corporation (PPL) (together referred to as "the Project Team"), propose a comprehensive suite of information technology (IT) and operational technology (OT) to catalyze the unified *Smart Grid for Smart Decarbonization* concept to achieve the most advanced electric power system (EPS) in the nation, in the state with one of the most aggressive climate and clean energy mandates in the nation.

While each of these smart IT and OT systems independently offer value, their integration leads to synergies. The highly granular data coming from proposed investments in advanced reclosers, smart digital relays, and smart capacitors and regulators via the fiberoptic communications backbone is ingested and analyzed by Advanced Distribution System Management (ADMS) and Advanced Energy Management (AEMS; on the transmission system) software, which returns optimized directives to the OT devices. The centralized Asset Hub data system and an updated and integrated Geographic Information System (GIS) that represents a Digital Twin of the grid provide supporting business and planning optimization complementary to the ADMS and AEMS. The result is smarter use of RIE's existing grid as Rhode Islanders interconnect DER, electrify transportation and heating, and expect more from a 21st century EPS.

Rhode Island is an advantageous location for this work because of its nation-leading clean energy and climate mandates, its rich history of stakeholder engagement in grid modernization planning, and the commitment and experience of its primary utility. These factors put Rhode Island at the forefront of need, readiness, and capability for demonstrating a technology pathway to meet global climate challenges safely, reliably, and affordably. Rhode Island boasts one of the most aggressive decarbonized electricity mandates in the nation. Following extensive economic and energy analysis,[1] Rhode Island strengthened its Renewable Energy Standard in 2022, requiring the state to reach 100% renewable electricity by 2033.[2] Furthermore, RI's landmark 2021 Act on Climate[3] sets statewide, economy-wide greenhouse gas emissions mandates achieving net-zero in 2050, guaranteeing that transportation and thermal sectors will decarbonize alongside the electric sector. The state's *2022 Update* to its

[1] "The Road to 100% Renewable Electricity by 2030 in Rhode Island." 2020. https://energy.ri.gov/renewable-energy/100-percent-renewable-electricity-2030

[2] Chapter 26 Renewable Energy Standard. 2022. Vol. R.I. Gen. Laws. § 39-1-2 http://webserver.rilegislature.gov/Statutes/TITLE39/39-26/INDEX.htm

[3] 2021 Act on Climate (Rhode Island General Laws 42-6.2)

2016 Greenhouse Gas Emissions Reduction Plan[4] recognizes electrification as a proven and priority decarbonization strategy; this is supported by analyses and recommendations from the state's 2020 *Heating Sector Transformation*[5] and 2021 *Electrifying Transportation*[6] reports.

Recognizing the changing needs of the EPS, Rhode Island state agencies convened stakeholders, including RIE, to develop RI's 2017 *Power Sector Transformation*[7] Report. This evolved into a robust, multi-year (2018-2022) stakeholder process to develop and refine RIE's Advanced Metering Functionality Business Case (filed for regulatory review in November 2022) and Grid Modernization Plan (GMP; filed December 2022). Stakeholders representing environmental, consumer, supplier, policy, and regulatory interests heavily informed the extensive modeling that underlies RIE's proposed investments. The State's *2022 Update* to the *2016 Greenhouse Gas Emissions Reduction Plan* underscores the importance of grid modernization by calling out these investments as a priority action for the electric sector.[8] For a state with nation-leading climate and clean energy mandates, these investments will provide more than just local benefits – they will <u>demonstrate to other utilities and states that safe, affordable, reliable deep decarbonization at scale is possible.</u>

DOE Impact: <u>This work will not proceed at this pace or scale without federal funding</u>. Federal funding will accelerate investment in – and benefits from – the proposed IT/OT by up to two years and will expand the scope of smart IT investments to include Asset Hub and Digital Twin. The entirety of proposed investments will provide direct energy benefits to all RIE customers through improved reliability, quicker and less costly interconnections for DER, and faster deployment of electric vehicle (EV) charging stations at scale. Without federal funding, 100% of proposal costs[9] will be recovered from customers; if selected, federal funding will go directly to reducing costs for all Rhode Island customers. With the current macroeconomic landscape and historically high energy supply costs across New England, federal funding is also likely to expand the scale at which this investment occurs. Furthermore, the Project Team's proposed cost share (80% of total project costs) signifies the importance of the proposed work and grows the value of federal funding. The OT investments included in this proposal are scalable, and RIE may not be able to fund the full scale of investments in the timeframe targeted without federal funding.

Community Benefits: First, 100% of federal funding will directly reduce customer cost recovery. Second, the Project Team will continue RI's legacy of meaningful engagement through (1) continuing engagement through the Power Sector Transformation Advisory Group, (2) collaboration with stakeholders to launch a program to support more efficient integration of

[4] 2022 Draft Update to the 2016 Greenhouse Gas Emissions Reduction Plan "Act on Climate." 2022. https://climatechange.ri.gov/act-climate

[5] "Heating Sector Transformation." 2022. Official State of Rhode Island Website. State of Rhode Island Office of Energy Resources. July 27, 2022. https://energy.ri.gov/heating-cooling/heating-sector-transformation

[6] "Electrifying Transportation." 2022. Official State of Rhode Island Website. State of Rhode Island Office of Energy Resources. July 18, 2022. https://energy.ri.gov/transportation/electrifying-transportation

[7] "Power Sector Transformation." 2022. Official State of Rhode Island Website. State of Rhode Island Office of Energy Resources. July 20, 2022. https://energy.ri.gov/transportation/electrifying-transportation

[8] "2022 Update to the 2016 Greenhouse Gas Emissions Reduction Plan." 2022. Official State of Rhode Island Website. State of Rhode Island Executive Climate Change Coordinating Council. December 14, 2022. https://climatechange.ri.gov/act-climate/working-draft-workplan

[9] Throughout: "proposal" refers to the entirety of investments, actions, and tasks proposed herein. The total proposal cost is $285M, comprised of $50M federal share and $235M non-federal share (~80%).

DER onto the EPS, and (3) an annual meeting with personnel supporting smart grid deployment to understand challenges, needs, and opportunities for improvement.

Replicability: PPL Corporation's affiliate (PPL Electric) in Pennsylvania's successful grid modernization is a proof-of-concept for the integration of these advanced technologies, and the Project Team will put this modern grid to the test with RI's climate and clean energy mandates. Rhode Island's relatively high penetration of DER and its push toward strategic electrification offer the perfect climate to refine how we operate within a modern grid ecosystem. <u>To maximize impact through replicability, the Project Team will develop a case study on its grid modernization investments, insights, and lessons learned</u>.

Technical Description

Relevance and Outcomes: Proposal directly advances FOA objectives, improves grid flexibility

The EPS is changing significantly because of increasing adoption of additional renewable generation sources, including DER; beneficial electrification; EVs; electric heat pumps (EHPs); and advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business, and that transformation is expected to accelerate. <u>This decarbonization transition has fundamentally changed the nature of EPS operations</u> by prompting integration of DER and resulting in two-way power flow that is more dynamic and less predictable to manage to ensure safe and reliable electric service. The Project Team experiences these challenges in operating the EPS today. The increased complexity will grow as Rhode Island advances toward its climate and clean energy mandates.

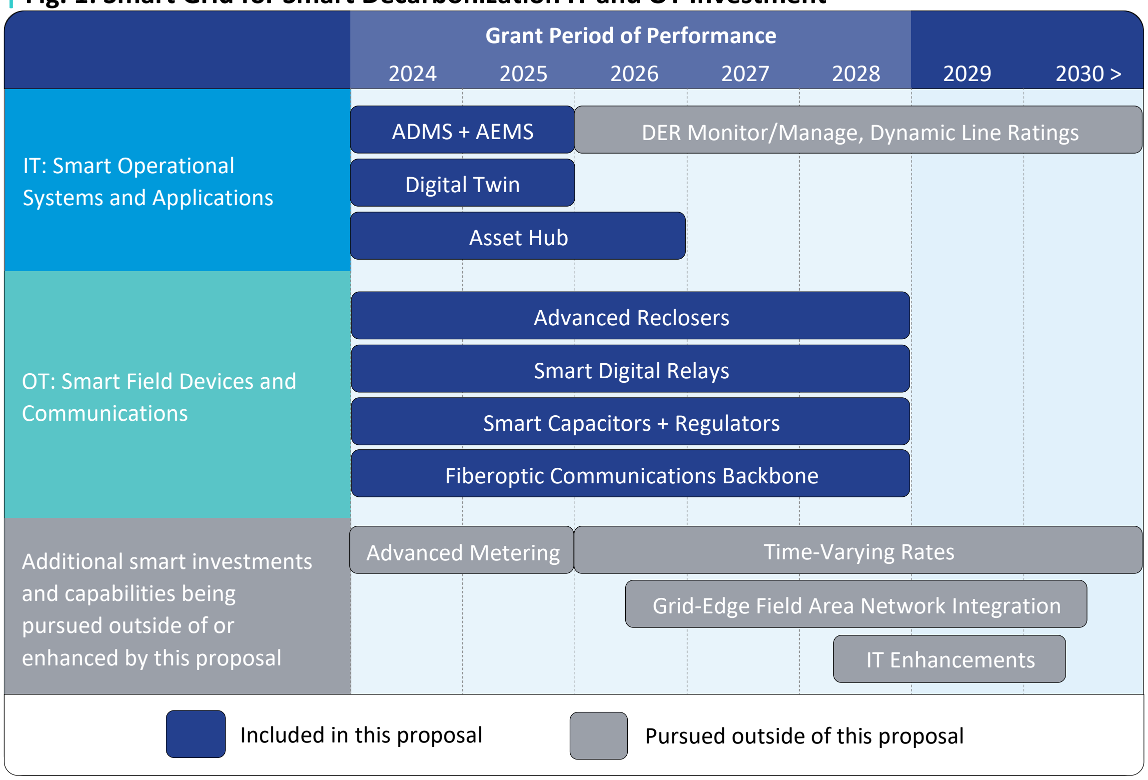
RIE must invest in <u>the necessary, real-time situational awareness of system conditions, together with the necessary control capabilities to mitigate system risks</u> and facilitate future investment that further enhance the safety and reliability of the EPS while delivering increased benefits. The proposed IT and OT investments are a holistic solution to achieve the grid flexibility required for a decarbonized future. IT solutions – ADMS and AEMS, Digital Twin, and Asset Hub – are the requisite foundation for automated data processing and grid operations. Smart devices in the field both provide the granular data and carry out the commands given by the IT systems. The fiberoptic communications backbone connects the IT and OT to ensure these communications are received. With these interrelated investments in place, the Project Team will have transformed a first-generation, fossil-fueled analog EPS to the automated, digital platform needed to interconnect decarbonized DER and serve electric end uses, transportation, and heating. This proposal will:

- increase the capacity of transmission facilities or the capability of the transmission system to reliably transfer increased amounts of electric energy;
- prevent faults that may lead to wildfires or other system disturbances;
- integrate variable renewable energy resources at the transmission and distribution levels; and,
- facilitate the aggregation and integration (edge-computing) of EVs and other grid-edge devices or electrified loads.

Supporting State Policy: This proposal and its intended outcomes directly advance RI's climate and clean energy mandates. These mandates require 100% renewable electricity by 2033 and economy-wide, statewide net-zero greenhouse gas emissions by 2050. To achieve these mandates, Rhode Island is anticipated to experience roughly a doubling of load and a three-fold increase in renewable energy; this proposal is necessary to provide the requisite grid flexibility.

The Project Team includes a letter of engagement from the Rhode Island Office of Energy Resources to further ensure alignment with state policy through continual engagement.
Feasibility: This proposal is both technically and practically feasible, backed by the demonstrated success and experience of the Project Team. One subset of the proposed investment is backed by intensive data-driven modeling and years of stakeholder engagement[10], as evidenced in RIE's Grid Modernization Plan (GMP), filed with the Rhode Island Public Utilities Commission (RIPUC) in December 2022. The GMP is a blueprint for smart grid investment in RIE's distribution system to address safety and reliability needs and to ensure that RIE is able manage the evolving electric distribution system efficiently and affordably in the future, while maintaining the flexibility to adapt to the actual pace of the energy transition through the adoption of DER and the shift to EVs, EHPs, and other forms of electrification.

Fig. 1: Smart Grid for Smart Decarbonization IT and OT Investment



The other subset of the proposed investments is backed by the success of PPL Corporation's affiliate in the digital transformation of its EPS. This playbook has been so successful – as demonstrated by measurable improvements in reliability, operational efficiency, and customer satisfaction – that PPL Corporation's other affiliates (including RIE) are adopting it. The proposed investment relevant to the transmission system are backed by this playbook, and the workplan described herein leverages lessons learned and team expertise.

[10] Stakeholder engagement was through RIE's Power Sector Transformation Advisory Group (PSTAG; 2018-2022). Stakeholders in PSTAG represent policy, regulation, low-income customers, environmental advocates, non-regulated power producers, and renewable energy developer interests, thereby ensuring comprehensive value of this portfolio and mitigating risks with its implementation.

Innovation and Impacts: The Project Team proposes an integrated suite of IT and OT smart grid investments to provide the requisite capability, visibility, and control grid operators need to manage complex two-way power flows.

| Table 1: Proposed Smart Grid IT and OT Investments

	Investment	Brief Description
IT	**Advanced Distribution + Energy Management Systems (ADMS and AEMS)**	ADMS is an enterprise software platform used by RIE to command and control the electric distribution system, including outage management and system operations. AEMS is the equivalent software platform used by PPL to command and control the electric transmission system, including outage restoration and system operations, including dynamic line ratings (DLR), smart alarms, and automated restoration.
	Digital Twin	Digital Twin is an upgraded GIS mapping software with a new Utility Network ESRI tool and Automated Utility Design (AUD) tool to supplement geographic mapping of physical assets with smart modeling of interactions (e.g., electrical, mechanical, communication) of each component on the EPS.
	Asset Hub	Asset Hub will centralize and maintain data related to infrastructure assets and analyze data (using artificial intelligence and machine learning) and recommend action to planners and operators.
OT	**Advanced Reclosers**	Advanced Reclosers are breaker equipped with a mechanism programmed to automatically close after it has been opened due to a fault, effectively sectionalizing the EPS so fewer customers are affected by any single outage.
	Smart Digital Relays	Smart Digital Relays are communication-ready relays that can adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups, aimed to reduce outages and improves restoration time.
	Smart Capacitors and Regulators	Smart Capacitors and Regulators adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies and increase grid flexibility.
	Fiberoptic Communications Backbone	The Fiberoptic Communications Backbone will support communications to and from substations to significantly improve data flow, reliability, and resiliency of communications.

Each individual IT and OT technology is described below, but these individual technology elements should not be considered individually, rather as components purposefully designed to function together to optimize benefits for the power system and customers.

> IT investments: putting the smart into 'smart grid'

ADMS and AEMS intelligently processes data for automated operations.

Current levels of DER penetration, which will increase as Rhode Island decarbonizes, result in rapid changes on the EPS and two-way power flow. Whereas grid operators could previously manage the power system manually, these complex electrical dynamics necessitate an automated approach to grid operations.

On the distribution side: ADMS is a combination of the software platforms Outage Management System (OMS), Distribution Management System (DMS), distribution supervisory control and data acquisitions (SCADA), and Distributed Energy Resources Management System (DERMS). ADMS provides the grid operator with a unified view of the distribution network and connects to smart field devices to enhance situational awareness and grid control. ADMS improves the management of outage restoration, automates processes, and provides data on critical grid functions including fault location, peak demand management, and isolation and restoration of potential problem areas. Furthermore, ADMS will integrate with SCADA software, interconnecting asset health systems and respective data repositories to build a more comprehensive digital ecosystem. The analogue to ADMS on the transmission side is AEMS, which also enhances operators' ability to command and control the transmission system, including outage restoration and system operations. The Project Team will upgrade RIE's distribution operating center to have ADMS, and PPL's transmission operating center to have an upgraded version of AEMS.[11]

Federal funding will accelerate full deployment of the ADMS suit of applications by up to two years, including the addition of applications Fault Location Isolation and Service Restoration (FLISR), Volt/Var Optimization (VVO), Conservation Voltage Reduction (CVR) and dispatch. The Project Team will expand innovation using DERMS, which allows grid operators to monitor and forecast DERs remotely and is the foundation for a program called DER Monitor/Manage (DER M/M). In DER M/M, grid operators communicate with smart inverters to make minor adjustments warranted by hyper-local grid conditions in the few hours each year they may be needed. By doing so, DER can interconnect to the grid more strategically, thereby reducing system modification costs and enabling deeper decarbonization. The Project Team will develop a case study on the stakeholder process to revise RIE's interconnection tariff to allow for DER M/M to maximize impact and replicability. Federal funding will unlock the upgrade to AEMS, including a transmission-level digital twin and dynamic line ratings (DLR). The Project Team will use existing transmission data and data incoming from transmission-level sensors as they are deployed to develop a digital geographic representation of the transmission system to support planning and decision-making based on granular transmission system needs. The upgrade will allow the Project Team to develop DLR for the transmission system. DLR has the express benefit of increasing transmission capacity, a key objective of this FOA.

The Project Team will mitigate risks associated with ADMS and AEMS by leveraging lessons learned through prior experience and through a carefully designed workplan with deliberate rollout and stakeholder engagement. RIE has experience with its VVO pilot on 10% of its distribution system. This proposal will result in full, territory wide VVO implementation and

[11] PPL's Affiliates ("Affiliate Applicants") are also submitting applications for federal funding under DE-FOA-0002740 Topic Area 2 to support ADMS, AEMS, Asset Hub, and Digital Twin, which are enterprise-wide systems. The Project Team assures there will be no duplication of federal funding: each Affiliate Applicant only includes each Affiliate's cost ration for these enterprise-wide line items. In this instance, the Project Team only includes the cost of ADMS, AEMS, Asset Hub, and Digital Twin allocated to RIE. Furthermore, each Affiliate Applicant submits its cost share proposal does not include duplicative federal funding. In this instance, the Project Team's cost share is derived from RIE-based cost recovery. In summary: there is no potentially duplicative federal funding risk; awarding more than one Affiliate Applicant will not result in duplicative federal funding.

will leverage both RIE's and PPL's experiences with VVO to mitigate risks with deployment and operation. The Project Team will draw on insights and lessons learned from PPL Electric's DER Management Pilot when revising RIE's interconnection tariff to allow for DER M/M to mitigate regulatory and industry risk. The Project Team's stakeholder engagement plan (described in more detail in Subtask 7.2 and in the Community Benefits Plan) brings industry, policy, and regulatory stakeholders to the table to inform and develop practical program design and tariff provisions for DER M/M. The Project Team will also leverage PPL's experience with transmission system DLR to ensure effective deployment and operation.

Digital Twin: The groundwork for smart modeling, planning, and decision making

Many utilities have a geographic information system (GIS) toolkit to map EPS assets and support modeling used for planning and analysis; this basic GIS was suitable for one-way power flows and predictable system loads. However, the complex electrical dynamics we see today necessitate a more realistic, granular, and dynamic mapping tool.

The Project Team will upgrade its GIS mapping software with a new Utility Network ESRI tool and Automated Utility Design (AUD) tool, collectively referred to as a Digital Twin. Digital Twin supplements geographic mapping of physical assets with smart modeling of interactions (e.g., electrical, mechanical, communication) of each component on the EPS. The new model allows planners to run virtual grid simulations to understand the implications of introducing new assets to the EPS. The Project Team will fully integrate Digital Twin with ADMS, Asset Hub (described below), and existing software like the Project Team's cloud database, integration hub, 3D mapping and design software. By assembling geospatial information on grid assets and modeling the numerous relationships and interactions between grid components, Digital Twin enhances the value of smart grid investments with smarter decision making. Smart decision-making means improved planning and integration of new assets to the existing EPS; analyzing assets, subcomponents, and relational data; and understanding potential two-way power flow.

Smarter decision making can lead to operational cost efficiencies and reductions, improved service reliability, and a superior customer experience. Digital Twin will allow for more precise and potentially proactive identification of equipment failures, quicker and more efficient routing of field repair technicians, and reduced outage durations for customers. By integrating enhanced GIS functionality with customer service interfaces, the Project Team will also improve customer experience with better outage reporting and visibility into service routes and schedules. The Project Team will leverage insights and capabilities from its previous experiences to mitigate risks associated with deployment and use. Federal funding unlocks this investment, which will not occur but-for federal funding.

Asset Hub consolidates and organizes data for efficient operations

To take care of RIE's smart grid, the Project Team will create what it's calling the Asset Hub to centralize, maintain, and analyze data related to infrastructure assets. This data includes critical historical information about each asset (e.g., maintenance history, age, manufacturer, historical performance, etc.) and real-time telemetry data (e.g., temperature, voltage, frequency, etc.) collected via current field sensors (i.e., reclosers). In addition to housing this rich data, Asset Hub will have capabilities to analyze data (using artificial intelligence and machine learning) and recommend action to planners and operators. The Project Team will build out this capability by programming algorithms based on business rules. For example, Asset Hub will be able to make assessments about a particular asset's health and flag when that asset is likely to need repairs, before the asset actually breaks, incurs damage, or causes an outage. Altogether, Asset Hub will support service reliability and operational efficiency.

Federal funding will unlock Asset Hub. The Project Team will leverage PPL's years of data-driven analysis to support the implementation and use of Asset Hub. The Project Team is committed to smart, data-driven analysis to reduce operational cost through efficiency.

> Smart OT operationalizes IT insights

Advanced reclosers improve reliability

An advanced recloser is a breaker equipped with a mechanism programmed to automatically close after it has been opened due to a fault. Advanced reclosers also effectively sectionalize the EPS such that a single segment of a feeder serves fewer customers; in other words, sectionalizing the grid means fewer customers are affected by any single outage. Advanced reclosers are necessary OT components to operationalize ADMS functionality.

Advanced reclosers provide the requisite data and operational functionality to improve service reliability. Unlike traditional reclosers, advanced reclosers can communicate with ADMS: advanced reclosers can send data to ADMS to analyze and can receive instructions from ADMS on how to operate. When used in combination with ADMS, advanced reclosers allow for load control and near real-time (typically within seconds) power measurements. The enhanced sensing and data communication from advanced reclosers is the OT requirement to operationalize ADMS's FLISR application. This combination of IT and OT reduces the number of permanent outages by automatically reclosing if a fault is detected. If multiple attempts to reclose are unsuccessful (meaning the fault persists), the advanced recloser will open and remain open, then communicate information about the fault event to ADMS's FLISR application. ADMS FLISR, advanced reclosers, and other smart devices work in tandem to automate power restoration by homing in on the location of the fault, isolating the fault, and redirecting power to as many affected customers as possible, reducing both the impact and duration of power interruptions.

The Project Team will install 1,561 advanced reclosers to improve service reliability by operationalizing OT systems and sectionalizing the power system. The Project Team determined the number and location of reclosers (which include both mail line and tie point advanced reclosers) based on three criteria: (1) customer segmentation targets, (2) long-term system configuration, and (3) DER penetration. The Project Team set an objective to sectionalize the electric grid into segments of 500-customers or less. To avoid unnecessary investment and optimize proposed locations for the advanced reclosers, the Project Team took into consideration alternative operational solutions that called for the reconfiguration or conversion of certain circuits. The Project Team further refined the proposed locations of the advanced reclosers based on DER penetration on each feeder. DERs reduce available fault current and can desensitize protection equipment; advanced reclosers can mitigate these impacts.

These additional advanced reclosers represent a quadrupling of advanced reclosers RIE has already deployed across its service area: 574 advanced reclosers on over 235 feeders; 62 midline reclosers and 107 reclosers at the point of common coupling due to customer requests for DER interconnections and 377 midline reclosers in the course of business as usual to maintain and improve safety and reliability, address damage and failure, and as part of asset replacement. Quadrupling RIE's fleet of advanced reclosers not only improves service reliability by sectionalizing the distribution system but can reduce the frequency and duration of permanent outages that customers experience via full integration with ADMS.

The proposed expansion and acceleration of advanced reclosers in conjunction with all IT and OT investment is expected to result in real reliability improvements. Table 2 summarizes these expected improvements, as estimated using detailed system modeling based on actual outages over the prior five years. This table demonstrates how if RIE had the proposed investments, outages could have been prevented or shortened. In addition to the reliability benefits, reclosers offer numerous other advantages, such as improved system visibility, system configuration flexibility, enhanced protection capability, voltage data to improve VVO, and a host of operational efficiencies.

The Project Team recognizes the risk of supply chain delays to procuring the magnitude of equipment needed for the proposed IT and OT expansion. The Project Team, however, believes that the risk of delay is likely due to the time required for manufacturers to expand production capabilities; lead times for advanced reclosers are now 34-36 weeks. As a result, the Project Team reserved a substantial number of production slots to mitigate supply chain delays. If existing manufacturers are unable to meet the entirety of the orders, the Project Team is prepared to engage in new vendor relationships to ensure successful delivery within the proposed deployment timeframe.

Table 2: Advanced reclosers improve reliability and resilience

Day Type	Blue Sky Day		Major Storm (IEEE TMED)	
Customers per recloser	500	1000	500	1000
Customers interrupted (CI)	207,191	207,191	143,120	143,120
Total CI with advanced reclosers	79,500	159,000	61,100	122,200
Delta CI	127,691	48,191	45,825	15,690
SAIFI improvement	0.258	0.097	0.092	0.032
SAIDI improvement	16.96	6.42	75.14	25.73

Notes: Data from actual circuit breaker and recloser events January 2017-December 2021; 495,622 total customers served. Blue sky day assumes: 159 events; Customer Average Interuption Duration Index (CAIDI)=66 minutes; automated switching takes <1 minute. Major storm assumes: 122 events; CAIDI=813 minutes; 75% successful operations during storms. SAIFI/SAIDI = System Average Interuption Frequency/Duration Index

Smart digital relays enhance system visibility and control amid increasingly variable generation

Rhode Island's decarbonization mandates will result in removal of the inertia-based generation that has long stabilized system frequencies and replace it with variable sources that require more intelligent monitoring devices. Relays are devices that monitor and adjust characteristics related to power quality. Intelligent and automated decision-making is becoming more important than ever for RIE to maintain operating costs, safety, and provide electric service reliability. Electromechanical relays, which are predominate in substations, are dated and provide little data or flexibility that will be needed to manage and operate in the future. Smart digital relays (microprocessor relays) can adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups. Additionally, the fault location information provided by digital relays reduces outages and reduces the time field technicians spend searching for issues. Improving how the power system is monitored and controlled can provide operations and maintenance benefits that exceed the initial capital investment. The Project Team will upgrade solid-state, first-generation electromechanical relays to new, smart, communication-ready digital relays over five years. The Project Team inventoried and categorized electromechanical relays based upon upgrade complexity and ease of replacement. 32 relay replacements will utilize the existing PPL standard for pre-wired relays within an outdoor enclosure. 87 relay replacements will be installed within the breaker itself and will require development of a new PPL standard.

There are many advantages to upgrading old electromechanical, solid-state, and first-generation electromechanical relays. Reliability improves because there is less direct wiring and interconnection wiring. Reliability and security of multifunction logic and settings are improved with next-generation user interface software. Remote input/output modules, remote analog/digital inputs, and thermal measurement capabilities have expanded protection, control, and monitoring capability. New protection and monitoring features improve power system equipment life and increase personnel safety. Maintenance costs are reduced, while internal watchdogs alert the user if the relay has a problem. Settings groups can be changed instantaneously to adapt to varying power system requirements. Digital relays offer a variety of secure communications capabilities for interfacing with Smart Grid controls, SCADA systems, and business networks. Event memory is larger for more on-board, standardized oscillographs and event reporting. Data from the upgraded relays is used in conjunction with software to predict failures before they occur, respond faster to incidents, and integrate data with business processes to make RIE more efficient and reliable which will result in customer savings, improved services, and increased customer satisfaction.

Smart Capacitors and Regulators

For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range which is +/- 5% of the nominal value. Coincident voltages along the distribution system will vary by location on the feeder, and the voltage at any delivery point will also vary with time. In the past, voltage regulation was relatively predictable. With one-way power flows, voltage tended to "drop" from the head-end of the feeder to the remote-ends of the feeder due to the resistance of the wires and the distribution of load along them. To compensate for this voltage drop, capacitors and voltage regulators have traditionally been installed to boost the voltage to stay within the required voltage range. Because electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. With current levels of DER penetration, simple autonomous settings are insufficient for RIE to maintain compliance with voltage standards.

To alleviate these issues, The Project Team will replace or upgrade 808 capacitors and 80 regulators with Smart Capacitors and Regulators that adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies. Accelerated deployment of smart capacitors and regulators with advanced controls will provide voltage and reactive power control to enable management of voltage along the distribution feeder within required ANSI voltage standards. The accelerated deployment of smart capacitors and regulators will also integrate with the ADMS application VVO, resulting in savings and operational benefits.

Fiberoptic Communications Backbone

Currently, leased cellular communications are used to communicate with automated devices in substations and with automated devices that were installed on distribution lines. Leased cellular service is limited in bandwidth and is subject to greater interference, resulting in risk of inadequacy during both mundane communication with controllable devices and in emergency situations. Cellular, especially when used as a backhaul carrying significant data traffic that is critical to operations, jeopardizes system reliability and resiliency.

The Project Team will deploy a private fiberoptic network in Rhode Island to support communications to substations where it will be used to backhaul information from substations. This investment will replace leased cellular services to improve data flow, reliability, and resiliency of communications. The backhaul fiberoptic communications backbone will consist of 142 miles of fiberoptic cable and will reduce RIE's annual operations and maintenance costs.

Replicability at Scale: This proposal will reduce perceived risk for project deployment, lead to further deployment at scale, and lead to additional private sector investments. Perceived risk will be reduced through case studies, industry communication, and real demonstration of technical feasibility, success, and impacts. Reduced risk is likely to lead to deployment of smart grid technologies in other states and utility territories preparing their EPSs for smart decarbonization. Altogether, these investments are likely to lead to additional private sector investment from clean energy and smart grid industries.

Workplan

Project Objectives: Enable smart decarbonization on schedule, on budget, and equitably

The goal of the proposed smart grid investment is to enable smart decarbonization, such that the State of Rhode Island can meet its climate and clean energy mandates safely, reliably, and affordably. In doing so, the Project Team will demonstrate to the nation a viable path to aggressive decarbonization at scale. In developing this proposal and workplan, the Project Team has the following project objectives:

1. Leverage the Project Team's collective expertise and strong stakeholder relationships to develop a practical, efficient, and just-in-time deployment plan that results in successful project deployment and meaningful community engagement.
2. Invest in "no-regrets" foundational solutions first as determined by extensive data-driven electrical analysis and decarbonization scenario modeling.
3. Defer to stakeholders with first-hand understanding to make sure plans for deployment, cost recovery, and ongoing operations work for all customers, with special focus on underrepresented customers in disadvantaged communities (DACs).[12]

[12] The Project Team adopts DOE's definition of disadvantaged communities (DACs) based on July 20, 2021, Memorandum for the Heads of Departments and Agencies from Shalanda D. Young, Brenda Mallory, and Gina McCarthy. DACs are "either a group of individuals living in geographic proximity to one another, or a geographically dispersed set of individuals (such as migrant workers or Native Americans), where either type of group experiences common conditions" where those conditions may include, but are not limited to, "low income, high and/or persistent poverty; high unemployment and underemployment; racial and ethnic residential segregation, particularly where the segregation stems from discrimination by government entities; linguistic isolation; high housing cost burden and substandard housing; distressed neighborhoods; high transportation cost burden and/or low transportation access; disproportionate environmental stressor burden and high cumulative impacts; limited water and sanitation access and affordability; disproportionate impacts from climate change; high energy cost burden and low energy access; jobs lost through the energy transition; and access to healthcare." The Project Team used the Climate and Economic Justice Screening Tool (CEJST) as its primary tool for assessing

Regarding Objective #1, the Project Team's collective expertise is described in the Qualifications section of this Technical Volume and supported by team member resumes. A description of prior robust stakeholder engagement and planned future engagement is described in the Community Engagement section of the Community Benefits Plan. The Project Team's workplan is described in depth below. This workplan is just-in-time based on extensive data-driven electrical modeling and scenario analysis as referenced in Objective #2.[13] Objective #3 references the in-depth discussions held by the Power Sector Transformation Advisory Group, described in detail in the Community Engagement section of the Community Benefits Plan. There are several significant outcomes expected as a result of these proposed investments:

- Anticipated 30% improvement in reliability
- $50,000,000 reduction in costs otherwise recovered from customers
- An anticipated increase in available load and hosting capacities for strategic electrification and distributed renewable generation

The Project Team has designed its workplan and its reporting schedule to track progress toward these outcomes via SMART goals.

Technical Scope Summary: During the 60-month period of performance, the Project Team will deploy an integrated suite of IT and OT investments: ADMS + AEMS, Digital Twin, and Asset Hub; and advanced reclosers, smart digital relays, smart capacitors and regulators, and a fiberoptic communications backbone. Together, these investments will provide the capabilities, visibility, and control grid operators need to deliver safe, reliable, affordable, decarbonized power to customers.

Strategy to comply with Buy America requirements: *The proposal will involve the construction, alteration, maintenance and/or repair of public distribution and transmission utility infrastructure within the United States. While, for the purposes of this FOA, the Project Team, which is a for-profit entity as defined in the FOA, is not required to comply with the Buy America Act or the Build America, Buy America Act requirements ("Buy America" requirements) for the FOA infrastructure projects, RIE will exercise reasonable efforts, to the extent possible, to source materials within the United States, as available and appropriate, including, but not limited to, based on lead times.*

Work Breakdown Structure (WBS) and Task Description Summary: The Project Team divides its workplan into discrete performance periods aligned with Rhode Island's annual capital investment regulatory review requirements. Rhode Island's Revenue Decoupling Act requires RIE to file an annual investment plan for "(1) capital spending on utility infrastructure; (2) operation and maintenance expenses on vegetation management; (3) operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and (4) any other costs relating to maintaining safety and reliability that are mutually agreed upon by the [Division of Public Utilities and Carriers] and [RIE]." [14] This annual

impacts of proposed projects on disadvantaged communities. Where appropriate, the Project Team supplemented its analysis using tools developed by Rhode Island state agencies.

[13] This analysis is described in detail in Section 5 of RIE's Grid Modernization Plan (the Project Team does not describe the details of this analysis here due to page length constraints, but eagerly refers reviewers to this resource for more information) https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/2256-RIE-Book2-%20GMPlan.pdf

[14] http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.1.HTM

investment plan, called the Electric Infrastructure, Safety, and Reliability Plan (ISR Plan), covers applicable spending for the fiscal year (FY) ending on March 30. Spending is reconciled on an annual basis through the same ISR Plan and regulatory oversight. Quarterly compliance reports are also required to track progress and ensure accountability.

The Project Team developed its workplan to align with this annual cadence of regulatory filings, with the regulatory decision representing the go/no-go decision point between each period of performance. The intent of this decision point is to adjust proposed spending-down of federal funding to align with actual planned work and cost share. The Project Team views this structure as particularly advantageous for two reasons. First, having certain decisions about deployment schedules and spending on an annual basis mitigates risk of unspent federal funding. Second, the public utilities commission is required by statute to render a decision within 90 days, which mitigates the risk of delays and sliding schedules.[15]

End of Project SMART Goal: The End of Project SMART Goal is 100% installation of all IT and OT components described in the Technical Description section on the Technical Volume. The expected outcomes of 100% installation are the reliability improvements, cost reductions, and increased load and hosting capacities, reporting for which is described in the subsection above. To ensure progress toward the End of Project SMART Goal, the Project Team sets Annual SMART Technical Goals related to progress toward 100% installation. Expected progress for each IT and OT component is detailed in Table 4, below.

Project Management: Throughout its workplan, the Project Team identifies the lead for each task and subtask, as well as key team members. The specific qualifications of these personnel are detailed in the Qualifications section of the Technical Volume and supported by their resumes (included in application materials). Kathy R. Castro (Principal Investigator), Director of Asset Management and Engineering for RIE and James Conrad, Director of Product Portfolio for PPL, will lead OT and IT deployment, respectively, leveraging their years of technical and team management experience. Carrie A. Gill, Ph.D., Senior Manager of Regulatory Strategy for RIE will coordinate stakeholder engagement activities leveraging the capabilities of RIE's External Affairs team. The Project Team includes a specific Task for project management, led by Castro, to demonstrate the organization with which RIE and PPL approach project management. This project management task will support all critical handoffs and interdependencies. Critical interdependencies arise when stakeholder feedback needs to flow to/from technical teams. The WBS was developed such that all critical handoffs remain within the same team, under the same lead, to ensure success. In such situations, task leads will be well prepared to communicate via a biweekly internal meeting. Furthermore, all members of the Project Team work closely together on a wide variety of workstreams, so the Project Team will build on experience and prior lessons learned to ensure successful handoffs and interdependencies.

Two notable characteristics of the Project Team's project management strategy: First, the Project Team differentiates between internal project management and check-ins with DOE; this demonstrates the inherent motivation RIE and PPL have to be successful regardless of

[15] Furthermore, the Project Team will be able to adjust the workplan to its regulatory schedule during contract negotiations for complete alignment; this flexibility allows the Project Team to hit the ground running regardless of when award selection is made; thereby mitigating inherent risk that comes with uncertainty about start date for period of performance when crafting this application.

external pressure and should signal to reviewers the commitment of the Project Team to ensuring success. Second, the Project Team plans for quarterly updates to RIE and PPL leadership at the highest levels, including RIE's President and PPL's Chief Executive Officer and Chief Operating Officer; this level of communication showcases the importance of this work to future business strategy and ensures federal funding is used responsibly and meaningfully.

The Project Team has developed its workplan, using the above objectives, to successfully achieve key outcome-based and SMART milestones with the flexibility needed to stay on budget and on schedule. Resulting tasks and subtasks are described below in relation to milestones, deliverables, and go/no-go decision points, and disaggregated by budget period.

| Table 3: Tasks, subtasks, deliverables, and milestones

Task 1: Project Management and Planning (Lead: Castro)

Subtask 1.1:	Project Management Plan (Lead: Castro) – Month 1 Develop PMP within first 30 days of the award; the PMP will include an explicit workplan for filing a proposal with the RI PUC on reduction of cost recovery due to availability of federal funding; *Deliverable*: Project Management Plan
Subtask 1.2:	NEPA Compliance (Lead: Castro) – Months 1-3 Determine applicability and provide documentation for NEPA compliance
Subtask 1.3:	Cybersecurity Plan (Lead: Randle) – Months 1-60 The CSP shall be revised and resubmitted as often as necessary, during the course of the project, to capture any major/significant changes; *Deliverable*: Cybersecurity Plan
Subtask 1.4:	Continuation Briefings (Lead: Castro) – Months 1-60 Brief DOE on roughly an annual basis to explain the plans, progress and results of the technical effort; describe performance; *Deliverable*: Pre-Continuation Briefing Documents

Task 2: Install ADMS and prepare for DER M/M (Lead: Conrad)

Subtask 2.1:	ADMS DMS, OMS, FLISR, VVO, DERMS, CVO (Lead: Conrad) – Months 1-24 Build, install, test, and deploy the Digital Twin for the electric distribution system; Build, install, test, and deploy an ADMS platform consisting of traditional DMS and OMS functionality and with advanced features to include FLISR, VVO, CVR, DERMS
Subtask 2.2:	AEMS (Lead: Conrad) – Months 1-24 Build, install, test, and deploy the Digital Twin for the electric transmission system; Build, install, test, and deploy an AEMS platform that operationalizes DLR
Subtask 2.3:	Interconnection Tariff Amendments (Lead: Gill) – Months 1-24 Revise RIE's interconnection tariff to be compatible with DER M/M; coordinate internally with Johnson, Grant, Schuster, Russell Salk, Castro, Constable; *Deliverable*: Tariff Amendments
Subtask 2.4:	Produce deliverables (Lead: Gill) – Months 22-24 Entails writing, incorporating feedback from stakeholders and SMEs; *Deliverable:* Case Study

Task 3: Build and launch Digital Twin (Lead: Conrad)

Subtask 3.1:	Initialization (Lead: Conrad) – Months 1-12 Initialization includes data includes data assessment, source data mapping, and initial data pilot; develop infrastructure architecture & prototyping
Subtask 3.2:	Finalization (Lead: Conrad) – Months 13-18 Finalization includes Mock 1 & Mock 2 data migrations; infrastructure development, and system configuration design and build; AUD configuration and modeling with system integration, system acceptance, and user acceptance testing phases
Subtask 3.3:	Produce deliverables (Lead: Gill) – Months 19-24 Case study on Digital Twin; includes at least three interviews with operators to understand what works well, what challenges remain, and lessons learned; *Deliverable:* Case Study on Digital Twin

Task 4: Build and launch Asset Hub (Lead: Conrad)

Subtask 4.1:	Data collection (Lead: Conrad) – Months 1-24 Map asset health, life-cycle, and data source; build master data and life cycle status
Subtask 4.2:	Rules engine (Lead: Conrad) – Months 13-30

	Develop, test, and refine business rules for use in Asset Hub to automate processing of data
Subtask 4.3:	Produce deliverables (Lead: Gill) – Months 30-36 Entails writing, vetting of case study; incorporating insights; at least three interviews with operators who work with Asset Hub on what works well, what the challenges are, and lessons learned; *Deliverable*: Case Study on Asset Hub

Task 5: Smart Field Devices and Communications (Lead: Castro)

Subtask 5.1:	Advanced reclosers (Lead: Castro) – Months 1-60 Deploy and validate 1,339 advanced reclosers in the field
Subtask 5.2:	Smart digital relays (Lead: Castro) – Months 1-60 Deploy and validate 171 smart digital relays in the field
Subtask 5.3:	Smart capacitors and regulators (Lead: Castro) – Months 1-60 Deploy and validate 742 smart capacitors and regulators in the field
Subtask 5.4:	Fiberoptic communications backbone (Lead: Castro) – Months 1-60 Deploy and test 100 miles of fiberoptic cable; locations of deployment strategized to match locations of smart field devices such that benefits from those devices can begin to accrue

Task 6: Integration and Cybersecurity (Lead: Randle)

Subtask 6.1:	Ongoing integration of OT and IT (Lead: Conrad) – Months 1-60 Continued verification that OT and IT are working together seamlessly and accurately
Subtask 6.2:	Cybersecurity protocols and verification (Lead: Randle) – Months 1-60 Ongoing work to assure cybersecurity best practices are in place

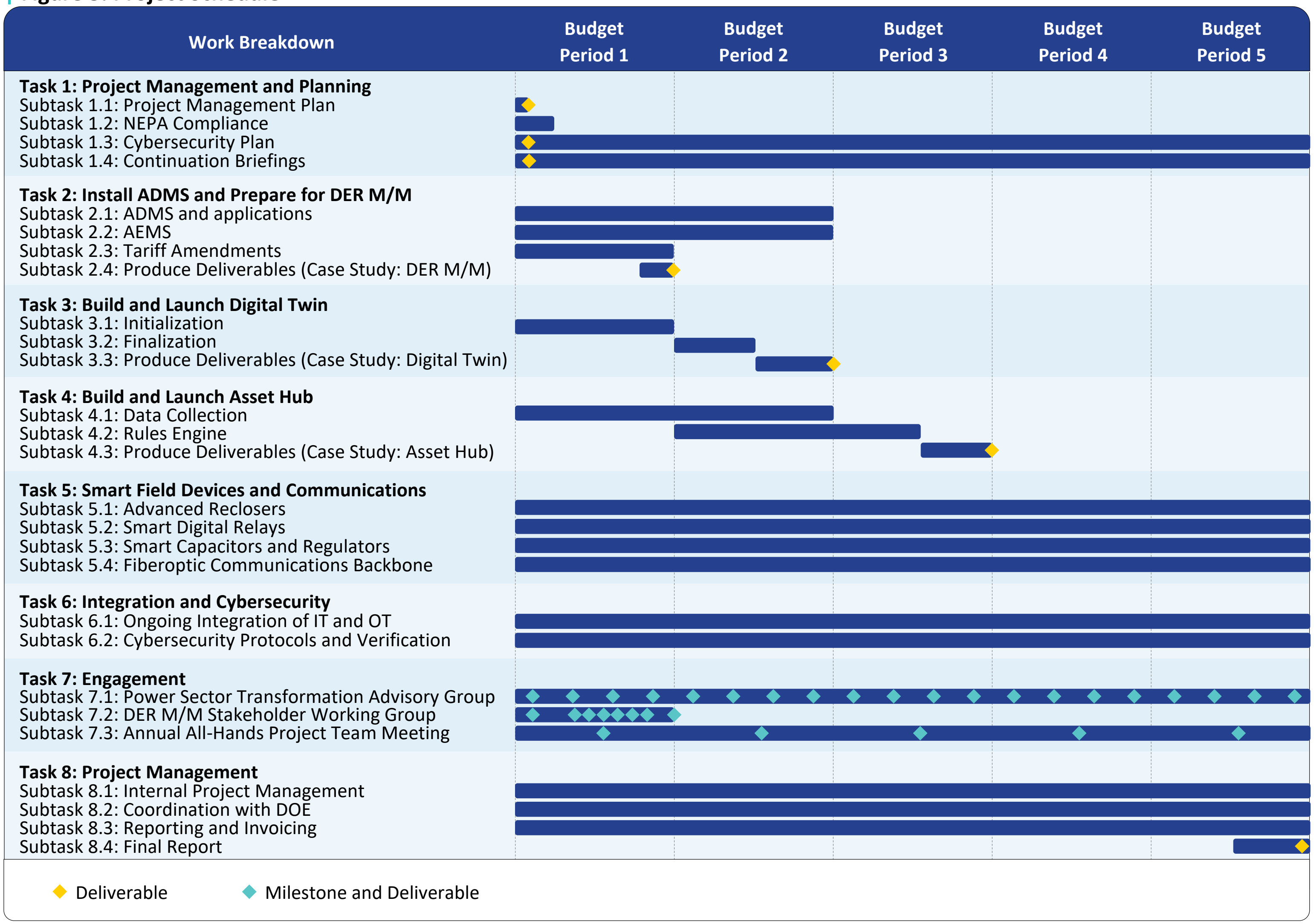
Task 7: Engagement (Lead: Gill)

Subtask 7.1:	PSTAG (Lead: Grant) – Months 3-60 Convene PSTAG on a quarterly basis through both virtual and in-person meetings; agendas will each include report out on progress, planned work, lessons learned, and insights, with time for stakeholder discussion, feedback, and questions; liaise with leads for Tasks 1-6; *Milestones*: quarterly meetings; *Deliverables*: PSTAG Meeting Materials
Subtask 7.2:	DER M/M Stakeholder Working Group (Lead: Gill) – Months 1-12 Identify members, develop agendas, coordinate at least 6 meetings, compile feedback, develop meeting materials, liaise with Castro and Conrad to translate stakeholder insights into interconnection tariff amendments; *Milestones*: stakeholders identified, 6 meetings held, tariff amendments developed; *Deliverables*: Membership List, Meeting Materials and Minutes
Subtask 7.3:	Annual All-Hands Project Team Meeting (Lead: Glenning) – Months 6, 18, 30, 42, 54 Convene annual meetings for all members of the Project Team, including personnel who install smart field devices; coordinate meeting logistics; develop agendas and meeting materials; liaise with Castro to share insights for continuous improvement; liaise with Evans to share insights related to DEIA; *Milestones*: five annual meetings; *Deliverables*: Meeting Materials and Minutes

Task 8: Project Management (Lead: Castro)

Subtask 8.1:	Internal project management (Lead: Begnal) – Months 1-60 Biweekly internal meetings with the Project Team to assess progress, identify and resolve issues, share insights, and make progress; quarterly internal meetings to report out and receive guidance from RIE and PPL leadership
Subtask 8.2:	Coordination with DOE (Lead: Begnal) – Months 1-60 Meetings with DOE grant manager, staff, and other DOE-sponsored events to share insights and progress; providing briefings; adjustments to the workplan due to annual approval cycle of Electric ISR Plan at each go/no-go decision point
Subtask 8.3:	Reporting and invoicing (Lead: Grzesiuk) – Months 1-60 Quarterly financial and performance reporting; other reporting as required
Subtask 8.4:	Final report (Lead: Gill) – Months 54-60 Develop the final report to include all case studies, additional insights, recommendations for future research and funding, best practices and lessons learned from community engagement, and steps for replicability; *Deliverable*: Final Report, including drafts for review and feedback

Figure 3: Project Schedule



Milestones Summary and Go/No-Go Decision Points: Table 4 summarizes the expected outcomes of each budget performance period, go/no-go decision points, engagement milestones, and Annual Technical SMART Milestones, along with expected deliverables. Milestones specify stakeholder, community, and labor engagement for each quarter of the 60-month performance period. As detailed in the Community and Labor Engagement section of the Community Benefits Plan, the Project Team commits to three distinct spheres of engagement, all of which will strengthen this project and its outcomes:

1. Stakeholder Engagement: The Project Team will report out to and receive feedback from its Power Sector Transformation Advisory Group on a quarterly basis.
2. Community Engagement: The Project Team will convene a DER M/M Stakeholder Group to inform interconnection tariff amendments, the design of the DER M/M program, and to support process and impact evaluation of DER M/M. These insights will also be captured in the Case Study on DER M/M so that lessons learned can be replicated.
3. Labor Engagement: The Project Team will hold an annual meeting with field personnel charged with installation of smart devices and fiberoptic cable. The intent of this annual meeting is to understand how installation and related processes might be adjusted to improve safety, efficiency, and productivity. These lessons learned will inform continuous improvement and will be captured in the Final Report on Smart Grid for Smart Decarbonization.

These three spheres of engagement are further described within Task 7, below. The intent of calling out engagement as its own task is not to signal that the engagement will be isolated from the technical deployment of IT and OT investments, rather to highlight the emphasis the Project Team places on ensuring this engagement is done properly. Leads for engagement will work hand-in-hand with leads for deployment tasks (Tasks 2-6) throughout the period of performance to ensure full integration of engagement with deployment.

Table 4: SMART milestones and go/no-go decision points

Event	Timing	Description/Expected Outcome
BP1	Months 1-12	• ADMS OMS, DMS, FLISR, VVO 75% installed • AEMS 75% installed • Digital Twin initial release • Asset Hub initial data collection 50% complete • Installation of smart field devices and fiberoptic communications backbone 22% complete • Interconnection tariff amendments developed
M1.1	Month 3	*Deliverable*: Project Management Plan • DER M/M Stakeholder Group identified for interconnection tariff amendment (at least 10 stakeholders) *Deliverable*: DER M/M Stakeholder Group Membership List • PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M1.2	Month 6	• At least 3 DERM M/M Stakeholder Group meetings *Deliverable*: Meeting Materials and Minutes ○ PSTAG Meeting *Deliverable*: PSTAG Meeting Materials • Annual All-Hands Project Team Meeting *Deliverable*: Meeting Materials and Minutes
M1.3	Month 9	○ At least 3 DERM M/M Stakeholder Group meetings *Deliverable*: Meeting Materials and Minutes • PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M1.4	Month 12	• Interconnection tariff amendments developed • PSTAG Meeting *Deliverable*: PSTAG Meeting Materials

Event	Timing	Description/Expected Outcome
Annual SMART Milestones		• *Annual SMART Technical Milestone*: % installed relative to project goal by IT and OT component (as specified in the BP1 expected outcomes row, above) • *Annual SMART DEIA Milestone*: participation in Annual All-Hands Project Team Meeting; year-on-year improvement in diversity of participants
Go/No-Go	Month 12	• Regulatory approval of FY 2025 Electric ISR Plan
BP2	Months 12-24	• ADMS OMS, DMS, FLISR, VVO 100% installed • ADMS CVO 100% installed • ADMS DERMS 50% installed • AEMS 100% installed • Digital Twin final release • Asset Hub initial data collection 100% complete • Asset Hub rules engine 50% initialized • Installation of smart field devices and fiberoptic communications backbone 46% complete • Interconnection tariff amendments approved
M2.1	Month 15	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M2.2	Month 18	○ PSTAG Meeting *Deliverable*: PSTAG Meeting Materials • Annual All-Hands Project Team Meeting *Deliverable*: Meeting Materials and Minutes
M2.3	Month 21	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M2.4	Month 24	*Deliverable*: Case Study on Digital Twin • PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
Annual SMART Milestones		• *Annual SMART Technical Milestone* criteria: % installed relative to project goal by IT and OT component (as specified in the BP2 expected outcomes row, above) • *Annual SMART DEIA Milestone*: participation in Annual All-Hands Project Team Meeting; year-on-year improvement in diversity of participants
Go/No-Go	Month 24	• Regulatory approval of FY 2026 Electric ISR Plan
BP3	Months 25-36	• ADMS DERMS 100% installed • DER M/M initialized • Asset Hub rules engine 100% initialized • Installation of smart field devices and fiberoptic communications backbone 69% complete
M3.1	Month 27	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M3.2	Month 30	○ PSTAG Meeting *Deliverable*: PSTAG Meeting Materials • Annual All-Hands Project Team Meeting *Deliverable*: Meeting Materials and Minutes
M3.3	Month 33	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M3.4	Month 36	• *Deliverable*: Case Study on Asset Hub • PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
Annual SMART Milestones		• *Annual SMART Technical Milestone*: % installed relative to project goal by IT and OT component (as specified in the BP3 expected outcomes row, above) • *Annual SMART DEIA Milestone*: participation in Annual All-Hands Project Team Meeting; year-on-year improvement in diversity of participants v
Go/No-Go	Month 36	• Regulatory approval of FY 2027 Electric ISR Plan
BP4	Months 37-48	• DER M/M up and running • Installation of smart field devices and fiberoptic communications backbone 91% complete
M4.1	Month 39	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials

Event	Timing	Description/Expected Outcome
M4.2	Month 42	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials • Annual All-Hands Project Team Meeting *Deliverable*: Meeting Materials and Minutes
M4.3	Month 45	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M4.4	Month 48	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
Annual SMART Milestones		• *Annual SMART Technical Milestone*: % installed relative to project goal by IT and OT component (as specified in the BP4 expected outcomes row, above) • *Annual SMART DEIA Milestone*: participation in Annual All-Hands Project Team Meeting; year-on-year improvement in diversity of participants
Go/No-Go	Month 48	• Regulatory approval of FY 2028 Electric ISR Plan
BP5	Months 49-60	• Installation of smart field devices and fiberoptic communications backbone 100% complete • All deliverables complete
M5.1	Month 51	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M5.2	Month 54	*Deliverable*: Case study write up on DER M/M ○ PSTAG Meeting *Deliverable*: PSTAG Meeting Materials • Annual All-Hands Project Team Meeting *Deliverable*: Meeting Materials and Minutes
M5.3	Month 57	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
M5.4	Month 60	• PSTAG Meeting *Deliverable*: PSTAG Meeting Materials
Annual SMART Milestones		• *Annual SMART Technical Milestone*: % installed relative to project goal by IT and OT component (as specified in the BP4 expected outcomes row, above) • *Annual SMART DEIA Milestone*: participation in Annual All-Hands Project Team Meeting; year-on-year improvement in diversity of participants

Notes: BP = Budget Period; MX.Y = Milestone corresponding to BPX, quarter Y; Go/No-Go = Go/No-Go Decision Point. RIPUC = Rhode Island Public Utilities Commission. The Electric ISR Plan is RIE's annual capital investment plan covering April 1 through March 30; each plan is denoted with an FY (fiscal year) where that year corresponds to the fourth quarter of the plan. For example, FY 2024 Electric ISR Plan corresponds to planned investments April 1, 2023 through March 30, 2024.

Any project changes will be handled swiftly and appropriately. Changes that arise due to annual approval cycles for RIE's Electric ISR Plan will be incorporated into the workplan via Subtask 8.2 in complete coordination with DOE staff. Changes that arise due to unforeseen events will be discussed and vetted both internally (Subtask 8.1) and with DOE staff (Subtask 8.2) as soon as those unforeseen events are known.[16]

The Project Team does not foresee any risks other than those described within this application. Risk mitigation strategies specific to reach risk are described throughout this application. The Project Team also views its stakeholder engagement plan as a risk mitigation strategy: transparency, accountability, and stakeholder insights will ensure work is completed efficiently and effectively throughout the period of performance. The Project Team's overall risk management strategy is illustrated in Figure x, demonstrating risk management through the entire lifecycle of the project: preemptive mitigation, advanced notice via monitoring and reporting, close and constant communication, transparency, flexibility, and feedback loops.

[16] Please note that no unforeseen events are predicted at this time; all known risks have been described in this application packet (specifically concentrated within the Technical Description section of the Technical Volume) to the best of the Project Team's ability.

Technical Resources and Qualifications

Team Qualifications: The Project Team bring holistic experience and expertise

The Project Team is highly qualified, with decades of combined experience and demonstrated success in grid modernization, complex investment, and utility management. Prime applicant RIE serves nearly 97% of the state's customers (nearly 500,000 customers). In 2016, Rhode Island was the first state in the country to deploy offshore wind. In 2019, RIE contracted for an additional 400 MW of offshore wind and is currently procuring up to another 1,000 MW. In total, this generation is expected to supply 70% of RI's electricity needs in 2030 (including the new demand required for electrification). Currently, RIE's electric grid has 504 MW of interconnected DG and ~650MW more in queue.

RIE also has a history of robust stakeholder engagement, described in further detail in the Community Benefits Plan. This history includes five years of engagement with the Power Sector Transformation Advisory Group (PSTAG). Resulting from a commission order, the PSTAG was developed via collaboration between RIE, Rhode Island Office of Energy Resources (RI OER), and Rhode Island Division of Public Utilities (RI DPUC), with members representing environmental interests, clean energy industry or businesses, community groups, customers in disadvantaged communities, and non-regulated power producers. The PSTAG convened 19 times over the five years from 2018-2022 (Figure 4) and ultimately informed RIE's Grid Modernization Plan (filed for regulatory review in December 2022).

Fig. 4: PSTAG Meetings 2018-2022

November 27, 2018	December 13, 2018	January 31, 2019	February 14, 2019	February 27, 2019
March 28, 2019	April 18, 2019	April 25, 2019	July 22, 2019	November 1, 2019
December 17, 2019	March 31, 2020	September 15, 2020	July 14, 2022	August 16, 2022
October 7, 2022	November 9, 2022	December 13, 2022	2018 2018 2020 2022	
PST Workshops with RI PUC – April 9, 2019, November 5, 2019, September 24, 2020, September 1, 2022, October 18, 2022				

Notes: PSTAG Meeting agendas included discussions regarding grid modernization, advanced metering, electric transportation, and energy storage.

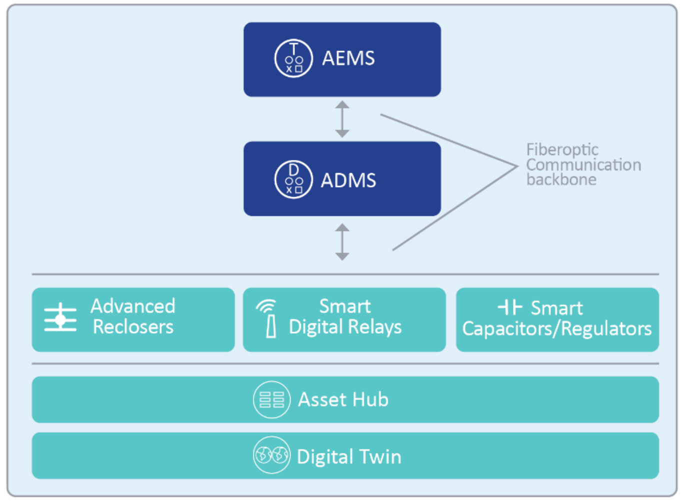
Through its experience in supporting its affiliates, team member PPL brings industry-leading experience and capabilities in deploying innovative edge of grid modernization technologies. Team member PPL's affiliate utility companies serve more than 3.2 million customers and are widely regarded as leaders in customer satisfaction and innovative grid solutions. PPL's affiliate in Pennsylvania (PPL Electric) deployed a DERMS.[17] Results from the pilot show a substantially strong benefit-cost ratio, leading to shorter interconnection times,

[17] *Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan* (DER Management Pilot); see also "Getting Ready for a Renewable Energy Future." 2020. PPL Corporation. July 14, 2020. https://www.pplweb.com/blog/getting-ready-for-a-renewable-energy-future/#:~:text=PPL%20Electric%E2%80%99s%20Distributed%20Energy%20Resource%20Management%20System%20is

lower interconnection costs, and better power quality. PPL Electric won the 2022 Smart Grid Award for its use of advanced sensors and switches to improve grid reliability in Pennsylvania.[18]

PPL's and RIE's existing equipment and facilities are sufficient to facilitate successful completion of this project; no new equipment or facilities are needed nor proposed as part of this project.[19]

Fig. 4: Visual Summary of Proposed Investment



Key Team Members: Within the Project Team, the following individuals will bring their deep and multidisciplinary knowledge to deliver these proposed investments and intended outcomes. Below, the Project Team describes the roles, time commitments, and relevant expertise and experience of these team members in relation to the proposed work at hand. Resumes for the following key team members are included in the application package.

Kathy Castro (PI) – Director of Distribution Planning and Asset Management, RIE

Castro is the principal investigator on this proposal and serves as both the technical point of contact and the lead project manager. Castro will specifically lead the deployment of OT solutions (Task 5) and Project Management (Tasks 1 and 8). Castro brings nearly two decades of utility industry experience in analysis and design, project management, corporate management, marketing, and business development. As the lead technical expert for RIE's Grid Modernization Plan, her involvement will ensure the work proposed in this project is in lockstep with investments needed to deliver safe, reliable, affordable, decarbonized electricity to customers. Furthermore, Castro's role with overseeing all distribution investment will ensure full integration with the investments proposed herein and all other investments occurring as normal course of business; thereby ensuring efficient work schedules, adequate and capable workforce, and synergistic activities in the field. Castro will allocate 10% of her time to this work over the 60-month period of performance.

Jim Conrad – Director of Product Portfolio, PPL

Conrad is the lead technical manager for all IT solutions (Tasks 2-4) and for integration of IT and OT (Subtask 6.1). Over the past decade, Conrad has been a recognized leader in innovative utility information technology. In addition to his current role leading PPL's IT Product Team, Conrad has held leadership roles in field engineering and operations at PPL Electric. His electric distribution experience includes work on many new technologies, including automated

[18] Larson, Aaron. 2022. "Advanced Power Grid Sensors and Switches Reduce Downtime and Improve System Reliability." POWER Magazine. July 1, 2022. https://www.powermag.com/advanced-power-grid-sensors-and-switches-reduce-downtime-and-improve-system-reliability/

[19] The Project Team is not requesting technical services from DOE/NNSA FFRDCs.

fault isolation, downed conductor detection, and DER Management. Conrad has the technical experience and background to ensure the successful implementation of the proposed investments, demonstrated through his work on the Keystone Solar Futures Grant and through his patent for a megavang design from his time in the Distribution Standards department. Conrad will allocate 10% of his time to this work over the 60-month period of performance.

Chris Randle – Vice President of Cybersecurity, PPL

Randle will lead integration and cybersecurity (Task 6) by supporting integration (Subtask 6.1) and leading cybersecurity protocols (Subtask 6.2). Randle's vast experience demonstrates his impressive qualifications for this role. He has more than 20 years of experience in cybersecurity, creating and executing strategies that protect Fortune 500 companies from advanced cyber threat activity. In his current role, he is responsible for the cyber safety of all PPL operating companies, including RIE. He focuses on creating and managing the strategic success of cybersecurity in the organization including the following areas: Identity and Access Management, Privileged Access Management, Cloud Security, Risk Management, Incident Response, Cyber Monitoring, ICS/OT Security, Cyber Awareness and Training, Cyber Engineering, Product Security, Vulnerability Management, CIP Compliance and SOX Compliance. He will allocate 200 hours to this work.

Brian Grzesiuk – Senior Financial Manager, RIE

Grzesiuk is the lead financial manager and business point of contact for this proposal. In leading Subtask 8.3, Grzesiuk will leverage his existing work with tracking performance and spending for capital investments to ensure quality and timely reporting. Grzesiuk's five-year tenure with RIE has led to his fluency in both financial and performance reporting. Grzesiuk leads a team of two, responsible for budgeting and forecasting for operating and capital expenditures, long-term business planning, and supporting the strategic, operational, and financial decision making for the Electric Business. Brian has a successful track record overseeing budgets and capital plans, which will further support the team in meeting milestones on time and on budget. By leveraging these synergies, Grzesiuk is able to efficiently allocate 380 hours to this project over the 60-month period of performance.

Carrie Gill, PhD – Senior Manager of Electric Regulatory Strategy for External Affairs, RIE

Gill will lead engagement generally (Task 7) and specifically coordination of the DER M/M Stakeholder Group (Subtask 7.2) and development of interconnection tariff amendments (Subtask 1.3). By leading both subtasks related to DER M/M, Gill will be able to ensure stakeholder feedback is considered and work directly with technical team members to marry stakeholder feedback with technical needs. In her role within External Affairs, Gill conducts ongoing stakeholder engagement, including as RIE's liaison with the Rhode Island Distributed Generation Board, constituents of which are prime candidates for the DER M/M Stakeholder Group (Subtask 7.2). Gill will also lead the development of all project deliverables (Subtasks 2.4, 3.3, 4.3, and 8.4), in addition to providing general support for project management. Gill's extensive experience with project management of federal grants, state and federal policy expertise, and industry experience will ensure deliverables meet the dual needs of supporting internal learnings and maximizing external impact through replicability. She will allocate 700 hours for this work.

Ryan Constable – Manager of Distribution Planning, RIE

Constable will provide critical support for OT deployment (Task 5), IT/OT integration

(Subtask 6.1), and engagement (Task 7). Constable has nearly two decades of utility planning experience and is a recognized expert in the field. Constable not only leads a team of planners, but also supports RIE's grid modernization planning efforts, including intensive modeling to understand RIE's needs as the state decarbonizes. Constable was instrumental as a partner on Rhode Island's Solar Energy Innovation Network Team (DOE funding competitive cooperative agreement, 2020-2022, Project Team led by Rhode Island Office of Energy Resources). His experience demonstrates both the depth of his expertise and breadth of his knowledge base. He will allocate 10% of his time to this work.

Dan Glenning – Director of Project Management, RIE

Glenning will lead the annual worker meeting described in Subtask 7.3, with the support from the External Affairs team, Human Resources department, and staff focused on labor and worker relations. Glenning will allocate 60 hours to these meetings, in addition to 200 hours supporting workforce hiring and project management for OT (Task 5).

Nicole Begnal – Manager of Electric ISR Plan, RIE

Begnal will lead internal project management (Subtask 8.1) and coordination with DOE (Subtask 8.2) and will support Grzesiuk with reporting (Subtask 8.3). Begnal's position already requires her to collaborate closely with Grzesiuk to not only track performance and spending of projects included in the Electric ISR Plan, but also to work with planners (Castro and Constable) and project managers (Glenning) to develop and defend practical capital investment plans. Leveraging her existing approach to collaboration, Begnal will allocate 570 hours to this work over the 60-month period of performance.

Kate Grant – Senior Manager of Regulatory Affairs, RIE

Grant will lead coordination of the Power Sector Transformation Advisory Group (Subtask 7.1), provide particular support for interconnection tariff amendments (Subtask 2.3) and provide general support for project management, particularly with ongoing updates to regulatory staff. This will build on her extensive experience overseeing Power Sector Transformation Advisory Group engagement since its formation in 2018 and serving as RIE's key liaison to regulatory stakeholders. Her priority areas of focus in recent years have included advanced metering, grid modernization, customer assistance, and demand side initiatives through a Governor appointed and senate confirmed role on the Rhode Island Energy Efficiency and Resource Management Council. Grant will allocate 200 hours to this project.

Erica Russell Salk – Manager of Customer Energy Integration, RIE

Russell Salk will support all facets of DER M/M Stakeholder Group (Subtask 7.2) and development of interconnection tariff amendments (Subtask 2.3). As the manager of the Customer Energy Integration team, Russell Salk and her team have developed deep relationships with renewable energy developers and installers. Not only will she bring these insights into consideration when engaging with the DER M/M Stakeholder Group, but she will bring back insights from the DER M/M Stakeholder Group to her team to amplify process improvements and provide additional value to the interconnection process. Furthermore, Russell Salk's deep working knowledge of the interconnection tariff will help the Project Team streamline its focus in developing amendments, resulting in efficient and productive discussions. Russell Salk will allocate 162 hours to this work.

Beth Johnson – Director of Regulatory Affairs, PPL

Johnson will provide regulatory expertise in support of interconnection tariff amendments (Subtask 2.3), as well as general support to ensure federal funding is accounted for in ratemaking to offset cost recovery from low-income customers. Johnson not only oversees a team of regulatory analysts, she has direct leadership experience in successfully implementing PPL Electric's DERMS through its *Petition of PPL Electric Utilities Corporation for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan* (DER Management Pilot).[20] Johnson's first-hand knowledge and expertise will transfer institutional knowledge and lessons learned to ensure success in Rhode Island. Johnson will allocate 200 hours to this project.

Angie Evans – Vice President and Chief DEI Officer, PPL

Evans will provide support for and oversight of all work related to the Community Benefits Plan, including but not limited to progressing DEIA actions and reporting on annual SMART DEIA milestones. In Evans' role as VP and Chief DEI Officer, she is responsible for advancing PPL's enterprise-wide diversity, equity and inclusion strategy and commitments. Evans will focus her efforts on joining quarterly leadership meetings and planning for and participation in each Annual All-Hands Project Team Meeting (Subtask 7.3). She will allocate 100 hours to this project.

David Bonenberger – President, RIE

Bonenberger will serve as the lead decision-maker and provide general support, leadership, and guidance to this project. Bonenberger's prior roles bridge the PPL and RIE teams: Prior to RIE, Bonenberger held the roles of VP of Operations Integration at PPL, through which he led the integration of RIE and PPL. In his tenure as VP of Distribution Operations for PPL, Bonenberger led the deployment of PPL's Smart Grid system (funded in part through an ARRA grant), which resulted in the biggest reliability improvement in company history. He also held the role of VP of Transmission and Substations through which he supported the PPL's grid modernization efforts. Bonenberger's utility experience spans nearly four decades. Bonenberger serves as Chair Emeritus of the Edison Electric Institute's National Response Executive Committee. He will allocate 50 hours to this project.

Al LaBarre – Vice President of Electric Operations, RIE

LaBarre will provide support, leadership, and guidance to this project, leveraging his nearly 30 years of experience in the electric industry. He will allocate 50 hours to this project.

Brian Schuster – Senior Director of External Affairs, RIE

Schuster will provide general support, leadership, and guidance to this project, especially regarding stakeholder, community, and labor engagement. Schuster leads the management of public relations and communications between RIE and the state's legislative, regulatory, and community stakeholders. His experience includes previous positions within external affairs, management, and engineering. He is also certified in Lean Six Sigma and Design Thinking, and a graduate of Leadership Rhode Island. These experiences lend themselves to both guidance and general team building, ensuring success and professional development for all members of the Project Team. He will allocate 100 hours to this project.

[20] "Getting Ready for a Renewable Energy Future." 2020. PPL Corporation. July 14, 2020. https://www.pplweb.com/blog/getting-ready-for-a-renewable-energy-future/#:~:text=PPL%20Electric%E2%80%99s%20Distributed%20Energy%20Resource%20Management%20System%20is

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PUC 9-12
Spare Transformers

Request:

Regarding the proposal to begin procuring spare transformers:

a. Do these transformers increase system reliability and resiliency compared to a system without these spares?
b. Is the procurement of these spares eligible for any federal support for programs related to reliability improvements?

Response:

a. Spare transformers can have a direct impact on system reliability and resiliency in comparison to a system without spares. When a substation transformer fails, load typically needs to be transferred to an adjacent substation and/or a mobile/portable substation needs to be transported to the failure site to supply any remaining customers and allow for the system to be restored to pre-contingency conditions. This should all happen within a matter of 24-72 hours post contingency. However, the system is not designed to be in an abnormal configuration for an extended duration. Abnormal configurations expose the electrical system to greater reliability risks because feeders are physically longer, which subjects a greater number of customers to outages caused by tree contact, motor vehicle accidents, animal contacts and equipment failure.

   Substation power transformers are all specialty items built to unique specifications that differ between each utility. There are no "off the shelf" options for substation power transformers. The lead times for these units currently range between 2-3 years from the time an order is placed. As the transition to electric transportation and heating continues to accelerate, the Company currently does not anticipate that lead times will return to less than a year in the near term. Without a sufficient inventory of spares, a utility may be forced to shift load to adjacent feeders and substations for an extended period. These substations are typically further away from the load centers, which increases line losses, causing lower voltage at the delivery point. The increased feeder length also exposes an increased number of customers to greater risk of outages from motor vehicle accidents, animal contacts, and equipment failure. With a spare transformer readily available, the failed transformer can be replaced over the course of a few days for smaller units to a few weeks for larger units, resulting in the system being restored to pre-contingency conditions far faster than waiting years for a new transformer.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

PUC 9-12, page 2
Spare Transformers

In addition to impacting system reliability by enabling the utility to return the system to pre-contingency conditions much faster than if the utility had to order a new transformer upon a failure, spare transformers can also improve system resiliency. Catastrophic weather events such as severe flooding, tornadoes, and wildfires, along with targeted sabotage and attacks, can severely impact the reliability and serviceability of the electric system. Spare transformers allow the Company to quickly recover from these events and return the system to normal.

b. The Company is not aware of any federal programs that would provide support for the procurement of the spares substation transformers the Company proposes in the FY 2025 ISR plan. Although there is a Department of Energy incentive for Energy Efficient Transformer Rebates, that program is available only for smaller distribution (point of use) transformers – not for substation class transformers, based on the size, type, and rating definitions in the federal regulations governing the program. *See* 10 C.F.R. 431.192(2), (4), and (5).

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

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PUC 9-13
Spare Transformers

Request:

On Bates page 148 of the Plan (Book 1) the text states, "The 0.9950 system reliability benchmark indicates that the company will have a spare available 99.5% of the time." In response to Division 2-17 Corrected (Book 3 Bates page 49) the response indicates "The reference reliability criteria of 0.9950 does not refer to a system reliability benchmark but to the probability that a spare transformer will be available in the event of a failure." Also,

a. Please confirm that 0.9950 is the reliability benchmark and was used as the minimum reliability benchmark to conduct a determination of optimal transformer spares based on the minimum reliability criterion as presented by *Chowdury and Koval*, 2009 (See Division 2-12).

b. Please confirm if it is RIE's understanding that an explicit interpretation of meeting the criterion is: assuming a 0.5% per year failure rate, there is a 99.5% chance the number of spare transformers is equal to or greater than the number of transformer failures within a three-year period.

c. Does the reference text present any other methods for determining an optimal number of spare transformers?

    i. If so, do the authors recommend one method over the others presented?
    ii. If the answer to part a is "yes," did RIE employ the recommended method to develop the spare transformer plan presented in the Plan?
    iii. If the answer to part b is "no," why not?

Response:

a. Rhode Island Energy confirms that 0.9950 was the minimum reliability that was used to determine the optimal number of spares based on the minimum reliability criterion as presented by *Chowdury and Koval*, 2009.

b. Rhode Island Energy confirms its understanding that an explicit interpretation of meeting the criterion is, assuming a 0.5% per year failure rate, there is a 99.5% chance the number of spare transformers is equal to or greater than the number of transformer failures within a three-year period, but the Company offers as a more concise description: Assuming a 0.5% failure rate and a 3-year transformer replacement time, there is a 99.5% chance that a replacement transformer will be available in the event of a failure.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

PUC 9-13, page 2
Spare Transformers

c. The authors offered three methods:

Minimum Reliability Criterion Model – This model uses variables such as the annual failure rate, equipment lead times, and number of in-service transformers to calculate probabilities that a spare transformer is available in the event of a failure.

Mean Time between Failures Criterion Model – This model considers the total number of in-service transformers, the transformer population failure rate, the lead time to replace a failed transformer, and the useful life of a transformer. This model attempts to calculate how many spares will be needed to ensure the mean time between failures (when all spares are depleted) is greater than the average useful life of a transformer.

Statistical Economics Criterion Model – This model considers economic impacts caused by transformer failures such as the increase in kilowatt-hour losses, revenue lost cost, customer outage cost, and includes the carrying charges for a spare transformer. Then, by using a formula to calculate the average number of units unavailable over a given amount of time (assuming all spares are used), one can calculate the preferred amount of spares based on the total cost per year.

i. The authors recommended the Statistical Economics Criterion Model.

ii. No, Rhode Island Energy did not employ the recommended method to develop the spare transformer plan presented in the FY 2025 ISR Plan.

iii. Rhode Island Energy did not select the Statistical Economics Criterion Model recommended by the authors because it assigns a cost to customer outages and inherently allows for customers to be without power if the total cost is the lowest. Rhode Island Energy will not allow extended customer outages and believes there is no economic justification for permitting long term unserved load.

PUC 9-14
Spare Transformers

Request:

Regarding RIE's response to Division 2-12, the response states the reference for the statement that 0.9950 "has been cited by IEEE to be a common benchmark amongst a wide number of utilities," is a reference to a 2009 text by Chowdury and Koval.

a. Please confirm the referenced language on page 446 of the text states the following, "If the system is to have a minimum reliability of 0.9950, a number typically used in the electric utility industry, what is the minimum number of spares that must be carried as immediate replacements?"

b. Please confirm the authors provide no reference or data to support this claim.

Response:

a. The Company confirms that, on page 446 of chapter 20, of the Power Distribution System Reliability by Ali A. Chowdhury and Don O. Koval, it states: "If the system is to have a minimum reliability of 0.9950, a number typically used in the electric utility industry, what is the minimum number of spares that must be carried as immediate replacements?"

b. The authors cite multiple references, but the specific reliability criteria of 0.9950 was not specifically cited. Rhode Island Energy has not been able to contact the author, nor has it been able to identify the specific reliability criteria in the authors' references.

PUC 9-15
Spare Transformers

Request:

In response to Division 2-16, RIE explains the resources used to determine an equipment failure rate for all transformer types of 0.5% per year.

a. Please provide the data supporting the referenced historical failure rates and any analysis on this data.
b. Please provide the results from the Doble Engineering working group survey or confirm if this is a reference to the information presented in *Hernandez et al.*, 2022 referenced in RIE's response to Division 2-13. If the latter, please explain which data was used (e.g., the average data as presented in Figure 2 of the publication, the high voltage categorized data as presented in Figure 5 of the publication, etc.)
c. Please provide the methodology and analysis that combined the information referenced in parts a and b that resulted in a 0.5% per year failure rate for all transformer types.

Response:

a. The Company had used the 0.5% failure rate while under National Grid USA ("National Grid") ownership based on a review of transformer failures. The Company has submitted a formal data request to National Grid for a summary of the supporting data, but has not yet received a response. The Company's affiliates in Kentucky – Louisville Gas & Electric and Kentucky Utilities (LG&E and KU) – performed an analysis that identified 38 substation power transformer failures in a fleet of 816 from January 2014 to January 2024, for a failure rate of 0.47%.

b. The Company's mention of a Doble Engineering working group used in the response to Division 2-16 is a reference to the information presented in the document identified in Division 2-13 reference #2. Within the referenced document, Figure 5 was used to determine a failure rate. An average was taken for all six years for transformer voltage levels from 15 kV to 115 kV, which resulted in an average failure rate of 0.51%.

c. The value of 0.5% used by National Grid, 0.47% from LG&E and KU, and 0.51% from the Analysis of Power Transformer Failure Rates, were averaged to 0.49%, rounded to 0.5%.

Prepared by or under the supervision of: Eric Wiesner and Ryan Constable

PUC 9-16
Mobile Substations

Request:

Regarding the proposal for mobile substations:

a. Do these substations increase system reliability and resiliency compared to a system without these mobile substations?

b. Do these substations increase system flexibility to allow for efficiency in system modifications compared to a system without these mobile substations?

c. Do these substations increase RIE's ability to respond to and address system changes driven by distributed energy resources compared to a system without these mobile substations?

d. Is the procurement of these mobile substations eligible for any federal support for programs related to reliability improvements?

Response:

a. Mobile substations do increase system reliability and resiliency for a system that is not designed for full redundancy as is the case in Rhode Island. Distribution systems can be planned by using various methodologies. The two more common methodologies are explained in greater detail below.

   Method 1: Design all substations such that every station has two transformers and two buses with the capability of transferring the entire load from bus to bus and transformer to transformer automatically. With this design, it is important to balance the loads and keep them at no more than 50% of the Long-Term Emergency rating of the installed transformers so that automatic transfer can be always ensured.

   Method 2: Design and load substations of any configuration up to 100% of the normal rating of the transformer. Upon a transformer or bus failure, the remaining transformers shall not be loaded above 200% of the nameplate rating, and the system must be designed such that the loading is decreased to the Long-Term Emergency rating within 15 minutes. The load on the remaining transformers must then be reduced to within their normal nameplate rating within 24 hours. This is accomplished by designing substations to allow for rapid mobile deployment to assist with reducing the loading on the remaining transformers.

Mobile Substations

Rhode Island Substations primarily have been planned using Method 2 and are loaded such that there is emergency capacity in adjacent transformers (both in the same station or in nearby stations) to carry additional load temporarily in the event of a single transformer or substation failure. There is no built-in capacity to carry that load for extended periods of time or through the peak hours of the year. Sites are designed such that a mobile substation can be installed quickly and easily to resupply most or all of the load that the failed transformer was carrying.

For additional information on how a mobile substation increases system reliability and resiliency, please see Attachment PUC 9-16, Section 2.2.1. This section outlines the various applications for mobile substations and how this equipment can be applied to respond to forced outages, weather events, and sabotage.

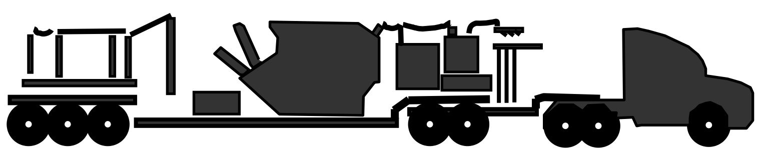
b. Yes. When replacing or repairing certain elements in the system, load needs to be transferred to adjacent transformers and feeders. This results in the system being placed in an abnormal configuration (N-1 condition) and increases the risk of not being able to respond to another failure. Mobile substations allow for a means to resupply the load, during equipment replacement or repair, without putting any of the adjacent apparatus in jeopardy in the event of a secondary contingency.

c. Yes. In some cases, the addition of large-scale distributed energy resources ("DER") requires the upgrade and/or the addition of substation assets, which might include construction of a new substation. Certain substation components, including power transformers, have lead times of 2-3 years. Mobile substations can be used to temporarily interconnect new DER to the electrical system while upgrading or constructing the permanent solution. It is important to note that DER installations with a nameplate rating larger than the mobile substation will need to be limited to the nameplate rating of the mobile substation installed.

d. The Company has not identified any federal support programs related to reliability improvements that would provide support for the procurement of these mobile substations.

BENEFITS OF USING MOBILE TRANSFORMERS AND MOBILE SUBSTATIONS FOR RAPIDLY RESTORING ELECTRICAL SERVICE

A REPORT TO THE UNITED STATES CONGRESS PURSUANT TO SECTION 1816 OF THE ENERGY POLICY ACT OF 2005



August 2006

U.S. Department of Energy

The Secretary [of Energy] shall conduct a study of the benefits of using mobile transformers and mobile substations to rapidly restore electrical service to areas subjected to blackouts as a result of —

(A) equipment failure;
(B) natural disasters;
(C) acts of terrorism; or
(D) war.

Not later than 1 year after the date of enactment of this Act, the Secretary shall submit to the President and Congress a report on the study….

— Sec. 1816, the Energy Policy Act of 2005 (enacted August 8, 2005)

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Executive Summary

Section 1816 of the U.S. Energy Policy Act of 2005 (EPACT)[1] calls for a study on the benefits of using mobile transformers and mobile substations (MTS) to rapidly restore electrical service to areas subjected to blackouts as a result of equipment failure, natural disasters, acts of terrorism, or war. The law requires submittal of a report on the study to the President and Congress, not later than 1 year after EPACT's enactment.[2]

Background

MTS systems are used within a utility for a variety of reasons. Although MTS systems generally have larger losses and higher costs than conventional systems, their deployment capability (roughly 12 to 24 hours) is a major advantage to utilities. This flexibility allows them to be switched from one task to another relatively easily and is in fact a major justification for the utility to own and operate a MTS. Potential purposes for a MTS include planned maintenance, temporary increases in substation capacity, forced outage repairs, weather and other natural outages, and sabotage and attacks.

A MTS includes the trailer, switchgear, breakers, emergency or station power supply, a compact high-power-density transformer, and enhanced cooling capability. When needed, the MTS enables temporary restoration of grid service while circumventing damaged substation equipment, allowing time to procure certain long lead-time grid components.

Feasibility of Using MTS for "Rapid" Restoration of Electric Service

Weather and natural disasters are the main cause of electrical outages, most often by impacting the power lines leading to and from the substations, rather than disrupting the substations themselves. Yet, in those cases where a substation is affected, a MTS can be used by utilities to temporarily replace substation transformers in the low- and medium-power range (10-100 MVA). In general, MTS systems are too small to replace grid-critical high-power transformers (> 100 MVA), which represent approximately 5% of substation transformer applications in the United States.

Critical infrastructures and other facilities that require guaranteed electric service to function, such as the communications industry or first responders, generally need such service either instantaneously or within less than 5 minutes. MTS is capable of restoring substation operations in some cases within a 12-24 hour period. Thus, it is a delayed line of defense, falling behind uninterruptible power supplies, redundant rapid transfer to alternate power feed, and on-site generation. However, where disruption is prolonged due to equipment failure or total destruction from a war or act of terrorism, and especially where the problems are isolated to the substation, the MTS can play a critical role in reestablishing grid connection.

[1] Public Law 109-58, August 8, 2005.
[2] This report was prepared by the Secretary of Energy under the direction of the Office of Electricity Delivery and Energy Reliability. Technical support for the study was coordinated by B. McConnell, S. Hadley, and T. King, Oak Ridge National Laboratory.

Feasibility of using MTS for the Federal Government and Critical Infrastructures

The most obvious users of MTS systems within the Federal Government are the Federal electric utilities, such as the Tennessee Valley Authority, Bonneville Power Authority, and Western Area Power Administration. They currently use MTS systems for their own systems or those of their distribution utility customers. Similar to other utilities, power administrations use MTS systems for planned maintenance, temporary capacity increases, forced outage repairs, and weather and other natural outages.

Other possible government users are large military bases. However, most vital emergency power needs are usually already provided through on-site generators or redundant grid connections. Yet, the MTS systems can provide a tertiary line of defense to these critical facilities. Joint ownership of MTS systems may benefit both large Federal users of power and local utilities.

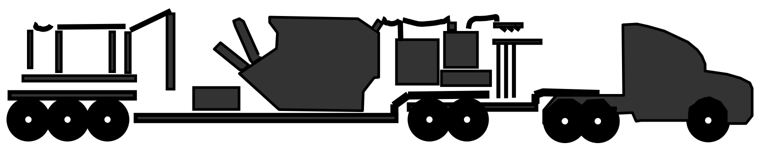
Although MTS systems can serve a vital role in restoration, the potential value of MTS systems for restoring electrical service to many critical loads is limited since it is very unusual to find a single critical infrastructure load greater than 3 MVA (lower limit for MTS viability) where standards, regulations, and emergency back-up procedures do not dictate either on-site back-up generation or alternate electrical feeds.

Feasibility of Reducing Dependence on Foreign Suppliers of Electrical Grid Components

Foreign producers dominate large-power transformer markets in North America, while medium-power transformers are essentially all produced in North America, with > 60% produced in the United States. Mobile systems currently fill the market need for temporary, medium-voltage transformers and substations (10-100 MVA). Large-power transformers (> 100 MVA) or higher-voltage transformers (>230 kV) are not currently replaceable using MTS, while transformers of 1-10 MVA size are generally available from multiple sources in a relatively short time period (2-3 days).

Since MTS are classed as low- and medium-power transformers, increasing or stockpiling MTS has no effect on the U. S. dependence on foreign production for large-power transformers. It also has little impact on the low- and medium-power transformer market, which is already supported by a domestic manufacturing capability.

Benefits of Using Mobile Transformers and Mobile Substations for Rapidly Restoring Electrical Service



1. Introduction

Section 1816 of EPACT calls for a report on the benefits of using mobile transformers and mobile substations (MTS) to rapidly restore electrical service to areas subjected to blackouts as a result of equipment failure, natural disasters, acts of terrorism, or war. (See Appendix A for the entire text of the section.)

This document is the report to Congress. DOE views the report requirements as consisting of two parts: the first, “an analysis of the feasibility of using mobile transformers and mobile substations to rapidly restore electrical power to military bases; the Federal Government; communications industries; first responders; and other critical infrastructures, as determined by the Secretary”, is addressed in Section 2 of this report; the second, “an analysis of the feasibility of using mobile transformers and mobile substations to reduce dependence on foreign entities for key elements of the electrical grid system of the United States”, is discussed in Section 3 of this report.

The report is further organized as follows:

- Section 2, in addressing the rapid restoration of electrical service, provides a broad overview of how transformers are used within the electric grid and the difference between stationary and mobile transformers. It also describes the applications for MTS systems and the rationale for their use.

- Section 3, in analyzing dependence on foreign suppliers, reviews the transformer market, including its overall size, domestic and foreign sources, the manufacturers involved, and other material and labor issues.

- Section 4 presents specific recommendations for the development of MTS systems that can serve a vital role in protecting the Nation’s electrical infrastructure.

2. Rapid Restoration of Electrical Service

2.1 Technology Overview

2.1.1 Description of Grid

The U.S. transmission grid is made up of power lines that operate at a wide range of voltages and power-carrying capacities. Figure 1 shows a simplified arrangement of the grid system in the United States. At the electric-generating plant, the three-phase power leaves the generator and enters a generator step-up (GSU) transformer located in the transmission substation, which is typically adjacent to the generator building. This substation uses large GSU transformers to convert the generator's voltage (which is at a nominal 25-kV level) up to high-level voltages (115 to 765 kV) for economical, low-loss, long-distance transmission on the grid.

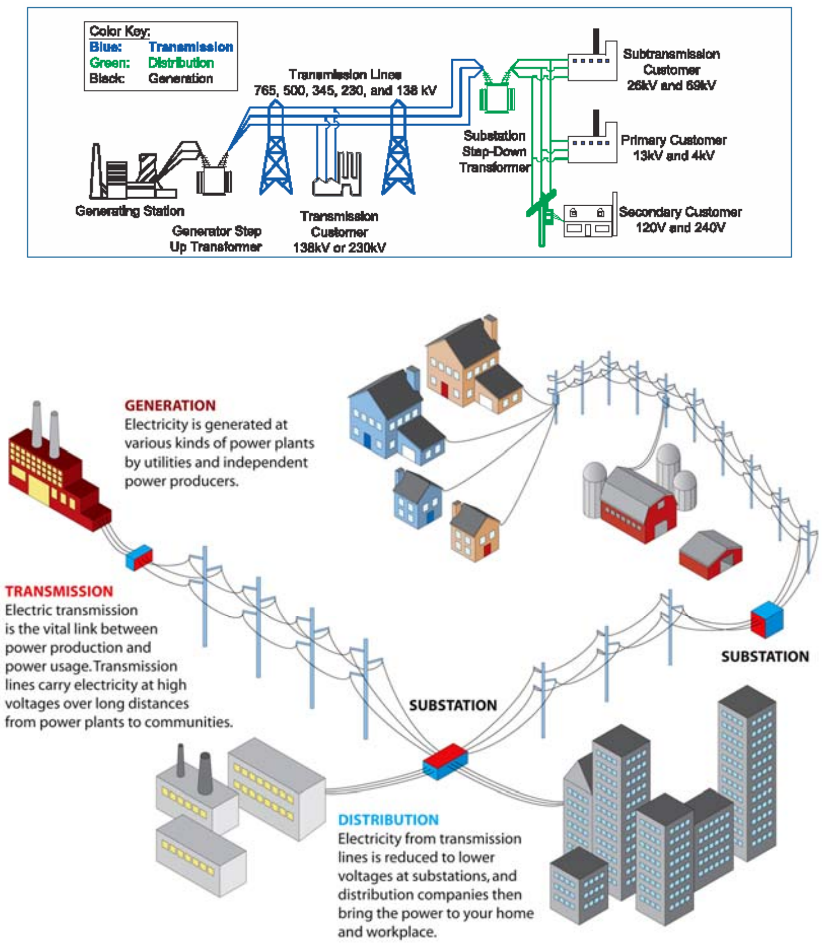


Fig. 1. Electric grid representation.

Following transmission, the voltage is stepped down at least once in order to distribute the power. Heavy industry may take power at transmission-level voltages, but most commercial and all residential service will have voltages stepped down at substations to the distribution voltages (2.5 to 35 kV). Finally, there are transformers mounted on poles or within the buildings to lower the levels even further for use by the end-users, typically 120/240 V, 280/440 V in residential and commercial end use.

At every point where there is a change in voltage, a transformer is needed that steps the voltage either up or down. There are essentially five levels of voltages used for transmitting and distributing AC power (Table 1): Ultra-High Voltage (UHV, 1100 kV), Extra-High Voltage (EHV, 345 to 765 kV), High Voltage (HV, 115 to 230 kV), medium (or sub-transmission) voltage (MV, 34.5 to 115 kV), and distribution voltage (2.5 to 35 kV). The UHV, EHV, HV, and MV equipment is mainly located at power plants or at electric power substations in the electric grid, while distribution-level transformers are located in the distribution network on poles, in buildings, in service vaults, or on outdoor pads.

Table 1. AC voltage classes

Transmission Voltages		Distribution Voltages	
Class	kV	Class	kV
Medium Voltage (MV)	34.5	2.5	2.4
	46	5	4.16
	69	8.66	7.2
	115	15	12.47
High Voltage (HV)	115	25	22.9
	138	35	32.5
	161		
	230		
Extra-High Voltage (EHV)	345		
	500		
	765		
Ultra-High Voltage (UHV)	1100*		

*1100 kV is not presently used in North America.

2.1.2 Description of Substation

A substation is a high-voltage electric system facility. It is used to switch generators, equipment, and circuits or lines in and out of the system. It is also used to change AC voltages from one level to another. Some substations are small with little more than a transformer and associated switches. Others are large with several transformers and dozens of switches and other equipment. The electricity flow through a substation is illustrated in Figure 2.

Source: OSHA

Fig. 2. Substation overview.

A typical substation is illustrated in Figure 3. Three transformers, each with a nominal 25-MVA rating, reduce voltage from 69 to 13.8 kV. Note the cooling radiators and bushings on the tops of the transformers; both are subject to damage during severe weather such as tornados or hurricanes. Such damage is often repairable in the field, and spare equipment is kept in inventory. In addition, the redundancy in this substation and sister substations a few miles away constitute modern utility practice in urban environments. This substation serves several shopping centers, an office park, and several residential subdivisions. The substation is relatively compact but has room for perhaps one additional transformer.

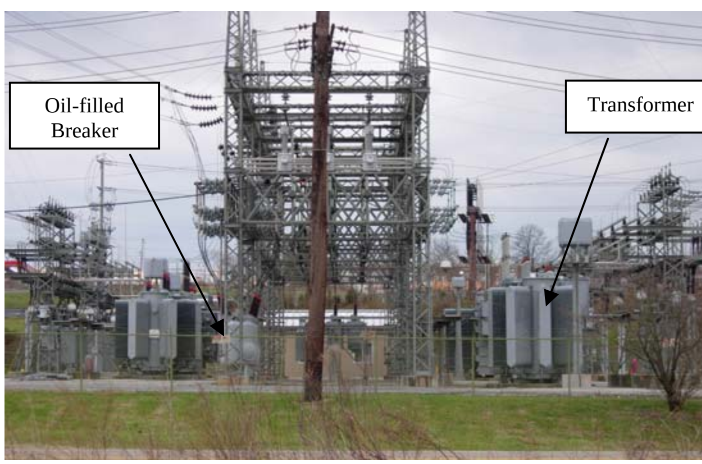


Fig. 3. A utility substation using modern oil-filled transformers.

In Figure 4, the two medium-sized, 3-phase, 161-kV power transformers each have an estimated oil natural-air-forced flow (ONAF) capacity of 50 MVA. The extensive cooling fans on the radiators indicate that this station expects a relatively high load during peak conditions (usually summer). This substation is one of the sister substations to the substation shown in Figure 3.

Should the need arise, there is adequate room for expansion and the placement of a MTS for maintenance or parallel service.

Fig. 4. A utility substation with both modern transformers and bus structure.

2.1.3 Types of Transformers

For transformers, the key parameter is more often the amount of power that can be transferred rather than the voltage. This parameter is measured in volt-amperes (VA) and incorporates both the real power (measured in watts) and reactive power (measured in volt-amperes reactive or VAR) because of the nature of the three-phase alternating current. Figure 5 identifies some typical customer power requirements. However, not all load within a facility is considered critical. While a hospital (especially trauma center) has peak load of 0.5-2 MVA and has full back-up generation, a semiconductor manufacturing plant may have only 1-2 MVA critical in a 30 MVA peak. A refinery or large chemical plant can easily have a load larger than 100 MVA, but would often generate its own electricity.

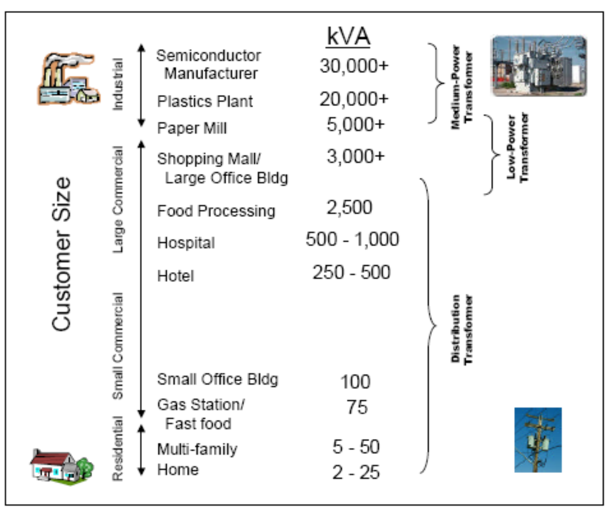


Fig. 5. Customer power requirements.

High-power transformers are defined as those with a rating over 100 MVA (megavolt-amperes), while medium-power transformers are between 10 and 100 MVA. Low- or small-power transformers are 1 to 10 MVA. The range of low-power transformers overlaps the large-distribution transformers (1 to 5 MVA), but low-power transformers have high-side voltages that are sub-transmission level or higher. Because of this overlap, estimates of small-power and large-distribution transformers may be "double counted" in inventories; hence, no reliable estimate of the number of these sized transformers is available.

Transformers with distribution voltage levels are also called distribution transformers and are commodity items. Distribution transformers are relatively small, ranging in size from "bucket size" to a few cubic meters (5 kVA to 5 MVA); they are easily replaced and are stocked for emergency purposes by both utilities and electrical supply wholesalers. Both liquid and dry types are used by industrial/commercial facilities. Because of higher efficiency, longer life, lower weight/volume, and predominant outdoor use, utilities employ essentially all liquid/oil transformers. Distribution transformers are not considered further in this report.

All power transformers are large, heavy, expensive, and generally use a paper/oil–based or hybrid paper/oil/solid insulation system. High-side voltage levels range from 35 to 765 kV. Prices for even the smallest units approach $100K, and several 100–200 MVA units easily sell for $1M. The large (up to 1100 MVA) GSU and HV transmission units are now approaching $3–5M or higher. Medium-power transformers for use in conventional substations have a nominal price of about $600K for a 50-MVA unit, but prices vary according to specifications, such as desired loss level and associated value of losses (A and B factors), impedance requirements, tap changers, cooling requirements, and accessories.

In high-load-density applications, transformers in most generating, transmission, and sub-transmission substations are installed or configured within the network in a manner that provides redundancy (so called N-1 and N-2 contingency). Within a substation, multiple units provide either parallel operation or allow for fast load transfer. In addition, there is often a spare in the substation or a system spare stored in a convenient central location. The latter method, however, requires the ability to transport (large units often weigh more than 50 tons and require rail transport and heavy lifting capability) and to install the spare at the required location, a process that can take several weeks. In lightly loaded suburban and rural areas, a substation may have only one transformer and essentially no contingency, which means that the load served is at risk of long-term outage if the substation or switchgear is damaged beyond repair. An example of this situation is provided later in this report.

Other distinguishing parameters of transformers are their insulation type (dry paper/oil based, also called liquid based, and hybrid liquid/non-paper systems), number of phases (one or three phase), adjustability (mechanisms for varying voltage and phase output), portability, core/coil configuration (shell or core form), and winding configurations (dual or auto). Transformation of power between voltages also requires extensive equipment such as disconnect switchgear, cooling systems, monitoring equipment, breakers, voltage adjustment equipment (tap-changing devices), and lightning arresters. Until recently, all medium- and large-power transformers were paper/oil or mixed insulation systems. A recent development by ABB allows the use of dry insulation for medium-power transformers (to 42 MVA) operating at 69 kV. This report only considers power transformers, specifically addressing mobile substations or portable transformers that nominally are rated at 5 to 100 MVA with HV ratings of 230 kV or lower.

2.1.4 Description of Mobile Transformers and Substations

In the usual stationary or fixed applications, the transformers, switchgear, protective systems, and station back-up power can be spread over a large area for insulating, safety, and maintenance purposes. In contrast, the mobile system is generally self-contained and mounted on a large trailer. Figures 6 and 7 show a typical mobile substation with some of the ancillary equipment. The units are generally mounted on mobile trailers (or possibly, in some special cases, on flatbed railcars). In most cases, special permits are still required to move the units because of the large weight. Differing state transportation load limits on non-Federal local roads further complicate the issue.

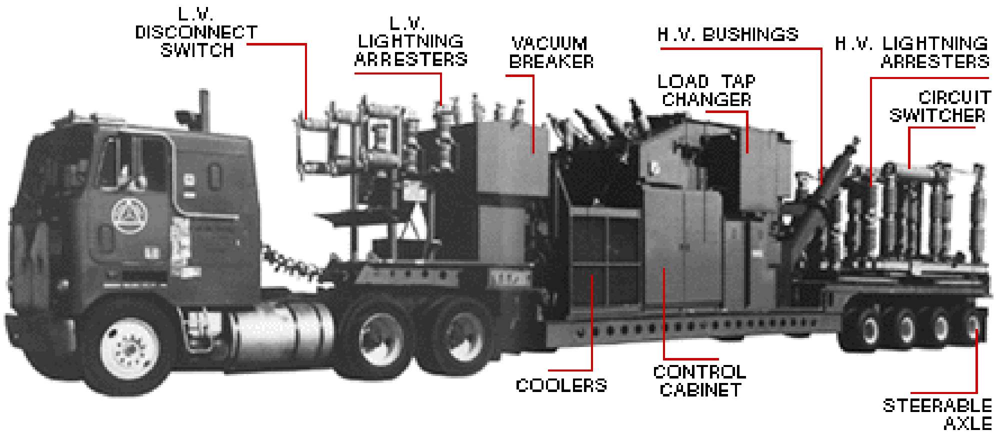


Figure 6. Components of mobile transformer.

Figure 7. Mobile substation in transit.

Mobile transformers are used by utilities to temporarily replace transformers that are out of service either for maintenance or because of forced outage. Mobile transformers are most widely available in the medium-power range (10 to 100 MVA) with HV ratings to 245 kV. Large-power transformers or higher-voltage transformers are too large to be mobile either because of physical dimensions or weight.

As described in the *Standard Handbook for Electrical Engineers* (Fink and Carroll, 1969), the mobile unit is designed to be a multi-purpose package delivering maximum kVA for allowable weight. Performance and design criteria vary considerably from those of a conventional transformer. The margin between the operating voltage level of the insulation structure (BIL) and the operating voltage is generally smaller, the average winding temperature rise over ambient is generally higher, the overload capability is less (*If only oil/paper is used. It should be noted that for modern Nomex® or hybrid systems, this is not true.*), and losses and impedance tend to be higher. The circuitry of the mobile unit is generally more complicated, in order to meet a variety of operating situations in a particular utility system.

Typical mobile transformer characteristics are shown in Tables 2 and 3. High-side voltages range from 35 to 245 kV with sizes ranging from 5 MVA to 100 MVA. Estimates by transformer manufacturers indicate that there are roughly 500 to 600 mobile transformers in service (slightly greater than 1% of the medium-power transformer inventory). Some of these transformers are quite old but are still serviceable because the number of hours that the mobile transformers are used is much lower than that of fixed installations. Because the mobile units operate at a higher power density than stationary units, losses are higher and, consequently, utilities use them only until a suitable stationary unit is obtained. According to manufacturers of mobile substations, the cost is about three times the cost of the fixed transformer alone. However, this includes the trailer, switchgear, breakers, emergency or station power supply, a compact high-power-density transformer, and enhanced cooling capability.

Table 2. Comparison of mobile and fixed transformers

	Mobile	Fixed
Insulation	Nomex®/Oil	Paper/Oil-Nomex®
Trise (°C)	Up to 115	65
Flux Density	1.78	1.5–1.75
Current Density	4 kA/cm²	0.25–0.5 kA/cm²
Loss Evaluation	No	Yes
Full Load Losses	1.5%	<0.5%
%Z	12–15%	<10%
Breakers	Yes	Substation
Switches	Yes	Substation
Auxiliary Power	Yes	Substation

Table 3. Mobile transformer characteristics

	Low	Nominal	High
MVA Rating	5	25	100
HV (kV)	35	115	245
LV (kV)	5	15	115
Total Weight (1000#)	50	95	150

2.2 Mobile Applications

2.2.1 Rationale for Use of Mobiles

Many of the critical infrastructures in this country rely heavily on electric power for their continued operation. Certain infrastructures, including the communications industry, public health, and government services such as first responders in emergencies, have a crucial role to play in a rapid response to outages. However, the critical infrastructure that would deal most directly with MTS systems is the electric power industry, which owns and operates the substations in which MTS systems would be used to replace lost equipment.

The electrical grid is a tightly integrated network that requires precise operation of all components to safely and efficiently provide power to end users. While the vast majority of outages are due to power line failures, the grid is also highly vulnerable to disruption at substations, where multiple lines intersect. Because substations are nodal points, a single failure can impact a large number of end users. There are thousands of substations across the country, and in any year, transformers at some of these will fail or be pulled from service. Unexpected failures can seriously disrupt the grid in the surrounding territory. As indicated earlier, there is usually sufficient redundancy in the system to withstand most single-transformer failures; however, substations serving low-load-density areas may not have sufficient contingency to overcome the loss.

MTS systems are used for a variety of reasons within a utility. However, the losses and costs associated with these systems are generally too high for them to be used as long-term replacements. In addition, MTS systems have lower impedance, which results in higher fault currents, leading to greater stress on grid components such as breakers. Rather, utilities utilize MTS systems for their main advantage—their rapid deployment capability (roughly 12 to 24 hours). Their flexibility allows them to be switched from one task to another relatively easily and is in fact a main rationale for a utility to own and operate a MTS. The potential purposes of an MTS include the following:

Planned maintenance
Temporary substation capacity increases
Forced outage repairs
Weather and other natural outages
Sabotage and attacks

Planned Maintenance

MTS systems are used on a day-to-day basis within the utility to provide alternate capacity during planned maintenance of substations. Because it is desirable to have MTS systems available for emergency duty during peak loading or extreme weather conditions, utilities schedule their planned maintenance around the time when MTS systems are less likely to be needed for emergency use. Since the utility will have only a limited number of MTS systems, substation repairs must then be staggered or delayed due to unplanned substation transformer outages.

Temporary Substation Capacity Increases

MTS systems may be called upon when an area may be faced with a temporary load increase that is not expected to last more than several months or perhaps a couple of years. Examples are construction projects or major plant modifications that require high electrical loads that will drop following completion. Special events can boost the capacity needs for a short time period. An MTS can be used to avoid the cost of a permanent upgrade that would rarely be used. Another example is to rapidly provide increased substation capacity during peak load conditions prior to substation upgrades, in the case where equipment deliveries were delayed or other problems arose that slowed the capacity expansion.

Forced Outage Repairs

One of the main areas in utility systems where MTS systems could reduce vulnerabilities is in medium-voltage rural areas without redundancy. Often the grid in these areas is topologically in a radial arrangement that does not allow for the redundancy of parallel circuits. Loss of a substation or even a key transformer within the substation can cause significant supply problems downstream. The Dyersburg example described in Sect. 2.2.3 shows the social and economic impact of the loss of a substation in regions that do not have multiple feeds.

Unplanned repairs can be called for due to existing equipment failure, weather phenomenon, or intentional disruptions. Equipment failure is the most common rationale for deployment. Lightning can cause a delayed failure or accelerate the aging of critical elements of the transformer. As transformers age, an increasing percentage of them can face sudden failure. Utilities attempt to monitor transformer conditions such as oil chemistry or load profiles to predict impending failure, but for many reasons, unexpected failures can still occur.

Subsequent to forced outages there are startup issues that should be addressed. The IEEE *Recommended Practices for Emergency and Standby Power Systems for Industrial and Commercial Applications* (IEEE, 1987) contains words of caution in the section on startup power. Paragraph 3.3.6 applies to all mobile equipment of all types in emergency situations: "Mobile equipment may suffice if it can be reasonably assumed to be available when needed. (Who has the highest priority when all have the need?)" Section 4.5.6 of the same standard suggests rental equipment as a viable alternative if mobile power is found to be too expensive (IEEE, 1987).

Weather and Other Natural Outages

Weather and natural disasters are the main cause of electrical outages, although most often these have a larger impact on the power lines leading to and from the substations than on the substations and transformers themselves. Some natural disasters can harm substation operations and create a need for MTS systems. The most likely are intense thunderstorms and tornados. Tornados are powerful enough that if they strike a substation, the equipment will generally be destroyed and require replacement. Floods also can cause massive damage either from the force of the water or shorting out and thus damaging equipment. It is generally flooding or flying debris that causes damage during hurricanes since substations can be designed to withstand hurricane-level winds.

Sabotage and Attacks

Intentional disruptions such as sabotage could severely harm our Nation's electrical grid, and most substations are very vulnerable to attack. Substations are usually unmanned, remote, exposed, and have few physical barriers. Utilities rely more on redundancy of the grid for mitigation rather than on hardening of individual sites. The larger sites frequently have personnel and improved protections, but the consequences of loss of these large sites are comparatively greater as well. There are few options available for the replacement of a destroyed high-power transformer. While MTS systems as large as 100 MVA exist, MTS systems are typically below 50 MVA in size, with high-side voltages not exceeding 230 kV. High-power transformers, as described above, are greater than 100 MVA and can have high-side voltages of 345 kV or higher and at present can not be backed up by MTS.

MTS systems can play a crucial role in several scenarios involving deliberate attacks. The ultimate target may be a critical infrastructure with limited access to electric power through just one or two medium-power substations. If the facility is vital to area health or other social needs and its substation links are destroyed, MTS systems may be useful in returning the facility to normal operations more quickly. This may be especially true if the attack strikes several substations, perhaps in order to bring down portions of a large urban area. The choice the utility must make is generally between mobile substations and either fixed or mobile emergency generation. Even with the use of emergency generation, small mobile transformers may be called upon to adjust voltages in the area, or to mitigate prolonged disruption.

2.2.2 Industry Experts' Interviews

A number of utility personnel and consultants were interviewed to determine the appropriate role that MTS systems play within their company. They identified the categories above as potential uses for MTS systems, with the main use being substation repair and maintenance. Construction and maintenance schedules are based on the availability of their MTS, and any delays can cause a domino-like rescheduling of other work.

The utilities may share their equipment within their own distribution utilities, but there did not appear to be much sharing of the equipment with other utilities. In some cases, they lease equipment to preferred customers at reasonable rates. One utility representative mentioned that a transformer serving a coal mine within his utility's territory had failed and that a MTS was used to provide continued operation.

One consultant familiar with the industry noted that MTS systems had been used for rebuilding and construction in substations, as temporary substations during construction of a new substation, for handling temporary loads that are transient in location like highway construction, and in military applications. Temporary substations had also been needed for new developments where line construction and new substations are behind the budget curve (sometimes for several years). Other utility representatives indicated that mobile systems were used for transformer failure replacements (up to 6 months), feeding isolated areas where service may be curtailed at a later date. A consultant noted that in areas hit by disasters like Hurricane Katrina, these units "are a Godsend." Since large-utility-class transformers require a 6-month to 1-year lead time in a normal economic environment, mobiles are very helpful in these situations.

2.2.3 Examples of Uses of MTS

Dyersburg, Tennessee

Rural areas typically have electric load density that is both lower and less critical than urban areas. Often substations will have only a single transformer or at best a set of four single-phase units that provide back-up for a single-phase failure. In addition, these rural areas are a radial configuration, which often means that substations have no redundant substation. In April 2006, a set of tornados swept through the area surrounding Dyersburg, TN resulting in major damage to one substation in the area near New Bern, TN. As shown in Fig. 8, the substation, a 161/13.2 kV, 10/13/16 MVA unit, was completely destroyed leaving the town of New Bern and a nearby industry without power, idling some 900 employees. Service was restored using a mobile transformer from the TVA while a new substation is constructed. (Smith-King of *Jackson Sun*, Photo and data from Patterson (TVA), Nashville Electric Systems)

Fig. 8. Biffle Road substation tornado damage, near Dyersburg, Tennessee.

Coleman National Fish Hatchery, California

On July 9, 2003, with temperatures in the Central Valley of California topping 100°F, a transformer failed at the Coleman National Fish Hatchery south of Redding. As planned, the emergency back-up generators kicked in to supply power, and Western Area Power Administration crews immediately began efforts to repair the transformer but were unsuccessful. Western maintains the power facilities that serve the hatchery under a contract with the Bureau of Reclamation; the U.S. Fish and Wildlife Service operates the hatchery. The hatchery releases about 12 million fall-run chinook salmon smelts, 1 million late-fall-run chinook, and 600,000 steelhead trout each year. The steelhead trout is on the threatened and endangered species list, and the chinook are possible candidates for the list. The two diesel back-up generators that were used burned 766 gallons of diesel a day, an additional expense and source of air emissions. On July 14, Western decided to install a mobile substation housed at the nearby Olinda Substation.

On July 15, the mobile substation was delivered to the hatchery. Maintenance crews started connecting the Pacific Gas and Electric (PG&E) power lines to the mobile substation and the lower-voltage lines from the mobile substation to the hatchery equipment. By July 16, the mobile substation had been connected, but crews encountered problems when it was energized. Fortunately, those problems were resolved, and the mobile substation was carrying the hatchery load by the afternoon of July 17. The mobile substation, mounted on a 60-foot flatbed, included a transformer that could be set for the 60- to 12-kV voltage change needed at the hatchery.

Fig. 9. Coleman National Fish Hatchery *(Source: FWS)*.

Chicago Loop

On April 13, 1999, subbasements in the Downtown Loop of Chicago, Illinois, were flooded due to construction in tunnels under the Chicago River. Power was shut off at the substations to avoid shorting out the systems. In response, businesses rented numerous diesel-generating sets to provide power to individual buildings. Patten Power Systems alone provided 35 generating sets representing 15 MW of power. Some locations also brought in mobile transformers to allow the transformation of power from emergency generators to lower voltages needed within the buildings. However, these transformers were of distribution-level size, in the 500-kVA range, rather than the larger MTS systems.

Sturgis, South Dakota

Black Hills Corporation in Rapid City, South Dakota, provides power for the western South Dakota region. Included in their territory is Sturgis, South Dakota, where for 1 week each summer the Sturgis Motorcycle Rally is held. This enormous gathering of motorcycle riders from around the country can expand the population of the town from 6,400 to over 500,000. A representative of the Black Hills Corporation has said that they use an MTS to increase the power capacity during this time.

Vermont Electric Power Company

Vermont Electric Power Company, which provides transmission service to several area distribution utilities, maintains an MTS system for use in its region. In designing the mobile system, locations and road approach limitations to substations had to be taken into consideration so that the vehicle carrying the mobile system would have adequate clearance. Figure 10 shows a typical arrangement for an MTS system at one of the substations (Wright, 2003). This 115- to 39-kV substation has a single transformer and would need an MTS system to be back online quickly. The utility had purchased a transportable 50-MVA transformer in 1974. In 2001, they redesigned the truck and support equipment to make it more mobile and easier to set up in the event of a power emergency.

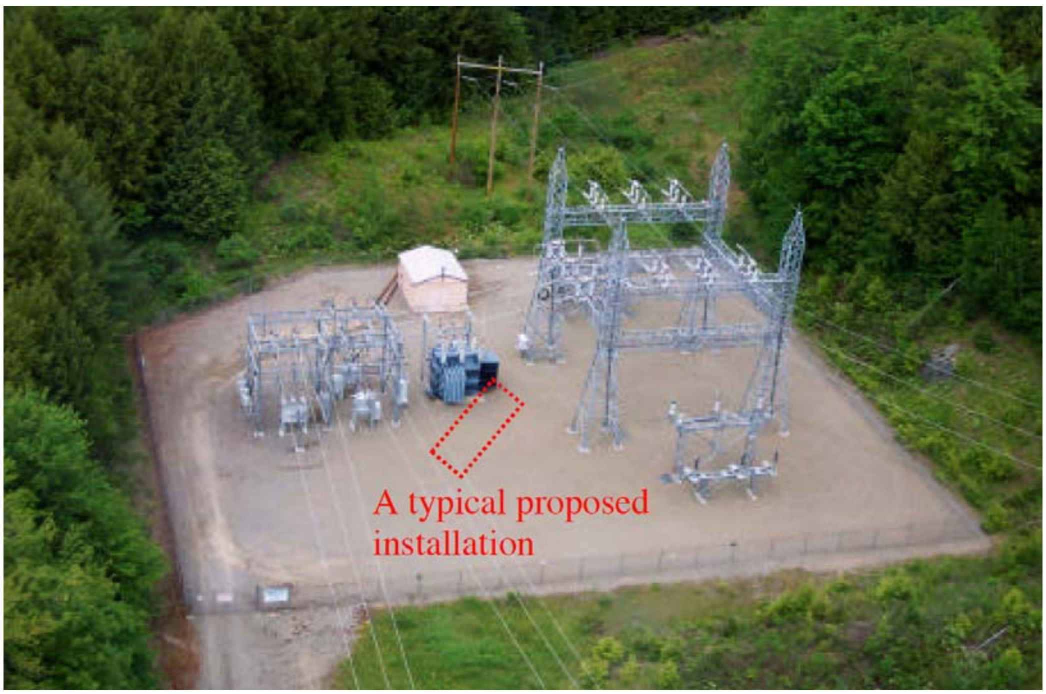


Fig. 10. MTS proposed position within Vermont Electric substation.

2.3 Potential Applications in Government

The most obvious users of MTS systems within the Federal Government are the Federal electric utilities, such as the Tennessee Valley Authority (TVA), Bonneville Power Authority (BPA), and Western Area Power Administration (WAPA). These utilities currently use MTS systems for their own systems or those of their distribution utility customers. They may either directly own the systems or have agreements with their distribution utility customers that allow them to use the systems as needed. The Dyersburg and Coleman National Fish Hatchery case studies, discussed in section 2.2.3, are examples of MTS use by TVA and WAPA.

MTS systems are a small fraction of the overall transformation capacity. They cannot be expected to supplant a large fraction of total government transformation requirements. The highest priority government functions already have in place on-site generation and/or redundancy in connections to the grid. The MTS systems can provide a tertiary line of defense to the critical facilities.

2.3.1 Military Bases

Military bases can have power systems that are about as large as a town. The systems are often old and yet in some cases could be critical to our Nation's national security. In the 1990s, Congress established a policy for privatization of the utilities at military bases. As a consequence, many of the systems have been sold to contractors or the local utilities.

The Department of Defense Energy Security Policy since 1992 has stated the following:

> Policy: It is a basic responsibility of Defense managers and commanders to know the vulnerability of their missions and facilities to energy disruptions, whether the energy source is internal or external to the command. Lastly, it is essential to take action to eliminate critical energy support vulnerabilities. (Morales, 1992)

According to the Department of the Army's Installation Management Agency (Wilberger, 2004), military facilities are required to develop energy security plans for their facilities, which should be integrated into the installation security plans.

> In general, these energy security plans should address utility system vulnerability, emergency preparedness requirements, and remedial actions needed to protect against potential problems. Energy security plans should be consistent with the Army's strategy to privatize utilities and reduce the cost of operating and maintaining the utility infrastructure. Installations should clearly define their utility requirements and partner with their local utility suppliers to meet them. Any remedial actions that run counter to utilities privatization, in terms of ownership and operation, must be approved by ASCIM [the Assistant Chief of Staff for Installation Management]. (Wilberger, 2004)

Based on these directives, military facilities are to work with their local utilities in ensuring that adequate infrastructures are in place. Rather than own and maintain its own utility equipment, the strategy is to encourage the privatization of infrastructure. Because the substation and downstream infrastructure on the bases would be owned by the local utility and if MTS were deemed necessary in specific cases to ensure energy security, it could be advantageous for both the military and the utility to jointly invest in an MTS system. The military base may be of such criticality that a spare substation/transformer would be useful, while having such a system mobile could also be advantageous to the utility since it would then be available in the event of other substation outages.

2.3.2 Other Federal Government

On Dec. 17, 2003, President Bush signed Homeland Security Presidential Directive (HSPD) - 7 that sets the policies of the Government with regard to critical infrastructure. The policy states the following:

> (7) It is the policy of the United States to enhance the protection of our Nation's critical infrastructure and key resources against terrorist acts that could:
>
> (a) cause catastrophic health effects or mass casualties comparable to those from the use of a weapon of mass destruction;
> (b) impair Federal departments and agencies' abilities to perform essential missions, or to ensure the public's health and safety;
> (c) undermine State and local government capacities to maintain order and to deliver minimum essential public services;
> (d damage the private sector's capability to ensure the orderly functioning of the economy and delivery of essential services;
> (e) have a negative effect on the economy through the cascading disruption of other critical infrastructure and key resources; or
> (f) undermine the public's morale and confidence in our national economic and political institutions.
>
> (8) Federal departments and agencies will identify, prioritize, and coordinate the protection of critical infrastructure and key resources in order to prevent, deter, and mitigate the effects of deliberate efforts to destroy, incapacitate, or exploit them. Federal departments and agencies will work with State and local governments and the private sector to accomplish this objective. (White, 2003)

Furthermore, HSPD-7 directs all agencies to address the vulnerabilities within their own domain.

> (24) All Federal department and agency heads are responsible for the identification, prioritization, assessment, remediation, and protection of their respective internal critical infrastructure and key resources. Consistent with the Federal Information Security Management Act of 2002, agencies will identify and provide information security protections commensurate with the risk and magnitude of the harm resulting from the unauthorized access, use, disclosure, disruption, modification, or destruction of information. (White, 2003)

Similar to the military bases, most other components of the Federal Government are end-use customers for electric power, and are not involved at the level that would put them in control of substations where MTS systems would be applicable. Essential functions are supported by back-up generation. However, if there is a federal facility that is large enough to require a significant fraction of a substation's output, has a critical need for power, is isolated on the grid, does not have uninterruptible power supplies, redundant transfer to alternate power feeds or on-site back up generation, and that a spare transformer would significantly increase their energy security, then a joint ownership agreement of an MTS with the local utility could be considered. As with the military base example, the MTS would be useful to the facility for redundancy and of potentially more value to the utility than a spare transformer because of its mobility.

2.3.3 Communications Industry

In June 2006, the Federal Communication Commission released a report on the impact of Hurricane Katrina on telecommunications and media infrastructure. While the panel's report emphasizes the severe damage the storm and its aftermath caused to communications systems, it also found that the utility communication systems did not have a significant rate of failure because: 1) the systems were designed to remain intact to aid restoration of electric service following a significant storm event; 2) they were built with significant on-site back-up power supplies (batteries and generators); 3) last mile connections to tower sites and the backbone transport are typically owned by the utility and have redundant paths; and 4) the staff responsible for the communications network have a focus on continuing maintenance of network elements (for example, exercising standby generators on a routine basis). (Section 1(A)(9))

Telephone systems (and now most cell sites) do not depend on the grid to function. While MTS systems may play a role in defending against prolonged outages, they fall behind uninterruptible power supplies, redundant transfer to alternate power feeds, and on-site generation as the tools of choice for guaranteed electric service immediately after a disruption.

2.3.4 State and Local Government / First Responders

State and local governments are responsible for initial recovery following a disaster. First responders include the local police, fire, emergency medical services (EMS), and state highway patrols. Typically, the facilities of the first responders have internal redundant power systems (if critical enough) or back-up generation to enable them to function as long as fuel is available. These organizations would not directly deploy MTS systems, but rather would assist the local utility in its restoration efforts. MTS systems would be most helpful in restoring power to broader, less critical facilities. However, there may be occasions in rural areas where multiple critical first-responder facilities are on a non-redundant distribution system, so the substation feeding the line may have a priority need for an MTS.

3. Reducing Dependence on Foreign Suppliers

3.1 Market Characteristics

In determining the feasibility of utilizing MTS systems to reduce dependence on foreign suppliers, it is important to understand current market conditions and characteristics of the transformer industry. Several key questions will be addressed, including the following:

- What is the overall size of the transformer market?
- How many units are installed and who manufactures them?
- How many transformers need to be manufactured each year?
- What is the relationship between the U.S. market and the worldwide market?
- How much of the market is domestically produced?
- What is the market for MTS systems as one component of the overall transformer industry?
- What are the material and other supply limitations?

3.1.1 Size of Transformer Market

Peak electricity demand in the United States in 2004 was 700 GW (NERC, 2005). Assuming that an average of 2.5 medium- or large-power transformations are required from power plant to distribution system and an average size of 35 MVA per transformer, this suggests that there are roughly 50,000 high- and medium-voltage transformers in the United States. The total size of the installed transformer base is shown in Table 4. Looking at historical power demands and applying the formula above on the estimated number of transformers needed, the total number of transformers required in the future is expected to increase. In the past several years, power transformer sales have lagged behind electric growth as the industry adjusted to deregulation. Combining new demand and replacement of failures, one could expect a growth in transformer sales of 4% in future years, and sales figures for the recent past support this conclusion.

Table 4. National transformer statistics (best engineering estimates)

	Voltage range (kV)	Power range (MVA)	Number	Average age
Large Power	115–765	200–1200	2500	40+
Medium Power	65–345	10–100	45000	35+
Low Power	35–69	1–10	5000	25+
Mobile Power	35–245	1–100	600	20+

Given a total installed market of 50,000 transformers, a 2% growth rate in electricity demand would require an additional 1000 transformers each year even without a replacement market. (Ref. Manufacturer Communications)

In addition to normal load growth, transformers are also needed to replace failures in the existing inventory. Power transformers are generally considered to be long lived. Utilities routinely depreciate them over 20 years for accounting purposes and use 30-year periods in planning analysis. However, Bartley and James estimate that units may be failing earlier in life than conventional wisdom indicates, with average life at failure being about 14 years for all applications and 18 years for utilities (Bartley 2003a). However, the average age of the presently installed units is over 40 years, and there are some in use that are over 70 years old. The age issue and predicted increase in failures (Bartley 2003a) suggest a possible need for mobile transformers for emergency and maintenance support. These MTS would temporarily supply load following failures or assist heavily loaded substations during peak conditions, thereby lowering the stress placed on older units.

Figure 11 shows the annual installation of transformer capacity through 1996 (Bartley 2003b), and Fig. 12 shows an analysis of the failure rate of transformers as a function of age (Bartley 2003a). This data would indicate that failures may be occurring earlier than anticipated, and hence production beyond the nominal growth rate may be needed.

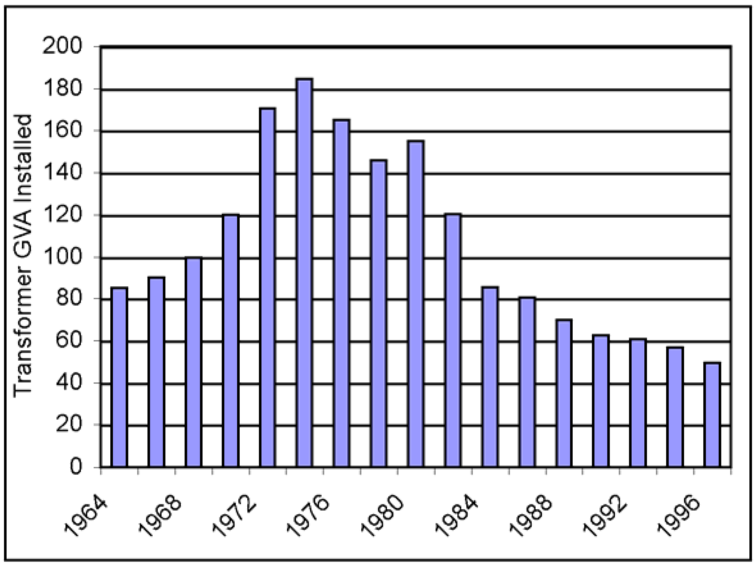


Fig. 11. Gigavolt-ampere (GVA) of transformer installations by year.

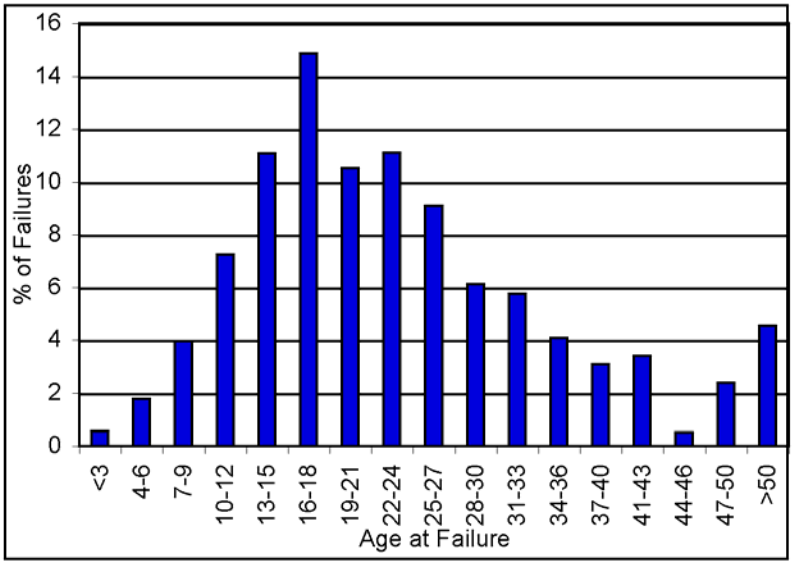


Fig. 12. Age of transformer at failure.

Combining the failure projections from Bartley's paper with continued installations of only 25 GVA/year between 1996 and 2006 (consistent with the 1996 installation amount) and failures based on Fig. 12, the resulting level of failures in GVA is shown in Fig. 13. At 4.9 GVA of transformer failures in 2006, the country would need 140 additional 35-MVA transformers in addition to the 1000+ needed for new growth, and, as seen in Fig. 13, these amounts will continue to grow.

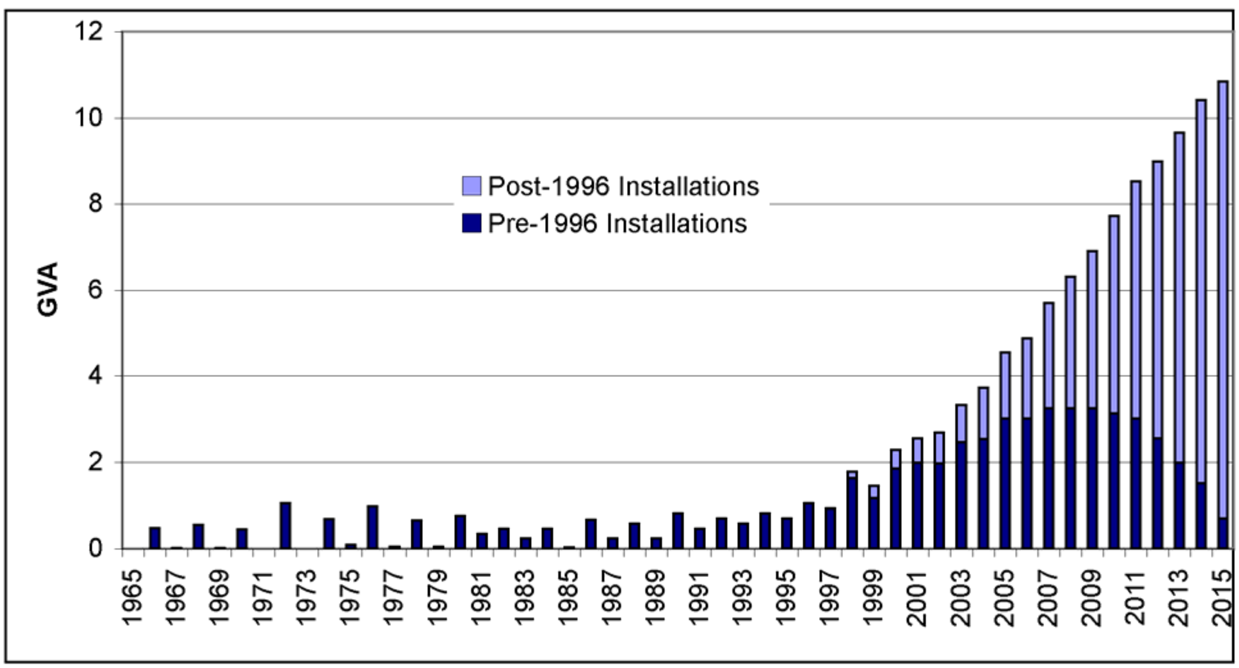


Fig. 13. Failure projections.

Although the U.S. annual market for transformer sales is 1100 to 1200 per year, MTS systems will only be a fraction of that total. Current MTS markets are limited due to the cost and inefficiencies of the systems compared with non-mobile equipment. While MTS systems are extremely valuable when rapid restoration or other short-term service is required, they are not viable replacements for stationary substations. Currently, there are an estimated 600 MTS systems in an overall U.S. market of around 50,000 transformers, or 1.2%. As increasing numbers of transformers age and fail, and as electric reliability becomes more critical to the Nation's economy, the use of mobile transformers in proportion to total transformers could increase.

3.1.2 Breakdown of Market by Manufacturer

The main manufacturers of medium-power transformers are Waukesha Electric Systems, Kuhlman Electric, ABB, GE Prolec, and Delta Star, while ABB, VA Tech, GE Prolec, Hyundai, Seimens, HICO, and Pauwels supply large-power transformers. Mobile substations are generally a subset of the low- and medium-power transformer market. Among mobile transformers, the major manufacturers are Delta Star, Pauwels, Kuhlman, and ABB, with Delta Star being the largest. Mobile transformers can either be built directly as mobile or, in some cases, older transformers can be refurbished and made portable.

Tables 5 through 8 quantify the North American transformer market. Over 80% of the medium–power transformer North American market is manufactured in the United States.

Table 5. Large-power transformer manufacturers

Company	% of North American market	Manufacturing location	
		United States	Offshore
ABB	27–29	Y	Y (Worldwide)
Seimens/VA Tech	22–24	N	Y(Worldwide)
GE-Prolec	11–13	N	Y(Mexico)
Hyundai	10–12	N	Y(Korea)
HICO (Hyosung)	<5	N	Y(Korea)
Pauwels	<5	N	Y(Belgium)
Waukesha	<5	Y	N
VTC	<4	N	Y(Mexico, India)
Kuhlman	<3	N	Y(Mexico)
Mitsubishi	<2	N	Y(Japan)
PA Transformer	<2	Y	N
Areva T&D	<1	N	Y (France)
Compton Greaves	See Pauwels	N	Y(India)

Table 6. Medium-power transformer manufacturers

Company	% North American market	MTS	Dry (D) Liquid (L)	Manufacturing location	
				United States	Offshore
Waukesha	34–36	N	L	Y	N
Kuhlman	17–19	Y	L	Y	Y(Mexico)
ABB	15–17	Y	L, D	Y	Y (Worldwide)
GE-Prolec	11–13	N	L, D	Y	Y(Mexico)
Delta Star	9–10	Y	L	Y	N
VTC	<3	N	L, D	Y	Y(Mexico, India)
HICO (Hyosung)	<2	Y	L, D	N	Y(Korea)
PA Transformer	<2	N	L	Y	N
Pauwels	<2	Y	L, D	Y	Y(Belgium)
Schneider (Sq.D)	<2	N	L, D	Y	Y(France)
Seimens/VA Tech	<2	Y	L, D	N	Y(Europe)
Compton Greaves	<1	N	L, D	N	Y(India)
Howard	<1	N	L	Y	N
Niagara Trans.	<1	N	L, D	Y	N
Hyundai	Y	Y	L, D	N	Y(Korea)

Table 7. Major low-power transformer manufacturers

Company	MTS	Dry (D) Liquid (L)	Manufacturing location	
			United States	Offshore
ABB	Y	L, D	Y	Y (Worldwide)
Delta Star	Y	L	Y	N
HICO (Hyosung)	Y	L, D	N	Y(Korea)
Hyundai	Y	L, D	N	Y(Korea)
Kuhlman	Y	L	Y	Y(Mexico)
Pauwels	Y	L, D	Y	Y(Canada)
Seimens/VA Tech	Y	L, D	N	Y(Worldwide)
Compton Greaves	N	L, D	N	Y(India)
Federal Pacific	N	D	Y	N
GE-Prolec	N	L, D	Y	Y(Mexico)
Howard	N	L	Y	N
Niagara Trans.	N	L, D	Y	N
PA Transformer	N	L	Y	N
Schneider(Sq.D)	N	L, D	Y	Y(France)
VTC	N	L, D	Y	Y(Mexico, India)

Table 8. Mobile transformer manufacturers

Company	Estimated % of MTS market	Plant location	
		United States	Offshore
Delta Star	50	Y	N
Pauwels	25	N	Y(Canada)
Kuhlman	10	N	Y(Mexico)
ABB	5	N	Y(Europe)
Howard	<1	Y	N
HICO (Hyosung)	<1	N	Y(Korea)
Hyundai	<1	N	Y(Korea)
Seimens/VA Tech	<1	N	Y(Europe)

Mergers of several major manufacturers continue. The VA Tech and Seimens merger has received the European Union's approval, and Compton Greaves has acquired Pauwels. In the medium-power area, Waukesha has expanded its plants in Waukesha, Wisconsin, and is now an active player in the large-power market with the capacity to build up to 420 MVA and 345 kV. The recent opening of Howard Industries' new medium-power transformer plant in Mississippi suggests an anticipated increase in product demand for the sector.

While the size range (10–100 MVA) suggests that the manufacturer of portable transformers and MTS is a subset of the general medium-power transformer sector, the MTS system is a very specialized application that requires careful engineering and fabrication techniques that are significantly different from those for a fixed substation. While all MTS manufacturers are also players in the fixed market, the reverse is not true. The major manufacturers in the worldwide MTS market, such as ABB and VA Tech/Siemens, are not active in the North American market, but an increase in MTS demand could encourage them to enter.

Mobile transformers can be either single or three phase, and the unit may be the transformer alone (a portable transformer) or the complete substation package with breakers, tap changers, protective equipment, station power (battery and generator), and trailer.

In addition to the new transformer market, there are a few suppliers of used or rental transformers. Included are both low- and medium-power transformers and MTS. Guaranteed delivery times and lists of available inventory enable utilities and industry to preplan for forced outage replacement with guaranteed availability for these suppliers. Some of the players in this market are Aggreko/Sunbelt, Power Asset Recovery, GE, and Midwest.

3.1.3 Domestic as Compared to World Market

The world market for electrical equipment ($30.8B) is dominated by ABB, with a 23% share of world power products (Ref. ABB). For transformers, a $14.8B world market, the key manufacturers are ABB with 21%, Siemens with 11%, Areva with 6%, and Schneider with 6%. The power transformer share of the world transformer market is about 30%. This suggests that the present North American market is about 20% of the world's total power transformer market.

The ABB global market summary identifies the major issues for the electric grid. For North America and South America, there is an aged infrastructure that needs to be refurbished. In the United States, reliability concerns and passage of EPACT may trigger T&D investments. In Northern Europe, Central Europe, and the Mediterranean, there is a need for interconnections and power-grid upgrades that will require replacement and refurbishment. The power systems of the world are experiencing the highest growth in North Asia and China where continued strong government commitment to power infrastructure is creating the prospect of the world's most modern power grid. Also in South Asia and India, rural electrification is increasing demand for power distribution products and systems with a trend for quality and branding. In the Middle East and Africa, the oil and gas sector is the main driver for power T&D.

The largest and fastest growing part of the power transformer market is in China, India, and Asia. In fact the world's largest power transformer plant is located in Chongqing in central China and is being built by a consortium of ABB, Siemens, and the Chinese government. (Hein) This plant is one of the People's Republic of China's flagship factories, and not only will it be the world's largest transformer plant, it will also have the world's largest transformers, which are also being built by ABB. These units are supplied to the power plant at the Three Gorges Dam. ABB has stated that while the plant is not dependent on the production volume for the Three Gorges, it is supplying the 12 gigantic transformers for the right wing of the power plant at the dam. The average output of each transformer is 840 MVA, which is enough to supply a large modern city. Siemens and a Chinese vendor provide the 14 transformers on the other side of the project.

Mobile systems currently fill the market need for temporary, medium-voltage transformers and substations. Because they do not directly compete against foreign (or domestic) manufacturing of stationary transformers, mobile transformers, to some extent, complement foreign manufacture of stationary transformers because they provide a short-term solution until the foreign or domestic stationary transformer is delivered. The difference in travel time for domestic versus foreign-made transformers may only be a small factor in the overall time to receive the product. Price and proven performance are the two major issues for purchasers of power transformers.

3.1.4 Material and Labor Supply Issues

The main materials required in the manufacture of a transformer are the low-loss, high-silicon steel used for the core, the copper used for the windings, and the insulating materials.

Electrical steel, or silicon electrical steel, contains relatively high amounts (3 to 4.5%) of silicon. This addition enhances certain magnetic properties, leading to lower losses and high permeability. It is usually in the form of cold-rolled strips, called laminations, that are less than 2 mm thick.

There are two main types of electrical steel, grain oriented and non-oriented. Grain-oriented electrical steel usually has a silicon level of 3% and is processed in such a way that the optimum properties are developed in the coil rolling direction. Power transformers use grain-oriented steel to reduce losses. Electrical steel is usually coated to increase electrical resistance between laminations to lower eddy currents and to provide corrosion resistance. Main domestic suppliers of electric steel are AK Steel and Allegheny Ludlum. Electrical steel is also available from Japan, India, China, and the European Union. Variation in electrical steel prices can cause large fluctuations in transformer prices.

While aluminum windings are found in distribution transformers, the lower losses and physical properties of copper make it the only real choice for power transformer coils. Copper is a commodity that is traded on world markets, and as with electrical steel, the price of copper strongly influences the cost of power transformers. According to the Copper Development Association, Chile is the world's largest producer, followed by the United States. The major producers of the wire used in transformers (magnet wire) are Phelps-Dodge and Algonquin Industries Division of Rea.

Several major corporations supply insulating materials. The key players are Weidmann Electrical Technology and Dupont. Dupont is the only supplier of the high-temperature insulation system Nomex® that is used alone and with paper/oil hybrid insulation systems for high-power-density, high-temperature operations.

Various analyses by manufacturers and independent market analysts have determined that there is a current and increasing shortage of basic transformer materials, namely, transformer steel and copper. Manufacturers indicate that over a two-year period, prices for copper have risen to $4/lb, a 450% increase, while high-grade H1 core steel has increased 50% over the last year to a nominal $2.87/kg. Since copper and steel are the major portions of the cost, power transformer prices have risen very sharply. The major explanation for this is the increased demand for all transformer materials in the Asian market. Following the law of supply and demand, the two domestic transformer steel manufacturers are currently supplying a large portion of their spot market product to the Asian and Chinese markets.

The production of power transformers is a labor-intensive process, and labor costs constitute 8 to 12% of a power transformer's final cost. Power transformer manufacturers have moved many plants offshore to countries with low labor costs (Mexico, India, China, and Korea) that are also closer to the higher demand. While the technical skills needed are not commonplace, the workforces can be trained relatively quickly.

4. Conclusions and Recommendations

Rapid Restoration of Electrical Service

MTS systems can serve a vital role in protecting the Nation's electrical infrastructure. Their flexibility allows them to switch from one purpose to another relatively easily. When needed, the MTS enables temporary restoration of grid service while circumventing damaged substation equipment, allowing time to procure certain long lead-time grid components.

However, for seamless continuity of operation, it is critical that there is virtually a continuous supply of electricity. This can only occur through uninterruptible power supplies (e.g. batteries), redundant power feeds, and on-site generation. Yet, where disruption is prolonged due to equipment failure or total destruction from a war or act of terrorism, and especially where the problems are isolated to the substation, the MTS can play a critical role in reestablishing grid connections.

Supply for Prioritized Government Functions

Government facilities and local utilities know their systems' redundancy and needs. Local utility involvement is crucial since most components of the federal government are end-use customers for electric power and are not involved at the level that would put them in control of the substations where MTS systems could be applicable. For cases that have been identified through existing processes to have a need for additional redundancy and for which MTS systems make good economic and security sense, there may be some justification for the government to consider through single or joint ownership. However, because of the variety of ways emergency power can be provided, each case should be considered independently.

Regulatory

A fixed substation is considered part of the transmission and distribution (T&D) grid. Although mobile substations and mobile transformers are not a permanent part of the grid structure; they play a vital role in maintaining the reliability and security of a utility's grid system. The availability of mobile transformers and mobile substations enables system operators to rapidly restore electrical service where there is equipment failure, forced outage repairs, natural disasters, and acts of terrorism. When mobile transformers and mobile substations are used to restore electrical service in such situations, they function as part of the permanent grid system. In effect, they are an integral and critical part of the utility's electrical system. Accordingly, an investment in technologies like this to address reliability and security concerns may be prudent in today's operating environment and should not be discouraged simply because the technologies are unconventional.

Reducing Dependence on Foreign Suppliers

Foreign producers dominate large-power transformer markets in North America, while medium-power transformers are essentially all produced in North America, with > 60% produced in the United States. Mobile systems currently fill the market need for temporary, medium-voltage transformers and substations (10-100 MVA). Large-power transformers (> 100 MVA) or higher-voltage transformers (>230 kV) are not currently replaceable using MTS, while transformers of 1-10 MVA size are generally available from multiple sources in a relatively short time period (2-3 days).

MTS are classed as low- and medium-power transformers and has no effect on the U. S. dependence on foreign production for large-power transformers. The low- and medium-power transformer market is already supported by a domestic manufacturing capability. In addition, because they do not directly compete against foreign (or domestic) manufacturing of stationary transformers, mobile transformers, to some extent, complement the manufacture of stationary transformers because they provide a short-term solution until the foreign or domestic stationary transformer is delivered.

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Appendix A

Energy Policy Act of 2005, Section 1816

SEC. 1816. STUDY OF RAPID ELECTRICAL GRID RESTORATION

(a) STUDY—

(1) IN GENERAL—The Secretary shall conduct a study of the benefits of using mobile transformers and mobile substations to rapidly restore electrical service to areas subjected to blackouts as a result of—

(A) equipment failure;

(B) natural disasters;

(C) acts of terrorism; or

(D) war.

(2) CONTENTS—The study under paragraph (1) shall contain an analysis of—

(A) the feasibility of using mobile transformers and mobile substations to reduce dependence on foreign entities for key elements of the electrical grid system of the United States;

(B) the feasibility of using mobile transformers and mobile substations to rapidly restore electrical power to—

(i) military bases;

(ii) the Federal Government;

(iii) communications industries;

(iv) first responders; and

(v) other critical infrastructures, as determined by the Secretary;

(C) the quantity of mobile transformers and mobile substations necessary—

(i) to eliminate dependence on foreign sources for key electrical grid components in the United States;

(ii) to rapidly deploy technology to fully restore full electrical service to prioritized Governmental functions; and

(iii) to identify manufacturing sources in existence on the date of enactment of this Act that have previously manufactured specialized mobile transformer or mobile substation products for Federal agencies.

(b) REPORT—

(1) IN GENERAL—Not later than 1 year after the date of enactment of this Act, the Secretary shall submit to the President and Congress a report on the study under subsection (a).

(2) INCLUSION—The report shall include a description of the results of the analysis under subsection (a)(2).

Appendix B

List of Acronyms

AC	Alternating Current
BIL	Basic Impulse Insulation Level
BPA	Bonneville Power Authority
DC	Direct Current
DoD	Department of Defense
DOE	Department of Energy
DOT	Department of Transportation
DVP	Dominion Virginia Power
EHV	Extra-High Voltage
EMS	Emergency Medical Services
EPACT	U.S. Energy Policy Act of 2005
GSU	Generator Step-Up
GVA	Gigavolt-Ampere
HEC	Humphreys Engineer Center
HSPD	Homeland Security Presidential Directive
HV	High Voltage
kV	Kilovolts
KVA	Kilovolt-Ampere
MTS	Mobile Transformers and Substations
MV	Medium Voltage
MVA	Megavolt-Ampere
O&M	Operations and Maintenance
ONAF	Oil Natural-Air-Forced Flow
PG&E	Pacific Gas and Electric
R&D	Research and Development
RD&D	Research, Development, and Demonstration
T&D	Transmission and Distribution
TVA	Tennessee Valley Authority
UHV	Ultra-High Voltage
VA	Volt-Ampere
VAR	Volt-Ampere Reactive
WAPA	Western Area Power Administration

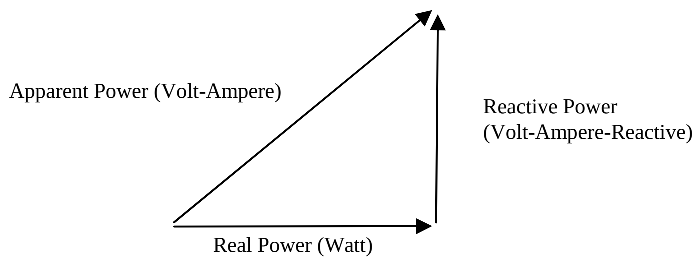
Appendix C

Electricity Glossary

Active Power: Also known as "real power". The rate at which work is performed or that energy is transferred, commonly measured in watts or kilowatts.

Alternating Current (AC): Current that changes periodically (sinusoidally) with time.

Apparent Power: The product of voltage and current phasors, usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA).



Blackout: Emergency loss of electricity due to failure of generation, transmission, or distribution.

Bulk Power System: All electric generating plants, transmission lines, and equipment.

Bus: Shortened from the word busbar, a node in an electrical network where one or more elements are connected together.

Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Circuit: A conductor or a system of conductors through which electric current flows.

Circuit Breaker: A switching device connected to the end of a transmission line capable of opening or closing the circuit.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical equipment.

Current: The flow of electrons in an electrical conductor measures in Amperes.

Demand: Amount of power consumers require at a particular time.

Direct Current (DC): Current that is steady and does not change with time.

Distribution Network: The portion of an electric system that is dedicated to delivering electric energy to an end user, at or below 69 kV.

Electrical Energy: The generation or use of electric power by a device over a period of time, usually expressed in kilowatthours (kWh).

Fault: Refers to some abnormal system condition, usually means a short circuit.

Generation (Electricity): The process of producing electrical energy from other forms of energy.

Generator: Generally, an electromechanical device used to convert mechanical power to electrical power.

Grid: An electrical transmission and/or distribution network.

High Voltage Lines: Used to transmit power between utilities. The definition of "high" varies, but it is opposed to "low" voltage lines that deliver power to homes and most businesses.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Power/Phase Angle: The angular relationship between an ac (sinusoidal) voltage across a circuit element and the ac (sinusoidal) current through it.

Protective Relay: A device designed to detect abnormal system conditions and initiate the operation of circuit breakers or other control equipment.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. It is usually expressed in kilovars (kVAR) or megavars (MVAR). Reactive power must be supplied to most types of equipment with windings, such as motors and transformers.

Real Power: See "Active Power".

Relay: A device that controls the opening and subsequent reclosing of circuit breakers.

Reliability: The degree of performance of the elements of the bulk power system that results in electricity being delivered to customers within accepted standards and in the amount desired.

Security: The ability of the electric system to withstand sudden disturbances.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches.

Transformer: A device that operates on magnetic principles to increase (step up) or decrease (step down) voltage.

Transmission: An interconnected group of lines and associate equipment for the movement of electric energy between points of supply and points at which it is transferred for delivery to customers or is delivered to other electric systems.

Voltage: The electrical force, or "pressure", that causes current to flow in a circuit, measured in volts.

Voltage-Ampere-Reactive (VAR): A measure of reactive power.

PUC 9-17
Meters (AMF/AMR)

Request:

With reference to RIE's response to CLF 1-5:

a. Please explain if RIE is replacing any failed or end-of-life AMR meters with advanced meters, other than in locations where planned AMF roll out is occurring. If not, why not?

b. Does RIE anticipate a reduction in the need to replenish AMR meter inventory in FY25 given the roll out of AMF? If so, please provide an explanation of how inventory volume and cost was reduced.

Response:

a. Rhode Island Energy is not planning to replace any failed or end-of-life AMR meters with AMF meters outside of the planned AMF meter deployment schedule. AMR meters are read utilizing a system not compatible with AMF technology, meaning any AMF meter set in a location absent the required RF mesh network would be subject to a manual read.

b. Rhode Island Energy anticipates a slight reduction in spend on AMR meters in FY 2025, and then a greater reduction in FY 2026 and FY 2027, aligning to the AMF meter deployment schedule. In FY 2025, Rhode Island Energy intends to perform the same required planned meter replacement activities and use the typical meter failure rate for unplanned meter replacements.

PUC 9-18
Meters (AMF/AMR)

Request:

With reference to the response provided in PUC 5-9, what function(s), if any, will the AMF network investments provide at locations where no meters have been installed?

Response:

The AMF RF mesh network investments will not provide any immediate functions at locations where no meters have been installed. The installation of network equipment, meaning gateways and routers, is a prerequisite to AMF meter installations. The RF network must be installed, commissioned and tested in order for AMF meters to communicate and send data back to the Head End system. Simplified, an AMF meter cannot communicate without the RF network.

Prepared by or under the supervision of: Parker Capwell and Philip Walnock

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PUC 9-19
Meters (AMF/AMR)

Request:

For each town included in the tables provided in Attachments to PUC 5-9, please provide a table with columns for:

a. The number of planned AMF meters to be deployed in the town in FY25,
b. The portion of the planned AMF network to be deployed in the town in FY25 that will serve AMF meter communication in FY25,
c. The same as part a for FY26, and
d. The same as part b for FY26.

Response:

Through and including this response, Rhode Island Energy is addressing updates to the Advanced Metering Functionality ("AMF") implementation schedule.

The primary reason for the AMF updates, which are included in this response, is the schedule shift of the final Transition Services Agreement ("TSA") exit date from National Grid USA's systems to PPL's systems moving from May 2024 to August 2024. The shift of the TSA exit date results in a shift of AMF timing and approach. Along with a needed update in the systems functionality release approach and schedule, meter deployment start will move from January 2025 to March 2025. There is no change to the timing of pre-sweeps and network deployment.

The secondary reason for the AMF updates is a result of finalizing or near finalization of vendor contracts, resulting in firm cost estimates. There is no change to the overall AMF program cost but the update does reduce FY2025 forecasted spend and increases FY2026 and FY2027.

a. Please see Attachment PUC 9-19-1
b. Please see Attachment PUC 9-19-2
c. Please see Attachment PUC 9-19-3
d. Please see Attachment PUC 9-19-4

The information reflected in the attachments is represented in ISR fiscal quarters.

Additionally, please see Attachment PUC 9-19-5, which is an updated Section 5, Attachment 3, which was originally filed as part of the Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan Filing (starting on Bates 277). The revised revenue requirement reflects the updated forecasted FY 2025 capital in service for the reasons described above, as well as

PUC 9-19, page 2
Meters (AMF/AMR)

reflecting 1) the corrected book depreciation rate for network investments as described in the response to PUC 2-3 and 2) the removal of MDMS costs from software rather than meters as was described in the response to PUC 4-5. On the attachment, the Company has highlighted the cells that have input changes from the originally filed revenue requirement. The Company did not highlight all of the flow through cells that changed.

Including this response, the AMF updates impact the Company's responses to the following data requests:

PUC Set 1
PUC 1-1, 1-2, 1-3, 1-4

PUC Set 2
PUC 2-1, 2-2, 2-4

PUC Set 3
PUC 3-1, 3-2, 3-3, 3-4

PUC Set 4
PUC 4-1, 4-2, 4-5, 4-6

PUC Set 5
PUC 5-5, 5-9

PUC Set 7
PUC 7-1, 7-4, 7-7, and 7-8

PUC 9-19-1

Below is a list of towns with the number of planned AMF Meters to be deployed in FY 2025.

Deployment Sector	Town	Qtr-Year	Qty Residential	Qty Commercial	Total Qty Meters
Westerly	Westerly	Q4 2025	70	0	70
		Subtotal Westerly	**70**	**-**	**70**

PUC 9-19-2

Below is the portion of the planned AMF Network to be deployed in the town in FY 2025.

Deployment Sector	Town	Qtr-Year	Qty High Capacity Gateway	Qty Standard Capacity Gateway	Qty Router
Westerly	Westerly	Q2 2025	3	12	28
Westerly	Hopkinton	Q2 2025	0	15	56
Westerly	Richmond	Q3 2025	0	18	58
Westerly	Charlestown	Q3 2025	0	16	53
Westerly	South Kingstown	Q3 2025	1	22	62
Westerly	Narragansett	Q3 2025	2	8	4
		Total Westerly	**6**	**91**	**261**
Middletown	Jamestown	Q3 2025	0	7	15
Middletown	Newport	Q3 2025	6	1	8
Middletown	Middletown	Q4 2025	2	5	6
Middletown	Little Compton	Q4 2025	0	7	15
Middletown	Tiverton	Q4 2025	0	14	37
Middletown	Portsmouth	Q4 2025	0	15	28
		Total Middletown	**8**	**49**	**109**
North Kingstown-West	North Kingstown	Q4 2025	1	17	46
North Kingstown-West	Exeter	Q4 2025	0	14	83
North Kingstown-West	West Greenwich	Q4 2025	0	15	55
North Kingstown-West	Coventry	Q4 2025	2	15	97
North Kingstown-West	East Greenwich	Q4 2025	1	11	21
		Total North Kingstown-West	**4**	**72**	**302**

PUC 9-19-3

Below is a list of towns with the number of planned AMF Meters to be deployed in FY 2026.

Deployment Sector	Town	Qtr-Year	Qty Residential	Qty Commercial	Total Qty Meters
Westerly	Westerly	Q1 2026	13,906	796	14,702
Westerly	Hopkinton	Q1 2026	3,948	116	4,064
Westerly	Richmond	Q1 2026	3,602	99	3,701
Westerly	Charlestown	Q1 2026	5,947	97	6,044
Westerly	South Kingstown	Q1 2026	14,592	644	15,236
Westerly	Narragansett	Q1 2026	10,308	393	10,701
Total Westerly			**52,303**	**2,145**	**54,448**
Middletown	Jamestown	Q2 2026	3,695	81	3,776
Middletown	Newport	Q2 2026	15,636	776	16,412
Middletown	Middletown	Q2 2026	8,662	601	9,263
Middletown	Little Compton	Q2 2026	2,647	35	2,682
Middletown	Tiverton	Q2 2026	8,342	216	8,558
Middletown	Portsmouth	Q2 2026	10,110	320	10,430
Total Middletown			**49,092**	**2,029**	**51,121**
North Kingstown-West	North Kingstown	Q2 2026	13,647	818	14,465
North Kingstown-West	Exeter	Q2 2026	3,031	145	3,176
North Kingstown-West	West Greenwich	Q2 2026	2,892	131	3,022
North Kingstown-West	Coventry	Q2 2026	15,917	483	16,400
North Kingstown-West	East Greenwich	Q2 2026	6,079	423	6,502
Total North Kingstown - West			**41,566**	**2,000**	**43,565**
North Kingstown-East	West Warwick	Q2 2026	14,857	500	15,357
North Kingstown-East	Warwick	Q3 2026	39,293	2,521	41,814
Total North Kingstown - East			**54,150**	**3,021**	**57,171**
Providence-West	Cranston	Q3 2026	35,344	1,696	37,040
Providence-West	Johnston	Q3 2026	13,484	804	14,288
Total Providence-West			**48,828**	**2,500**	**51,328**

PUC 9-19-3 continued

Deployment Sector	Town	Qtr-Year	Qty Residential	Qty Commercial	Total Qty Meters
Providence-East	East Providence	Q3 2026	21,847	1,416	23,263
Providence-East	Barrington	Q3 2026	6,978	179	7,157
Providence-East	Warren	Q3 2026	6,087	268	6,355
Providence-East	Bristol	Q3 2026	10,116	614	10,730
		Total Providence-East	**45,028**	**2,477**	**47,505**
Providence	Providence	Q4 2026	75,697	4,100	79,797
		Total Providence	**75,697**	**4,100**	**79,797**
Chopmist	Foster	Q4 2026	2,160	20	2,180
Chopmist	Scituate	Q4 2026	4,893	77	4,970
Chopmist	Glocester	Q4 2026	4,911	75	4,985
Chopmist	Smithfield	Q4 2026	8,799	711	9,511
Chopmist/Lincoln East	North Providence*	Q4 2026	16,600	512	17,112
		Total Chopmist	**37,363**	**1,395**	**38,758**

*North Providence includes two Rhode Island Energy operating areas. AMF sectors are aligned with RIE operating areas.

PUC 9-19-4

Below is the portion of the planned AMF Network to be deployed in the town in FY 2026.

Deployment Sector	Town	Qtr-Year	Qty High Capacity Gateway	Qty Standard Capacity Gateway	Qty Router
North Kingstown-East	West Warwick	Q1 2026	5	4	11
North Kingstown-East	Warwick	Q1 2026	14	14	21
Total North Kingstown-East			**19**	**18**	**32**
Providence-West	Cranston	Q1 2026	9	14	25
Providence-West	Johnston	Q1 2026	4	13	38
Total Providence-West			**13**	**27**	**63**
Providence-East	East Providence	Q2 2026	7	5	13
Providence-East	Barrington	Q2 2026	1	3	4
Providence-East	Warren	Q2 2026	2	2	6
Providence-East	Bristol	Q2 2026	2	3	9
Total Providence-East			**12**	**13**	**32**
Providence	Providence	Q2 2026	25	7	19
Total Providence			**25**	**7**	**19**
Chopmist	Foster	Q2 2026	0	12	83
Chopmist	Scituate	Q2 2026	0	17	66
Chopmist	Glocester	Q2 2026	0	19	80
Chopmist	Smithfield	Q2 2026	0	12	36
Chopmist	North Providence*	Q2 2026	4	0	1
Total Chopmist			**4**	**60**	**266**
Lincoln-East	North Providence*	Q3 2026	1	2	0
Lincoln-East	Pawtucket	Q3 2026	10	1	9
Lincoln-East	Central Falls	Q3 2026	2	0	0
Lincoln-East	Lincoln	Q3 2026	1	14	39
Total Lincoln-East			**14**	**17**	**48**
Lincoln-West	Cumberland	Q3 2026	1	19	49
Lincoln-West	Woonsocket	Q3 2026	3	9	13
Lincoln-West	North Smithfield	Q3 2026	0	11	45
Lincoln-West	Burrillville	Q3 2026	0	9	41
Total Lincoln-West			**4**	**48**	**148**

*North Providence includes two Rhode Island Energy operating areas. AMF sectors are aligned with RIE operating areas.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Annual Revenue Requirement Summary - AMF Capital Investment

Line No.		Fiscal Year 4/1/24 - 3/31/25 2025 (a)
	AMF Incremental Capital Investment:	
1	Meters - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR	$1,924,241
2	Software - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR	$1,487,660
3	Network - Forecasted Revenue Requirement on FY 2025 Incremental Capital included in ISR	$310,771
4	Subtotal	$3,722,671
5	MDMS Software - Depreciation - No Return	$86,262
6	**Total AMF Capital Investment Component of Revenue Requirement**	**$3,808,934**
7	Deferrals to Offset AMF Capital Investment Revenue Requirement	(3,808,934)
8	**Net AMF Capital Investment Component of Revenue Requirement**	**$0**

Column/Line Notes:

1	Page 2, Line 23
2	Page 3, Line 23
3	Page 4, Line 23
4	Total Lines 1 through 3
5	Page 5, Line 23
6	Line 4 + Line 5
7	Page 10, Column AC, Line 5
8	Line 6 + Line 7

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Annual Revenue Requirement - AMF Capital Investment - Meters

		Source		Fiscal Year 2025
			(a)	(b)
1	370 - Meters	In-Service Plant		$ 31,010,789
2	Plant Capital Overheads	Input	0%	$0
3	Capital Spend - Annual	Line 1 + Line 2		$31,010,789
4	Capital Spend - Cumulative	PY Line 4 + CY Line 3		$31,010,789
5	370 - COR - Annual	Input		$0
6	Cumulative COR	Line 5		$0
7	Annual Federal Tax Depreciation	Page 6, Line 27		$3,101,079
8	Cumulative Federal Tax Depreciation	PY Line 8 + CY Line 7		$3,101,079
9	Annual Book Depreciation	Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a	4.49%	$695,882
10	Cumulative Book Depreciation	Line 9		$695,882
11	Accumulated Deferred Income Tax	(Line 10 - Line 8) x 21%	21%	$505,091
	Rate Base Calculation			
12	Plant In Service	Line 4		$31,010,789
13	Accumulated Reserve for Depreciation	- Line 10		($695,882)
14	Deferred Tax Reserve (ADIT)	- Line 11		($505,091)
15	Year End Rate Base	Sum of Lines 12 through 14		$29,809,816
	Revenue Requirement Calculation			
16	Average Rate Base	Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2		$14,904,908
17	Deferred Tax Proration Adjustment	Page 9, Column F, Line 41		$20,470
18	Average Rate Base adjusted	Line 16 + Line 17		$14,925,378
19	Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		8.23%
20	Return and Taxes	Line 18 x Line 19		$1,228,359
21	Book Depreciation	Line 9		$695,882
22	Property Taxes	RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.81%	$0
23	**Annual Revenue Requirement**	**Line 20 + 21 + 22**		**$1,924,241**

CY = Current Year
PY = Prior Year
Property Taxes - Zero for Year 1
Book Depreciation Rate - RIPUC Docket No. 4770

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Annual Revenue Requirement - AMF Capital Investment - Software (Excluding MDMS)

		Source		Fiscal Year 2025
			(a)	(b)
1	303 - Software	In-Service Plant		$ 13,662,927
2	Plant Capital Overheads	Input	0%	$0
3	Capital Spend - Annual	Line 1 + Line 2		$13,662,927
4	Capital Spend - Cumulative	PY Line 4 + CY Line 3		$13,662,927
5	303- COR - Annual	Input		$0
6	Cumulative COR	Line 5		$0
7	Annual Federal Tax Depreciation	Page 7, Line 27		$2,277,200
8	Cumulative Federal Tax Depreciation	PY Line 8 + CY Line 7		$2,277,200
9	Annual Book Depreciation	Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a	14.29%	$975,923
10	Cumulative Book Depreciation	Line 9		$975,923
11	Accumulated Deferred Income Tax	(Line 10 - Line 8) x 21%	21%	$273,268
	Rate Base Calculation			
12	Plant In Service	Line 4		$13,662,927
13	Accumulated Reserve for Depreciation	- Line 10		($975,923)
14	Deferred Tax Reserve (ADIT)	- Line 11		($273,268)
15	Year End Rate Base	Sum of Lines 12 through 14		$12,413,735
	Revenue Requirement Calculation			
16	Average Rate Base	Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2		$6,206,868
17	Deferred Tax Proration Adjustment	Page 9, Column G, Line 41		$11,075
18	Average Rate Base adjusted	Line 16 + Line 17		$6,217,943
19	Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		8.23%
20	Return and Taxes	Line 18 x Line 19		$511,737
21	Book Depreciation	Line 9		$975,923
22	Property Taxes	RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.81%	$0
23	**Annual Revenue Requirement**	**Line 20 + 21 + 22**		**$1,487,660**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Annual Revenue Requirement - AMF Capital Investment - Network

		Source		Fiscal Year 2025
			(a)	(b)
1	397 - Network	In-Service Plant		$ 4,841,796
2	Plant Capital Overheads	Input	0%	$0
3	Capital Spend - Annual	Line 1 + Line 2		$4,841,796
4	Capital Spend - Cumulative	PY Line 4 + CY Line 3		$4,841,796
5	397 - COR - Annual	Input		$0
6	Cumulative COR	Line 5		$0
7	Annual Federal Tax Depreciation	Page 8, Line 27		$691,893
8	Cumulative Federal Tax Depreciation	PY Line 8 + CY Line 7		$691,893
9	Annual Book Depreciation	Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a	5.00%	$121,045
10	Cumulative Book Depreciation	Line 9		$121,045
11	Accumulated Deferred Income Tax	(Line 10 - Line 8) x 21%	21%	$119,878
	Rate Base Calculation			
12	Plant In Service	Line 4		$4,841,796
13	Accumulated Reserve for Depreciation	- Line 10		($121,045)
14	Deferred Tax Reserve (ADIT)	- Line 11		($119,878)
15	Year End Rate Base	Sum of Lines 12 through 14		$4,600,873
	Revenue Requirement Calculation			
16	Average Rate Base	Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2		$2,300,436
17	Deferred Tax Proration Adjustment	Page 9, Column H, Line 41		$4,858
18	Average Rate Base adjusted	Line 16 + Line 17		$2,305,295
19	Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		8.23%
20	Return and Taxes	Line 18 x Line 19		$189,726
21	Book Depreciation	Line 9		$121,045
22	Property Taxes	RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.81%	$0
23	**Annual Revenue Requirement**	**Line 20 + 21 + 22**		**$310,771**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Annual Revenue Requirement - AMF Capital Investment - MDMS

		Source		Fiscal Year 2025
			(a)	(b)
1	303 - Software	In-Service Plant		$ 1,207,674
2	Plant Capital Overheads	Input	0%	$0
3	Capital Spend - Annual	Line 1 + Line 2		$1,207,674
4	Capital Spend - Cumulative	PY Line 4 + CY Line 3		$1,207,674
5	303- COR - Annual	Input		$0
6	Cumulative COR	Line 5		$0
7	Annual Federal Tax Depreciation	N/A		$0
8	Cumulative Federal Tax Depreciation	PY Line 8 + CY Line 7		$0
9	Annual Book Depreciation	Year 1 = Line 4 * Line 9, column a * 50%; Then = Line 4 * Line Line 9, column a	14.29%	$86,262
10	Cumulative Book Depreciation	Line 9		$86,262
11	Accumulated Deferred Income Tax	(Line 10 - Line 8) x 21%	21%	$0
	Rate Base Calculation			
12	Plant In Service	Line 4		$0
13	Accumulated Reserve for Depreciation	- Line 10		$0
14	Deferred Tax Reserve (ADIT)	- Line 11		$0
15	Year End Rate Base	Sum of Lines 12 through 14		$0
	Revenue Requirement Calculation			
16	Average Rate Base	Year 1 = CY, Line 15 * 50%; Then = PY Line 15 + CY Line 15 / 2		$0
17	Deferred Tax Proration Adjustment			$0
18	Average Rate Base adjusted	Line 16 + Line 17		$0
19	Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		0.00%
20	Return and Taxes	Line 18 x Line 19		$0
21	Book Depreciation	Line 9		$86,262
22	Property Taxes	RIPUC Docket No. 5209 FY 2023 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.81%	$0
23	**Annual Revenue Requirement**	**Line 20 + 21 + 22**		**$86,262**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Meters

Line No.				Fiscal Year 2025 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2, Line 4		$31,010,789
2	Capital Repairs Deduction Rate	Per Tax Department	1/	0.00%
3	Capital Repairs Deduction	Line 1 * Line 2		$0
4				
5	Bonus Depreciation			
6	Plant Additions	Line 1		$31,010,789
7	Plant Additions			$0
8	Less Capital Repairs Deduction	Line 3		$0
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$31,010,789
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0
12	Bonus Depreciation Rate	at 0%		0.00%
13	Total Bonus Depreciation Rate	Line 12		0.00%
14	Bonus Depreciation	Line 11 * Line 13		$0
15				
16	Remaining Tax Depreciation			
17	Plant Additions	Line 1		$31,010,789
18	Less Capital Repairs Deduction	Line 3		$0
19	Less Bonus Depreciation	Line 14		$0
20	Remaining Plant Additions Subject to 10 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$31,010,789
21	10 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		10.000%
22	Remaining Tax Depreciation	Line 20 * Line 21		$3,101,079
23				
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0
25	Cost of Removal			$0
26				
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$3,101,079

10 Year MACRS Depreciation

(b)	(c)	(d)	(e)
MACRS basis:	Line 20	$31,010,789	
		Annual	Cumulative
Fiscal Year			
March 2025	10.000%	$3,101,079	$3,101,079
March 2026	18.000%	$5,581,942	$8,683,021
March 2027	14.400%	$4,465,554	$13,148,575
March 2028	11.520%	$3,572,443	$16,721,018
March 2029	9.220%	$2,859,195	$19,580,212
March 2030	7.370%	$2,285,495	$21,865,708
March 2031	6.550%	$2,031,207	$23,896,914
March 2032	6.550%	$2,031,207	$25,928,121
March 2033	6.560%	$2,034,308	$27,962,429
March 2034	6.550%	$2,031,207	$29,993,635
March 2035	3.280%	$1,017,154	$31,010,789
	100.00%	$31,010,789	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Software

Line No.				Fiscal Year 2025 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 4, Line 4		$13,662,927	3 Year MACRS Depreciation Straight Line			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	0.00%				
3	Capital Repairs Deduction	Line 1 * Line 2		$0	MACRS basis:	Line 20	$13,662,927	
4							Annual	Cumulative
5	Bonus Depreciation				Fiscal Year			
6	Plant Additions	Line 1		$13,662,927	March 2025	16.667%	$2,277,200	$2,277,200
7	Plant Additions			$0	March 2026	33.333%	$4,554,263	$6,831,463
8	Less Capital Repairs Deduction	Line 3		$0	March 2027	33.333%	$4,554,263	$11,385,727
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$13,662,927	March 2028	16.667%	$2,277,200	$13,662,927
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%				
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0		100.00%	$13,662,927	
12	Bonus Depreciation Rate	at 0%		0.00%				
13	Total Bonus Depreciation Rate	Line 12		0.00%				
14	Bonus Depreciation	Line 11 * Line 13		$0				
15								
16	Remaining Tax Depreciation							
17	Plant Additions	Line 1		$13,662,927				
18	Less Capital Repairs Deduction	Line 3		$0				
19	Less Bonus Depreciation	Line 14		$0				
20	Remaining Plant Additions Subject to 3 YR MACRS Tax Depreciation Straight Line	Line 17 - Line 18 - Line 19		$13,662,927				
21	3 YR MACRS Tax Depreciation Rates Straight Line	Per IRS Publication 946		16.667%				
22	Remaining Tax Depreciation	Line 20 * Line 21		$2,277,200				
23								
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0				
25	Cost of Removal			$0				
26								
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$2,277,200				

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Calculation of Tax Depreciation and Repairs Deduction on FY 2025 Network

Line No.				Fiscal Year 2025 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 4, Line 4		$4,841,796	7 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	0.00%				
3	Capital Repairs Deduction	Line 1 * Line 2		$0	MACRS basis:	Line 20	$4,841,796	
4							Annual	Cumulative
5	Bonus Depreciation				Fiscal Year			
6	Plant Additions	Line 1		$4,841,796	March 2025	14.290%	$691,893	$691,893
7	Plant Additions			$0	March 2026	24.490%	$1,185,756	$1,877,649
8	Less Capital Repairs Deduction	Line 3		$0	March 2027	17.490%	$846,830	$2,724,479
9	Plant Additions Net of Capital Repairs Deduction	Line 6 + Line 7 - Line 8		$4,841,796	March 2028	12.490%	$604,740	$3,329,219
10	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	March 2029	8.930%	$432,372	$3,761,591
11	Plant Eligible for Bonus Depreciation	Line 9 * Line 10		$0	March 2030	8.920%	$431,888	$4,193,480
12	Bonus Depreciation Rate	at 0%		0.00%	March 2031	8.930%	$432,372	$4,625,852
13	Total Bonus Depreciation Rate	Line 12		0.00%	March 2032	4.460%	$215,944	$4,841,796
14	Bonus Depreciation	Line 11 * Line 13		$0		100.00%	$4,841,796	
15								
16	Remaining Tax Depreciation							
17	Plant Additions	Line 1		$4,841,796				
18	Less Capital Repairs Deduction	Line 3		$0				
19	Less Bonus Depreciation	Line 14		$0				
20	Remaining Plant Additions Subject to 7 YR MACRS Tax Depreciation	Line 17 - Line 18 - Line 19		$4,841,796				
21	7 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		14.290%				
22	Remaining Tax Depreciation	Line 20 * Line 21		$691,893				
23								
24	FY25 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$0				
25	Cost of Removal			$0				
26								
27	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 22, 24, and 25		$691,893				

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Calculation of Net Deferred Tax Reserve Proration on FY 2025 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration			Meters FY 2025 (a)	Software FY 2025 (b)	Network FY 2025 (c)
1	Book Depreciation	Page 2, 3, 4; Line 9		$695,882	$975,923	$121,045
2	Bonus Depreciation	Page 5,6, 7; Line 14		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Page 5,6, 7; Line 22		($3,101,079)	($2,277,200)	($691,893)
4	FY 2025 tax (gain)/loss on retirements	Page 5,6, 7; Line 24		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($2,405,197)	($1,301,277)	($570,848)
6	Effective Tax Rate			21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($505,091)	($273,268)	($119,878)
	Deferred Tax Not Subject to Proration					
8	Capital Repairs Deduction	Page 5,6, 7; Line 3		$0	$0	$0
9	Cost of Removal	Page 5,6, 7; Line 25		$0	$0	$0
10	Book/Tax Depreciation Timing Difference at 3/31/2025					
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		$0	$0	$0
12	Effective Tax Rate			21.00%	21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12		$0	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13		($505,091)	($273,268)	($119,878)
15	Net Operating Loss			$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($505,091)	($273,268)	($119,878)
	Allocation of FY 2024 Estimated Federal NOL					
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		($2,405,197)	($1,301,277)	($570,848)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($2,405,197)	($1,301,277)	($570,848)
20	Total FY 2025 Federal NOL (Utilization)			$0	$0	$0
21	Allocated FY 2025 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		$0	$0	$0
22	Allocated FY 2025 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		$0	$0	$0
23	Effective Tax Rate			21%	21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		$0	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($505,091)	($273,268)	($119,878)
		(d)	(e)	(f)	(g)	(h)
	Proration Calculation	Number of Days in Month	Proration Percentage			
26	January	31	91.53%	($38,526)	($20,844)	($9,144)
27	February	29	83.61%	($35,191)	($19,039)	($8,352)
28	March	31	75.14%	($31,626)	($17,110)	($7,506)
29	April	30	66.94%	($28,176)	($15,244)	($6,687)
30	May	31	58.47%	($24,611)	($13,315)	($5,841)
31	June	30	50.27%	($21,160)	($11,448)	($5,022)
32	July	31	41.80%	($17,595)	($9,520)	($4,176)
33	August	31	33.33%	($14,030)	($7,591)	($3,330)
34	September	30	25.14%	($10,580)	($5,724)	($2,511)
35	October	31	16.67%	($7,015)	($3,795)	($1,665)
36	November	30	8.47%	($3,565)	($1,929)	($846)
37	December	31	0.00%	$0	$0	$0
38	Total	366		($232,075)	($125,559)	($55,081)
39	Deferred Tax Without Proration	Line 25		($505,091)	($273,268)	($119,878)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($252,546)	($136,634)	($59,939)
41	Proration Adjustment	Line 38 - Line 40		$20,470	$11,075	$4,858

Column Notes:
(e) Sum of remaining days in the year (Col (d)) ÷ 365
(f), (g), (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan - AMF
Deferral Balances

Line No.		Rate Year Ending August 31, 2019			Rate Year Ending August 31, 2020			Rate Year Ending August 31, 2021			Rate Year Ending August 31, 2022			Rate Year Ending August 31, 2023			August 31, 2023
		Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Cumulative Deferral
		(a)	(b)	(c)=(a)-(b)	(d)	(e)	(f)=(d)-(e)	(g)	(h)	(i)=(g)-(h)	(j)	(k)	(l)=(j)-(k)	(m)	(n)	(o)=(m)-(n)	(p) = (c)+(f)+(i)+(l)+=(o)
1	AMI Business Case Study	$2,000,000	$666,667	$1,333,333	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	($1,333,333)
2	GIS Enhancements (IS	$11,119	$142,333	($131,214)	$20,451	$142,333	($121,883)	$8,739	$142,333	($133,595)	$115,356	$142,333	($26,978)	$0	$142,333	($142,333)	($556,002)
3	Special Sector: Storage	$0	$112,586	($112,586)	$5,464	$259,668	($254,204)	$5,564	$411,986	($406,422)	$0	$411,986	($411,986)	$0	$411,986	($411,986)	($1,597,184)
4	Special Sector: Electric Transportation	$312,370	$681,300	($368,930)	$1,106,790	$1,151,751	($44,961)	$1,023,537	$2,151,776	($1,128,239)	$1,419,934	$2,151,776	($731,842)	$1,252,963	$2,151,776	($898,813)	($3,172,785)
				$0			$0			$0			$0			$0	
5	**Total**	**$2,323,489**	**$1,602,886**	**$720,603**	**$1,132,705**	**$2,220,419**	**($1,087,714)**	**$1,037,839**	**$3,372,762**	**($2,334,923)**	**$1,535,290**	**$3,372,762**	**($1,837,472)**	**$1,252,963**	**$3,372,762**	**($2,119,799)**	**($6,659,305)**
6	AMF Related Grid Mod in Base Rates		$325,733	($325,733)		$946,878	($946,878)		$1,234,459	($1,234,459)		$1,234,459	($1,234,459)		$1,234,459	($1,234,459)	($4,975,988)

Line No.		Forecasted Rate Year Ending August 31, 2024			Forecasted Rate Year Ending August 31, 2025			Forecasted Rate Year Ending August 31, 2026			Forecasted Cumulative Defereral August 31, 2026			Deferral Balance Used for AMF Capital Revenue Requirement FY 2025	Forecasted Remaining Deferral As of 8/31/26
		Forecasted Spend	Rate Allowance	Deferral	Forecasted Spend	Rate Allowance	Deferral	Forecasted Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral		
		(q)	(r)	(s)=(q)-(r)	(t)	(u)	(v)=(t)-(u)	(w)	(x)	(y)=(w)-(x)	(z)	(aa)	(ab)=(p)+(s)+(v)+(y)	(ac)	(ad)
1	AMI Business Case Study	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($3,333,333)	$0	($3,333,333)
2	GIS Enhancements (IS	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$115,356	$142,333	($983,002)	$0	($983,002)
3	Special Sector: Storage	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$0	$411,986	($2,833,142)	$2,833,142	$0
4	Special Sector: Electric Transportation	$936,940	$2,151,776	($1,214,836)	$776,940	$2,151,776	($1,374,836)	$755,940	$2,151,776	($1,395,836)	$1,419,934	$2,151,776	($7,158,293)	$975,791	($6,182,502)
				$0			$0			$0			$0	$0	$0
5	**Total**	**$936,940**	**$3,372,762**	**($2,435,822)**	**$776,940**	**$3,372,762**	**($2,595,822)**	**$755,940**	**$3,372,762**	**($2,616,822)**	**$1,535,290**	**$3,372,762**	**($14,307,771)**	**$3,808,934**	($10,498,838)
6	AMF Related Grid Mod in Base Rates	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($8,679,365)	$0	($8,679,365)

Line Notes:
1b, 1e, 1h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 26
2b, 2e, 2h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 27
3b, 3e, 3h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 36
4b, 4e, 4h Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 33
4p Docket No. 4770, Electric Transportation Rate Year 5 Annual Report, Table 4, Column E
Columns k, n, r, u, x - Rate Allowance from Rate Year August 2021 continued until next base distribution rate case

Columns a, d, g, j, m - actual revenue requirement on actual spend
Columns q, t, w - forecasted revenue requirement on forecasted spend

PUC 9-20
Meters (AMF/AMR)

Request:

For each town included in the tables provided in Attachments to PUC 5-9, please provide a table with columns for:

a. The planned spending on AMF meters for that town in FY25,
b. The amount of part a used to set the FY25 revenue requirement,
c. The planned spending on AMF network for that town in FY25,
d. The amount of part c used to set the FY25 revenue requirement, and
e. Four additional columns with the same information but replacing "FY25" with "FY26." (Please note, part e is *not* seeking what portion of FY25 spending will be included in FY26 rates.)

Response:

Through and including this response, Rhode Island Energy is addressing updates to the Advanced Metering Functionality ("AMF") implementation schedule.

The primary reason for the AMF updates, which are included in this response, is the schedule shift of the final Transition Services Agreement ("TSA") exit date from National Grid USA's systems to PPL's systems moving from May 2024 to August 2024. The shift of the TSA exit date results in a shift of AMF timing and approach. Along with a needed update in the systems functionality release approach and schedule, meter deployment start will move from January 2025 to March 2025. There is no change to the timing of pre-sweeps and network deployment.

The secondary reason for the AMF updates is a result of finalizing or near finalization of vendor contracts, resulting in firm cost estimates. There is no change to the overall AMF program cost but the update does reduce FY2025 forecasted spend and increases FY2026 and FY2027.

a. The following are added notes to the chart below:

- Due to timing and maintaining schedule for meter installation deployment, there will be meter and antenna delivery spend, and meter testing spend, in FY2025 that is for meter installations in FY2026. These are captured in stand-alone line items in the chart below.

- Meter installation milestone achievement, which is at the sector level, is paid out upon sector acceptance. In FY2025, no meter installation milestones will be achieved. The spend captured for the town of Westerly encompasses the meter hardware cost of the 70 planned AMF meters to be installed.

PUC 9-20, page 2

Meters (AMF/AMR)

- Deployment planning milestones, which covers the completion of all necessary deployment planning activities to begin pre-sweeps, network, and meter deployment, are planned to be achieved in FY2025.

- Pre-sweep completion milestones, for specific sectors and towns, are planned to be achieved in FY2025 but meter installations will not be completed in FY2025.

Deployment Sector	Town	Qtr-Year	Spend
Westerly	Westerly	Q4 2025	$8,636
		Subtotal Westerly	**$8,636**
Meter deliveries FY25 for FY26 meter installations			$24,860,235
Meter installation vendor planning milestones achievement			$1,644,725
Pre-sweep milestones achievement			$2,168,648
Meter antenna purchases in FY25 for FY26 meter installations			$29,853
Sample meter testing FY25 for meter deliveries			$12,490
		Total	**$28,724,587**

b. The full amount of part a.) FY2025 spend is used to set the FY2025 revenue requirement.

c. The following are added notes to the chart below:

- Due to timing and maintaining schedule for network deployment, there will be network equipment delivery spend in FY2025 that is for network installations in FY2026. This is captured in the stand-alone line item in the chart below.

PUC 9-20, page 3

Meters (AMF/AMR)

Deployment Sector	Town	Qtr-Year	Spend
Westerly	Westerly	Q2 2025	$173,152
Westerly	Hopkinton	Q2 2025	$241,978
Westerly	Richmond	Q3 2025	$237,951
Westerly	Charlestown	Q3 2025	$226,841
Westerly	South Kingstown	Q3 2025	$283,057
Westerly	Narragansett	Q3 2025	$79,109
Middletown	Jamestown	Q3 2025	$83,325
Middletown	Newport	Q3 2025	$113,454
Middletown	Middletown	Q4 2025	$65,665
Middletown	Little Compton	Q4 2025	$71,935
Middletown	Tiverton	Q4 2025	$174,346
Middletown	Portsmouth	Q4 2025	$154,239
North Kingstown-West	North Kingstown	Q4 2025	$257,030
North Kingstown-West	Exeter	Q4 2025	$288,386
North Kingstown-West	West Greenwich	Q4 2025	$216,471
North Kingstown-West	Coventry	Q4 2025	$375,314
North Kingstown-West	East Greenwich	Q4 2025	$116,701
		Sub-Total	**$3,158,953**
Network equipment deliveries FY25 for FY26 network installations			$1,319,953
		Total	**$4,478,906**

d. The full amount of part c.) FY2025 spend is used to set the FY2025 revenue requirement.

e. This response replaces FY2025 with FY2026 following the same approach as outlined in responses a.) and c.). The first chart represents AMF meter spend for FY2026 and the second chart covers AMF network spend for FY2026. As with responses, b.) and d.), the full amount of FY2026 spend is used to set the FY2026 revenue requirements.

PUC 9-20, page 4

Meters (AMF/AMR)

Deployment Sector	Town	Qtr-Year	Total Town Cost
Westerly	Westerly	Q1 2026	$2,422,338
Westerly	Hopkinton	Q1 2026	$658,492
Westerly	Richmond	Q1 2026	$598,999
Westerly	Charlestown	Q1 2026	$971,629
Westerly	South Kingstown	Q1 2026	$2,489,969
Westerly	Narragansett	Q1 2026	$1,742,795
Middletown	Jamestown	Q2 2026	$609,102
Middletown	Newport	Q2 2026	$2,690,530
Middletown	Middletown	Q2 2026	$1,535,131
Middletown	Little Compton	Q2 2026	$430,338
Middletown	Tiverton	Q2 2026	$1,383,780
Middletown	Portsmouth	Q2 2026	$1,692,245
North Kingstown-West	North Kingstown	Q2 2026	$2,384,984
North Kingstown-West	Exeter	Q2 2026	$520,137
North Kingstown-West	West Greenwich	Q2 2026	$494,331
North Kingstown-West	Coventry	Q2 2026	$2,658,813
North Kingstown-West	East Greenwich	Q2 2026	$1,077,674
North Kingstown-East	West Warwick	Q2 2026	$2,494,574
North Kingstown-East	Warwick	Q3 2026	$6,910,187
Providence-West	Cranston	Q3 2026	$6,066,588
Providence-West	Johnston	Q3 2026	$2,355,394
Providence-East	East Providence	Q3 2026	$3,845,815
Providence-East	Barrington	Q3 2026	$1,157,079
Providence-East	Warren	Q3 2026	$1,038,514
Providence-East	Bristol	Q3 2026	$1,769,892
Providence	Providence	Q4 2026	$13,114,929
Chopmist	Foster	Q4 2026	$348,931
Chopmist	Scituate	Q4 2026	$798,693
Chopmist	Glocester	Q4 2026	$801,035
Chopmist	Smithfield	Q4 2026	$1,585,626
Chopmist/Lincoln East	North Providence*	Q4 2026	$2,775,062
		Town Subtotal:	**$69,423,607**

Meter deliveries FY25 that are installed in FY26	($24,860,235)
Meter deliveries FY26 for FY27 meter installations	$13,839,944
Pre-sweep milestones achievement	$3,339,661
Meter antenna purchases in FY26 for FY27 meter installations	$29,853
Sample meter testing FY26 for meter deliveries	$21,720
Total	**$61,794,551**

Prepared by or under the supervision of: Philip Walnock and Parker Capwell

PUC 9-20, page 5

Meters (AMF/AMR)

Deployment Sector	Town	Qtr-Year	Town Totals
North Kingstown-E	West Warwick	Q1 2026	$188,091
North Kingstown E	Warwick	Q1 2026	$442,512
		Total North Kingstown-East	
Providence W	Cranston	Q1 2026	$374,043
Providence W	Johnston	Q1 2026	$383,167
		Total Providence-West	
Providence E	East Providence	Q2 2026	$220,528
Providence E	Barrington	Q2 2026	$63,400
Providence E	Warren	Q2 2026	$80,774
Providence E	Bristol	Q2 2026	$104,752
		Total Providence-East	
Providence Central	Providence	Q2 2026	$529,104
		Total Providence	
Chopmist	Foster	Q2 2026	$549,407
Chopmist	Scituate	Q2 2026	$513,908
Chopmist	Glocester	Q2 2026	$583,624
Chopmist	Smithfield	Q2 2026	$321,898
Chopmist	North Providence*	Q2 2026	$65,415
		Total Chopmist	
Lincoln E	North Providence*	Q3 2026	$28,062
Lincoln E	Pawtucket	Q3 2026	$209,897
Lincoln E	Central Falls	Q3 2026	$38,613
Lincoln E	Lincoln	Q3 2026	$343,882
		Total Lincoln-East	
Lincoln W	Cumberland	Q3 2026	$458,711
Lincoln W	Woonsocket	Q3 2026	$178,389
Lincoln W	North Smithfield	Q3 2026	$341,952
Lincoln W	Burrillville	Q3 2026	$293,742
		Total Lincoln-West	
		Subtotals	**$6,313,869**
		Network equipment deliveries FY25 that are installed in FY26	($1,319,953)
		Network equipment deliveries FY26 for FY27 network installations	$0
		1 time Wi-SUN capability licenses	$3,379,640
		Total	**$8,373,556**

Prepared by or under the supervision of: Philip Walnock and Parker Capwell

Meters (AMF/AMR)

The information reflected above is represented in ISR fiscal quarters.

Additionally, please see Attachment PUC 9-19-5, which is an updated Section 5, Attachment 3, which was originally filed as part of the Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan Filing (starting on Bates 277). The revised revenue requirement reflects the updated forecasted FY 2025 capital in service for the reasons described above, as well as reflecting 1) the corrected book depreciation rate for network investments as described in the response to PUC 2-3 and 2) the removal of MDMS costs from software rather than meters as was described in the response to PUC 4-5. On the attachment, the Company has highlighted the cells that have input changes from the originally filed revenue requirement. The Company did not highlight all of the flow through cells that changed.

Prepared by or under the supervision of: Philip Walnock and Parker Capwell

PUC 9-21
Blankets

Request:

The response to PUC 5-8 shows forecasted spending on Discretionary Blankets in FY 2024 will be approximately $3.6 million over budget.

a. Please explain why the Reliability Blanket is projected to be over budget by approximately $1.6 million, including a description of the types of projects that will cause the overspend;

b. Please explain why the Load Relief Blanket is projected to be over budget by approximately $1.6 million, including a description of the types of projects that will cause the overspend; and

c. Please explain why the Load Relief Blanket is projected to be over budget by approximately $466,000, including a description of the types of projects that will cause the overspend.

Response:

a. The Reliability Blanket project is forecasted to be over budget because of additional work done to improve reliability and capacity and minimize outage exposure. The Company has many projects that can fall within this discretionary reliability blanket. The Company continuously reviews these projects and makes decisions to advance those that pose the highest risk. The work advanced this year was prioritized because the Company believes that delaying it may have potential impact to safety and reliability.

   As of January 31, 2024, approximately 130 work orders have received capital charges. The capital charges in this Blanket range from hundreds of dollars to as high as five hundred thousand dollars (specific project threshold).

   Projects less than $100,000 account for approximately 38% of the Reliability Blanket's capital charges. These projects typically include, but are not limited to, the installation of fault indicators, which make fault locating easier for line crews, replacement of fuses with cutout mounted reclosers to reduce the impact of temporary faults, addressing construction that may be prone to more outages like limited reconductoring of bare to covered wire, removing osprey nests that expose circuits to outages, and replacing live front equipment with standard insulated connections.

PUC 9-21, page 2
Blankets

Upon review, the Company has identified that the replacement of poles most likely due to asset condition and approximately $75,000 in projects addressing capacitor and regulator replacements and installations that most likely were needed to address emerging voltage issues.

Projects greater than $100,000 account for 62% of the Reliability Blanket's capital charges. These projects mainly address emerging issues that were exposing customers to long outages. These projects included relocating and replacing underground equipment with operating issues, addressing live front underground equipment with operation issues, removing common mode failure of two circuits that were alternate supplies to each other, and addressing aged poles in a wetland serving Prudence Island.

An additional four work orders are under review for appropriateness of charges and project classification. The first involves the conversion of a step-down area with an overloaded transformer, with approximately $300,000 of capital charges. The second currently appears to be an error associated with the work management system automatically submitting material requisitions for approximately $170,000 during transition to the new software. The last two are conversion projects of 4kV, with approximately $375,000 of capital charges, which the Company expects should fall under the Providence Area Study work.

b. The Load Relief Blanket projects are forecasted to be over budget because of additional work resulting from annual contingency planning, a small area study project, and other work done to avoid overloads and minimize outage exposure. Although this spending is categorized as discretionary, this work was prioritized because the Company believes that delaying it may have potential impact to safety and reliability.

As of January 2024, approximately 70 work orders have received capital charges. The capital charges in this Blanket range from hundreds of dollars to as high as $160,000.

There is a project in this Blanket, with Capital charges of approximately $810,000, which was misclassified as blanket project work. This project should be included as a specific System Capacity project that was advanced to avoid a potential overload identified in the Company's annual planning exercise.

Projects less than $100,000 account for approximately 75% of the Load Relief Blanket's capital charges. These projects typically include, but are not limited to, load transfers,

PUC 9-21, page 3
Blankets

minor reconductoring, and equipment upgrades to address overloading issues identified during annual planning reviews. Upon review, the Company has identified approximately $65,000 in projects addressing overloaded transformers that likely were identified due to voltage complaints.

Projects greater than $100,000 account for 25% of the Load Relief Blanket's capital charges. These projects mainly addressed emerging overload issues identified during the Company's annual planning review through circuit reconfigurations and load transfers.

c. The Company assumes that part c of this request refers to the Asset Replacement Blanket. The Blanket is forecasted to be over budget primarily because of additional asset replacement work associated with underground faults and follow up work after assets failed. Although this spending is categorized as discretionary, this work was prioritized because the Company believes that delaying it may have potential impact to safety and reliability.

As of January 31, 2024, approximately 400 work orders have received capital charges. The capital charges in this Blanket range from hundreds of dollars to as high as a couple hundred thousand dollars.

Projects less than $100,000 account for approximately 80% of the Asset Replacement Blanket's capital charges. These projects typically include, but are not limited to, monthly confirming work orders for very small dollar work, replacement of rotted equipment such as poles and cross arms, replacement of open wire secondary that is uninsulated conductor requiring additional clearances on the pole greater than standard secondary, and adjacent underground secondary cable that has been exposed to high fault currents making it more susceptible to failure.

Projects greater than $100,000 account for 20% of the Asset Condition Blanket's capital charges. This review identified an overloaded transformer project with capital charges of approximately $225,000 that the Company currently expects should be moved to the OLT program. One project involved the replacement of live front equipment that needed to be removed to address a cable termination failure to reenergize an elderly housing building. A portion of this work was charged to Damage/Failure, but the replacement of the live front switch gear with standard insulated equipment was addressed under this Blanket.

PUC 9-21, page 4

Blankets

Further review of the projects in this Blanket suggests that approximately $200,000 of capital charges appear to be damage failure.

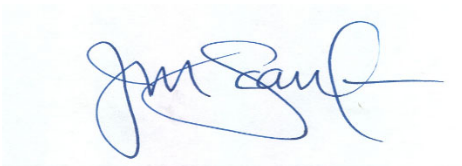
Although these Blankets are forecasted to be over budget, the Company continues to manage the overall discretionary portfolio so that spend, as appropriate, meets pre-approved levels. Discretion is given to Engineering teams to classify the work as they are creating projects, and managers are not overseeing this on a work order basis. Because most work ultimately impacts reliability, this is often selected as the budget classification. The Company continues to prioritize work appropriately, and currently the FY 2024 forecast for Discretionary projects, programs, and blankets capital spending, excluding separately tracked large projects, is under the approved budget of $42 million.

Prepared by or under the supervision of: Kathy Castro

Certificate of Service

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

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



Joanne M. Scanlon

March 5, 2024
Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
Service List as of 1/25/2024

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