COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation	)	D.P.U. 20-75

NATIONAL GRID SYSTEM PLANNING ANALYSIS PROPOSAL

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("National Grid" or the "Company") offers this system planning analysis proposal to the Department of Public Utilities (the "Department") in response to the Department's March 23, 2021 Procedural Notice, Request for Comments, and Information Requests ("H.O. Memorandum") requesting that the electric distribution companies develop system planning analysis proposals to implement the distribution system assessment process.[1]

I. INTRODUCTION AND PROCEDURAL HISTORY

Pursuant to its ratemaking authority under G.L. c. 164, § 94 and its superintendence authority under G.L. c. 164, § 76, on October 22, 2020 the Department issued an order ("Order") opening an investigation into two issues for the electric distribution companies[2] (individually "EDC" and collectively "EDCs"): (1) distributed energy resource ("DER") planning and (2) the

[1] Capitalized terms that are not defined in this prposal are defined in the Order, the Straw Proposal or the Standards for Interconnection of Distributed Generation, M.D.P.U. No. 1320.

[2] National Grid, NSTAR Electric Company d/b/a Eversource Energy ("Eversource") and Fitchburg Gas and Electric Light Company d/b/a Unitil.

associated assignment and recovery of costs related to the distributed generation ("DG")[3] process and infrastructure modifications needed to interconnect DG to an EDC's electric power system ("EPS").

Through this Order, the Department proposes a new DER[4] planning process with the purpose of assessing optimal solutions for the interconnection of DG facilities, taking a long-term planning perspective. Also, the Department seeks comment on methods for the assignment and recovery of costs associated with the DG interconnection process and system modifications needed for interconnection. These proposals and requests for comment were presented as a Straw Proposal set forth in Attachment A to the Order ("Straw Proposal"). On December 23, 2020 the Company and the other EDCs filed initial comments in response to the Straw Proposal, as did other commenters,[5] and on February 5, 2021 the Company and the other EDCs, as well as other commenters, filed reply comments. The Company's initial comments are referred to herein as "Initial Comments" and the Company's reply comments are referred to as "Reply Comments." The Company and the other EDCs responded to the Department's Information Requests to the EDCs in the H.O. Memorandum on April 6, 2021 and other commenters responded to the Department's Information Requests to stakeholders on April 13, 2021.

National Grid strongly supports the Department establishing a long-term DER system planning program, as discussed in more detail in the Company's Initial Comments and Reply Comments. In developing its system planning analysis proposal for such a long-term DER

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3 For the purposes of the Order and the Straw Proposal, the term DG refers to any type of Facility that must submit an application under an EDC's DG Interconnection Tariff, regardless of whether the Facility actually generates electricity (e.g., energy storage systems). Order at 1, footnote 3.

4 For the purposes of the Order and the Straw Proposal, the term DER includes distributed generation (e.g., solar panels), energy storage systems, electric vehicles, and controllable loads (e.g., heating, ventilation, and air conditioning systems and electric water heaters). Att. A at 3, footnote 1.

5 Several commenters filed initial comments on December 17, 2020 and one commenter filed initial comments on December 10, 2020.

planning process ("Planning Analysis"), the Company has expanded on the planning process described in its Reply Comments, taking into consideration other commenters' initial and reply comments.

In accordance with the H.O. Memorandum, the Company's Planning Analysis includes the following criteria:

i. Defined scope of analysis;

ii. Analysis for distribution and transmission level upgrades;

iii. Procedural steps the Company is taking or will take internally to implement the proposal;

iv. How the analysis will consider the Commonwealth's clean energy and climate policy objectives, including climate change mitigation, adaptation, and resilience;

v. Stakeholder participation; and

vi. Timeline for implementation.

As a baseline for its annual rolling 10-year assessment of its distribution system, the Company will identify system upgrades to accommodate forecasted load growth and DG Facility interconnection. The assessment will identify multi-value upgrades that provide solutions to traditional electric power system ("EPS") constraints (e.g., load relief, reliability, asset condition) and also enable the interconnection of additional capacity beyond currently proposed DG Facilities. The Company will engage external stakeholders to help inform the Company's development of future DER scenarios and feeder-level load forecasts that will be used to identify the need for future system upgrades. (H.O. Memorandum at 2-4)

II. DEFINED SCOPE OF ANALYSIS

The Planning Analysis will identify distribution system infrastructure investments and supporting transmission system infrastructure investments ("T&D") needed to meet the Commonwealth's climate and clean energy policy objectives and, in particular, to enable interconnection of currently proposed and future Facilities.[6] The Planning Analysis will proceed in four stages, as described in more detail in below: Stage 1 – Load and DER Growth Forecasting; Stage 2 – EPS Impact Analysis; Stage 3 – Area Planning Study Process; Stage 4 – Capital Improvement Project ("CIP") Proposals. For comparison, in National Grid's Reply Comments at 8, the Company provided a diagram that overlay an "Annual System-Wide IDP Planning Process" on its current "Area Study Planning Process" and identified where stakeholder engagement specific to DER would be added. The Company's proposed Planning Analysis integrates the integrated distribution plan ("IDP") process into the Company's well developed area study planning process. As outlined in more detail below, Stages 1 and 2 of the Planning Analysis will proceed sequentially to produce results that will be used as inputs for Stage 3 each year and will prioritize the areas to be studied that year. Step 3 is the Annual Area Planning Studies for that year. Where appropriate, Stage 3 will provide the recommended plan and details necessary for the Company to develop a CIP proposal in Stage 4 for one or more of the areas studied.[7]

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[6] As the Company discussed in its Initial Comments, when the Company transitions to IDP, the IDP must be accompanied and informed by a transmission study on the same areas to be complete, useful, and truly integrated. Specifically, development of the transmission infrastructure required to support distribution infrastructure development that is driven primarily by forecasted DG must be able to be advanced before the Company has a clear understanding of specific DG applications for interconnection. The Company will need to work with ISO-NE to understand how such studies will be conducted and results will be preserved; New England states have begun a regional planning effort to better align the regional wholesale markets with the New England states' clean energy mandates. National Grid anticipates transitioning to an IDP through implementation of the Planning Analysis. (Initial Comments at 9 and footnote 9)

[7] Stage 4 was called "CIP Pre-Approval Process" in the Company's Reply Comments; the name has been changed to more accurately reflect the activities during this Stage.

Figure 1 shows an overview of the Stages and Table 1 provides a high-level summary of the deliverables for each Stage.

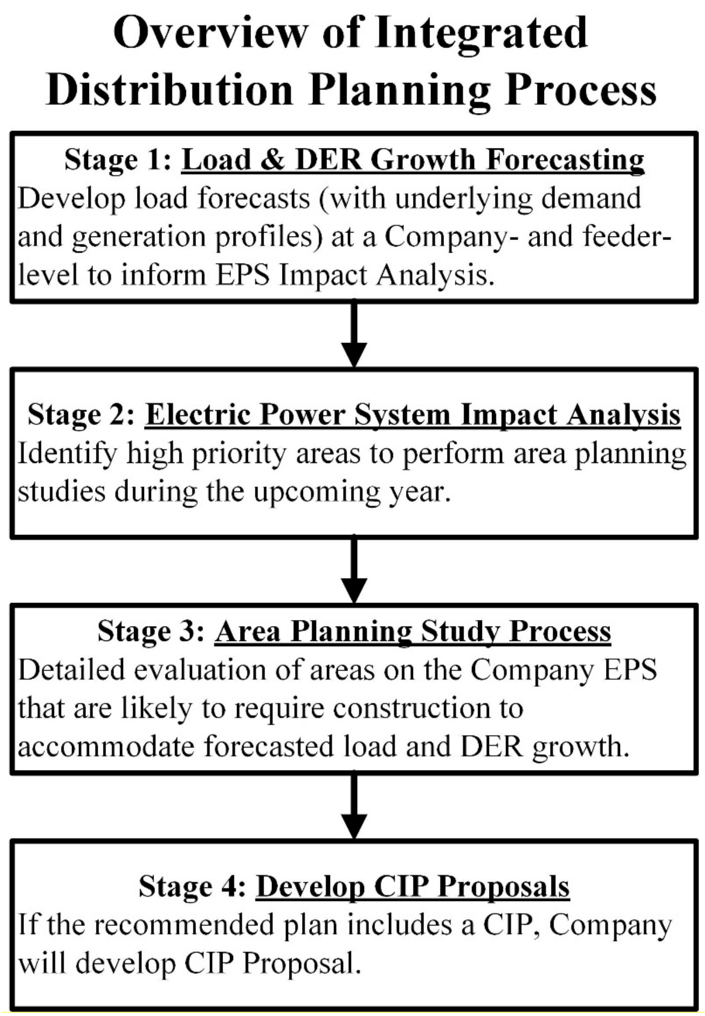

Figure 1: Overview of Integrated Distribution Planning Process

Table 1: Planning Analysis Scope Summary

Stage	Estimated Deliverables	Estimated Timeline
Stage 1: Load & DER Growth Forecasting	• Summary of local plans, issues, challenges, and opportunities for DER informed by stakeholder input • Company-wide load forecast scenarios • Company-wide annual hourly load forecast • Technical and economic potential for DG development by area ("DG Market Adoption Inputs") • Feeder-level annual hourly load forecast	6 Months (excluding Task 4)
Stage 2: Electric Power System Impact Analysis	• Identification of DG enablement network constraints for distribution • Suitability and ranking criteria development • Technical subject matter expert ("SME") consultation about results of Stage 2 to inform Company activities in Stage 3	3 Months

Stage 3: Area Planning Study Process	• Area study report for particular area studied containing:
	  o Study basis and assumptions
	  o Issue identification summary
	  o Summary of alternatives considered
	  o Estimates
	  o Recommended plan and selection rationale
	• Technical SME consultation throughout the study process
		12 Months

Stage 4: Develop CIP Proposals	• Develop one or more CIP proposals specific to the area, if warranted by the Area Planning Study	TBD

The proposed Planning Analysis will identify T&D infrastructure investments needed to interconnect pending DG and forecasted future DG in the Company's service territory in addition to providing additional benefits, including:

- Clean Energy Goal Alignment: The proposed Load & DER Growth Forecasting (Stage 1) will utilize new tools and internal processes for developing DER scenarios and feeder-level load forecasts to enable more effective T&D system modeling. These new tools and processes will contribute to a more granular and synergistic planning process, which will assist the Company in planning for the T&D infrastructure needed in specific areas to support forecasted DER development in those areas that are aligned with achieving the Commonwealth's clean energy goals.

- Electric System Readiness: The proposed Electric Power System Impact Analysis (Stage 2) will consider a wide range of potential DG impacts on the current and future electric system, while also taking into consideration capacity, reliability, asset, operational, and safety issues, and climate change adaptation and resiliency, to help the Company be prepared to deploy the necessary solutions to enable and maintain clean, safe, reliable, and affordable energy to all our customers.
- Stakeholder Responsiveness: The proposed overall Planning Analysis will incorporate external stakeholder input into Load & DER Growth Forecasting (Stage 1) and the Area Planning Study, which includes Plan Development and the Recommended Plan Selection (Stage 3). See Reply Comments at 5-11 for a fuller discussion of stakeholder input into the planning process.
- Cost Effectiveness: The proposed External Stakeholder Engagement tasks are designed to solicit meaningful input into where future DG is likely to locate, facilitating CIP proposals in areas in which enabled capacity for future DG is likely to be fully utilized, which will be more cost-effective for all customers.

A. Stage 1: Load & DER Growth Forecasting

Stage 1 will develop load[8] forecasting scenarios[9] for future DG and baseline loading (e.g., non-DG types of DERs and existing connected DG that will impact load on the Company EPS), including creating feeder-level forecasts based on customer and feeder information (e.g., current and pending DG, customer demographics, and feeder metrics). Temporally, the forecasts will range from hourly forecasts to multi-year annual projections.[10] To achieve this, a number of enhancements to the Company's historical current forecasting approach will be required. These enhancements are described in greater detail in the sections below for each of the tasks in Stage 1.

The proposed work for Stage 1will be carried out through five tasks, each of which has a deliverable. An overview of the tasks for Stage 1 is shown in Figure 2.

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8 For the purposes of this filing, National Grid use the term "load" in the broadest sense, referring to the net loading of the EPS (or feeder or substation) when coincident energy usage and generation cancel each other out. Where the distinction is required, the Company will use the term "demand" when referring to energy usage by customers (which depending on the context may refer to traditional energy usage, non-DG types of DERs, or energy storage charging from the grid) and "generation" when referring to a distributed generator or energy storage system that is generating power.

9 These "forecasting scenarios" represent various permutations of potential future levels of demand (including non-DG DER energy usage) as well as potential future DG saturation on the EPS, which results in a net amount of load on a feeder (or substation bus) as well as the component portions of that net load that are attributable to each category of either demand or generation. As an example, these permutations might include two scenarios with low baseline growth rate for demand (e.g. slow adoption of DERs and/or traditional loads), the first of which considers a high adoption rate for DG (e.g. climate goals are primarily met with distribution level solar and storage) and a second which considers a lower adoption rate for DG (e.g., climate goals are met primarily via other technologies, such as offshore wind).

10 The Company has hourly data (8760 data) available in some places on its system but will not have hourly data available throughout its EPS until the information technology and communications investments the Company will request in its next Grid Modernization filing have been made. National Grid also cautions that even for areas where such data is available, its use in developing future forecast scenarios is not a substitute for, and should not be conflated with, the existing need for protection equipment at individual DG sites to limit export capacity.

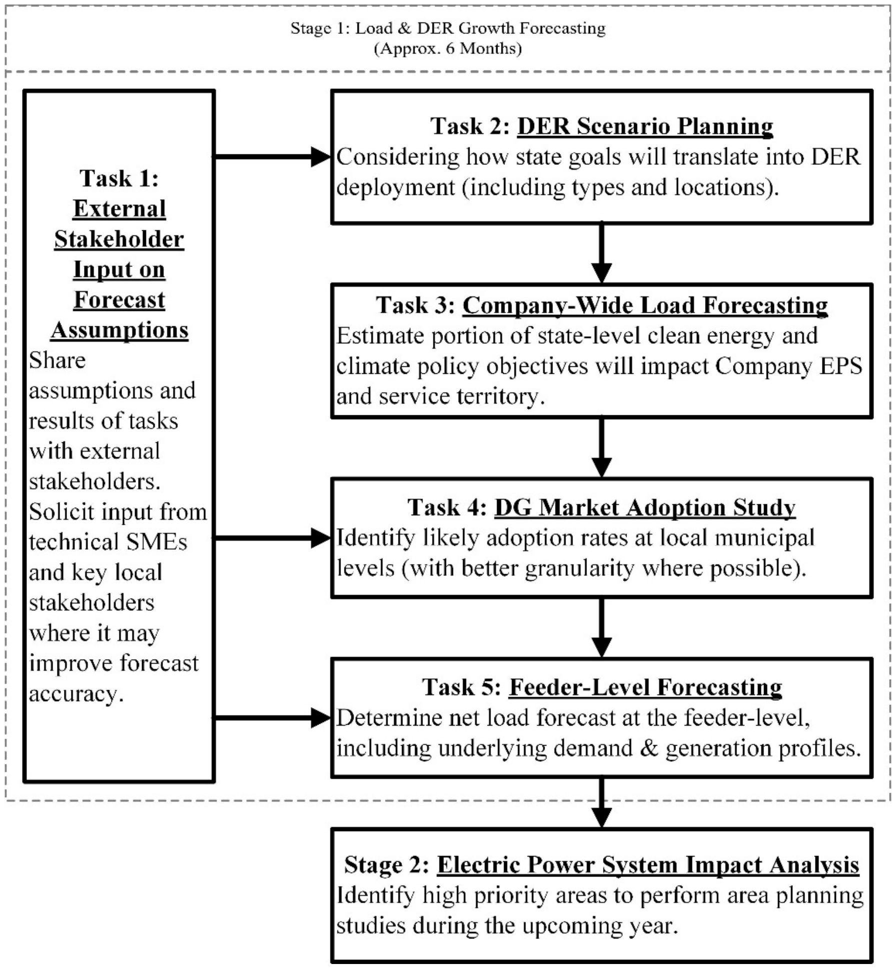

Figure 2: Diagram of Stage 1 Tasks

Figure 2 provides an illustrative representation of the dependencies between the five tasks within Stage 1. The Company expects to determine the optimal sequence of tasks and number of iterations for each of the tasks in Stage 1 during the first few years that it performs this process, including whether the tasks should happen sequentially or in parallel and whether some or all of the tasks are included in feedback loops for iterative revisions.

The total estimated time period for the initial implementation of Stage 1 is approximately 6 months, excluding Task 4.

1. Task 1: External Stakeholder Input on Forecast Assumptions

In Task 1, the Company will conduct outreach to key stakeholder groups to better understand DER development plans, issues, challenges, and opportunities across the Commonwealth generally and within the Company's service territory specifically, so the Company can incorporate a local perspective in the Company's forecasting process. In this task, the Company will seek to understand developer, municipal, state agency, conservation group, or other stakeholder perspectives on DG and other DER projects. This input will include the Commonwealth's projections for DG and DER in achieving GHG reductions and Net Zero status by 2050, taking into account the Massachusetts Interim Clean Energy and Climate Plan for 2030,[11] the Massachusetts 2050 Decarbonization Roadmap[12] and An Act creating a next-generation roadmap for Massachusetts climate policy.[13] This could a forecast of the future potential for solar and other DERs in Massachusetts broadly and on the Company EPS specifically, including existing incentive programs, stated resource targets or plans, siting ordinances, current municipal limitations/moratoriums, and non-market impacts and concerns.[14] For example, engagement with state agencies will provide a better understanding of the most appropriate customer DER deployment assumptions to use for each DER scenario, including expectations for future programmatic support. Engagement with DG developer groups will enable a better understanding of developer and customer intentions concerning the size and location of future proposed DG projects and the timing and efficacy of new technologies, such as the availability and reliability of advanced smart inverter functionality, they foresee adopting. Engagement with municipal and

[11] Massachusetts Interim Clean Energy and Climate Plan for 2030
[12] Massachusetts 2050 Decarbonization Roadmap
[13] Chapter 8 of the Acts of 2021
[14] See Initial Comments at 48-53 concerning the challenges that must be overcome to realize the full potential of the DER long-term planning process envisioned by this docket.

conservation groups will provide a better understanding of the general willingness of specific municipalities to allow or discourage DER development.

External stakeholders will also have an opportunity to review the Company's intended forecasting methodology and specific state, Company and feeder-level forecasting assumptions. The Company will engage stakeholders on the methodology in advance of its planning efforts, with such methodology refreshed if the Company determines necessary. However, because many aspects of the system planning process are technical in nature, the Company will primarily solicit feedback regarding the forecasting review process from technical subject matter experts and key stakeholders with local knowledge about the areas being studied. This approach will help ensure the Company's planning sufficiently considers developer and customer intentions as well as the Commonwealth's evolving clean energy roadmaps, local information, and other external stakeholder input.

Stakeholder engagement could include a series of presentations, with Q&A, potentially supplemented by surveys as needed. Where appropriate, the Company may also circulate project- or area-specific updates and deliverables to key stakeholders in a specific area.

Key Deliverable for Task 1: Summary of DER plans, issues, challenges, and opportunities across the State and in the Company's service territory.

2. Task 2: DER Scenario Planning

Task 1 will first evaluate the most likely customer DER adoption scenarios that can achieve the Commonwealth's clean energy goals and then establish DER scenarios on a rolling 10-year basis based on assumptions for future customer DER adoption, such as type, size, technology, and configuration. These scenarios will be used to evaluate the broadest anticipated range of DER impacts on the distribution system in the future without performing detailed analysis on all possible scenarios.

Preliminary analysis by National Grid and others already shows significant load growth could be possible if customer adoption of vehicle and heat electrification are widespread.[15,16] Demand growth could be particularly significant in urban and other densely populated areas due to the expected future increased adoption of electric vehicles ("EVs") and electric heat pumps ("EHPs") by residential customers. The impact of these non-DG types of DERs will need to be considered when developing an accurate baseline of comparison for the impact of future DG growth on the Company EPS and to determine what might be in scope for a CIP fee.[17]

This task will leverage the Commonwealth's clean energy goals and external stakeholder engagement from Task 1 to determine the most appropriate DER adoption assumptions to use for the scenarios. Factors that may be considered when developing DER adoption scenarios include:

- The role of various DERs in meeting State goals (outputs from Task 1)
- Programmatic and and regulatory supports for DERs
- DER market drivers, including ISO-NE markets
- DER technology drivers
- Non-State incentives and financing drivers, such as federal tax policy incentives

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15 *Achieving 80% GHG Reduction in New England by 2050*, The Brattle Group for the Coalition for Community Solar Access, Sept. 2019, at v and 20.
Note that 80% GHG reduction by 2050 is a New England goal, not a Massachusetts specific 2050 goal.

16 Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts, 2050 Decarbonization Roadmap Study, December 2020

17 This would help to establish the baseline for distinguishing between DG Reserve Capacity Improvements and Multi-Value Improvements discussed in Reply Comments at 12-13.

After an internal review of each potential scenario and their respective probabilities, the Company will select which DER scenarios to utilize in the Company-wide load forecasting process.

Key Deliverable for Task 2: Two or more Company-wide load forecast scenarios based on probabilistic assumptions for future DG growth relative to the overall EPS load, including broader non-DG types of DER adoption.

3. Task 3: Company-Wide Load Forecasting

The Company has historically developed load[18] forecasts that focused only on peak loading. Recent Company forecasts consider a number of load periods, including seasonal peak and minimum load periods. For the proposed load forecasting, annual hourly load profiles will be created for each DER type using the DER scenarios. Each DER component will have its own projection for future growth, allowing the Company to assess each DER's impact individually as well as on an integrated basis. This enables the disaggregation of net load so that the contributions of all load components can be understood across both time and space. Hourly forecasts illustrate not just the changing magnitude of peak and minimum loads but are valuable for showing how the timing of peak and minimum load changes over time. Examining the magnitude and timing of loads across the seasons and days is important for assessing the impacts of different types of DER.

First, Task 3 will forecast Company-wide annual hourly load profiles for each DER type using DER performance models and appropriate DER and load forecasting assumptions. Hourly load forecasts will be developed based on the baseline year actual system load plus economic load growth, energy efficiency ("EE") impacts, and individual DER load forecasts. Next, each load component (baseline load, economic growth, EE, EV, EHP, DG) will be scaled per the various

[18] See footnote 8 which defines the meaning of "load" in this proposal.

customer DER adoption scenarios and added together to forecast Company-wide annual hourly load profiles through the next 10-year period.

Key Deliverable for Task 3: Company-wide annual hourly net load profile forecasts with underlying demand and generation profile forecasts over the next 10-year period for each DER adoption scenario.

4. Contingent Task 4: DG Market Adoption Inputs

To most efficiently implement Task 4, National Grid will explore a collaborative approach with other entities that also might benefit from this information, including whether an external consultant would be needed to carry out this effort. Task 4 is contingent on collaborations and cost-sharing with other interested entities; if that is not feasible, Task 4 will not be performed.

In Task 4, the Company will seek inputs from knowledgeable external sources about the technical and economic potential for DG development by area. Task 4 will help determine the specific municipalities where DG that can help achieve the Commonwealth's clean energy and climate policy objectives is likely to locate in the future, considering the DER scenarios developed in Task 2 and Company-wide forecast scenarios from Task 3. Where feasible, specific locations within a municipality conducive to DG development will be identified.

It is unlikely the DG Market Adoption Inputs could be completed during the initial implementation of the long-term planning process in the first year, so this deliverable will be used to inform future annual planning processes. The Company believes this study will be beneficial to the overall analysis; however, it is not a critical path item in the first year of implementation because the first year will focus on areas that already have significant DG saturation due to interconnected Facilities and DG applications in the interconnection queue. In subsequent years of the annual planning process, Task 4 will provide valuable inputs to Task 1 and Task 5.

The purpose of the DG Market Adoption Inputs is to reduce the considerable uncertainty that exists today about where future DG development will occur in the Commonwealth. Currently, the lowest cost locations for DG in National Grid's service territory are generally in rural areas with lower-cost land and acreage sufficiently large to site solar farms, which typically are far from load centers. Although relatively lower property cost is currently a major driver for the siting of DG, Task 4 will consider future technology, policy, and market conditions that could impact that paradigm.

From an ideal process perspective, the DG Market Adoption Inputs will first involve an evaluation of the technical and economic potential of various DG development types for the electric power systems in Massachusetts, and then determine which portion of the overall state-wide adoption is likely to occur on the Company EPS, including feeder level deployment projections.

Ideally Task 4 will leverage municipal-level (and perhaps more granular) information to estimate the technical potential for various types of retail-scale solar energy (rooftop, landfill, gravel pit, brownfield, commercial and industrial ground-mounted, and carport solar) in Massachusetts. Task 4 will consider relevant studies, such as Massachusetts Energy Pathways to Deep Decarbonization studies referenced above, and DG resource cost evaluations, and augment those with Massachusetts-specific information on DG incentive programs, feeder-level hosting capacity, and other pertinent local information to estimate the economic potential for all major types of DG development throughout Massachusetts.

Finally, Task 4 will incorporate external stakeholder input, including from Task 1, on DER plans, siting ordinances, current municipal limitations/moratoria, non-market siting considerations such as environmental and historic conversation districts, and in general how open specific municipalities are to renewable generation development.[19]

Key Deliverable for Task 4: Technical and economic potential for each type of DG development for each of the feeders in National Grid's service territory (based on an anticipated portion of state-wide DG deployments) through the next 10 years.

5. Task 5: Feeder-Level Forecasting

After developing annual hourly load forecasts at the Company-wide level in Task 3, the Company will develop tools and methodologies to allocate the Company-wide load profiles down to the feeder-level based on customer and feeder information. Examples of customer and feeder information that will be considered include current and pending DG, customer demographics, and feeder metrics, such as urban vs rural, length of feeder, historic demand and generation data. After the first year, Task 4 will primarily inform the technical and economic potential for DG used for the feeder-level forecast.

Key Deliverable for Task 5: Feeder-level hourly load forecast using current and pending DG, customer and feeder information, and technical and economic potentials (when available).

B. Stage 2: Electric Power System Impact Analysis

The Company has well-established and robust planning processes in place to make proactive infrastructure investments to support load, asset condition, and reliability improvements. The processes conditionally consider proactive investments to accommodate DER interconnection if they do not result in any increased cost to an infrastructure investment driven by other factors mentioned above. The process additions proposed in Stage 2 focus on increasing the Company's

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[19] As discussed in the Initial Comments at 50-52, the Company is exploring site-suitability criteria and a streamlined permitting process for siting infrastructure.

capabilities to make proactive system investments to address network constraints which may otherwise inhibit the growth of DG. At the core of this analysis will be the advancements in feeder level forecasting noted in Stage 1. Feeder leveling forecasting enables a granular system perspective, which can then be consolidated to the substation and sub-transmission levels.

Figure 4 provides a diagram of the tasks in Stage 2, which at this time consist of a single task. After the initial implementation of the end-to-end Planning Analysis process, the Company expects Stage 2 may evolve over time to better inform the more detailed Area Planning Studies in Stage 3.

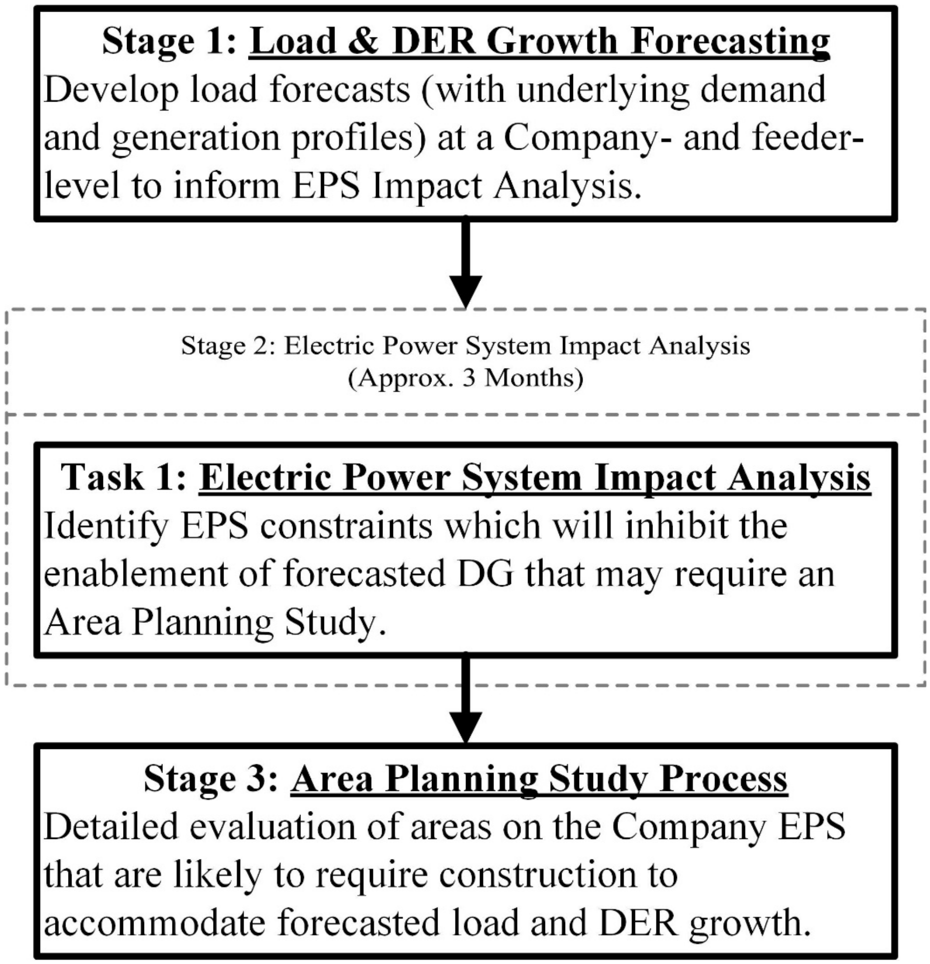

Figure 4: Diagram of Stage 2: Electric Power System Impact Analysis

1. Task 1: Electric Power System Impact Analysis

Stage 2 will supplement the existing planning processes by identifying network constraints which inhibit DG enablement. This identification of network constraints for consideration in the subsequent solution identification component of Stage 3 will be an evolving process that continually builds upon advancements in forecasting, external stakeholder feedback, and market adoption studies among other inputs. Initially, the Company expects to focus the analysis on identification of thermal constraints that inhibit DG growth, which typically equate to the largest required investments. These high cost constraints include feeder conductors and substation transformer thermal limitations. The Company expects to advance the granularity of the analysis in step with advancements in the analysis inputs and modeling capabilities.

Successful integration of these constraints limiting DG enablement with the Company's traditional area planning and solution identification processes described in Stage 3 will be key to delivering projects that provide mutli-values and enable capacity for future DG. As noted in the Initial Comments, significant efficiencies and multiple benefits can be gained when evaluation of infrastructure improvements is conducted in a holistic manner that incorporates a multitude of factors, such as DG enablement, asset condition, loading, and system reliability considerations. This objective will necessitate the development of a suitability screening and ranking mechanism to inform prioritization of area planning studies which will integrate the traditional grid needs (load growth, reliability, asset condition) and DG enablement into an optimal project solution. The resulting incremental investment to realize the DG enablement benefit would be rolled up to a zonal level that generally aligns with the Company's 48 planning areas on an as needed basis for subsequent cost recovery.

C. Stage 3: Area Planning Study Process

Figure 5 is a modified version of the diagram presented in the Reply Comments at 8. The modifications result from National Grid's continued efforts to refine inclusion of DG into its existing planning processes since the Reply Comments were filed.

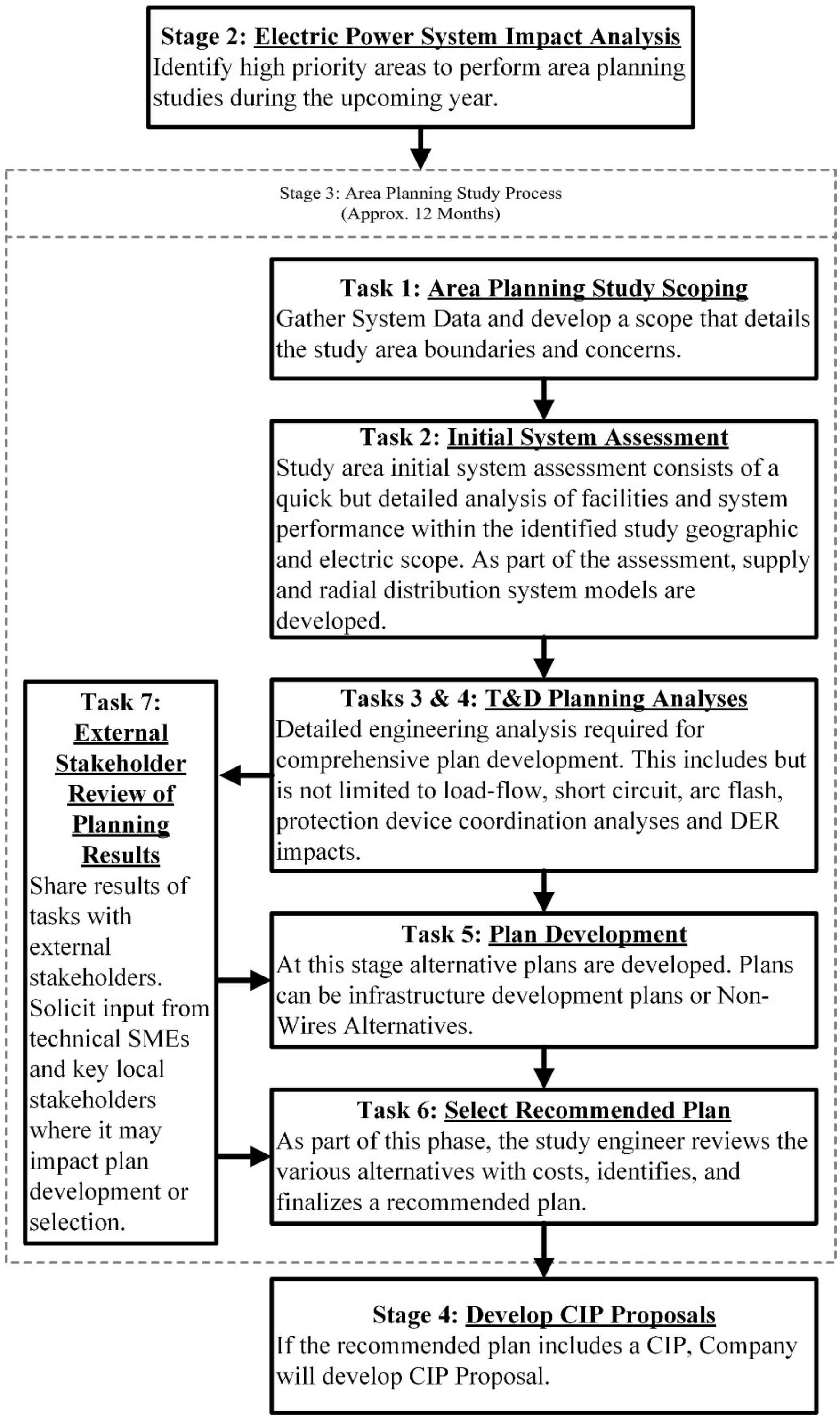

Figure 5: Diagram of Stage 3: Area Planning Study Process

EPS Impact Analysis informs the prioritization of which area planning studies should be completed in a given year. When the EPS Impact Analysis highlights an area that has capacity constraints at a level of severity and/or complexity that warrants a detailed and comprehensive review, that area is identified as needing an area planning study. Other prompts for an area planning study include the identification of asset condition issues, reliability issues, or a large new customer load request. The area planning study process steps are described in detail below.

1. Task 1: Area Planning Study Scoping

Scoping involves setting the study electrical and physical boundaries and determining study inputs and assumptions. Although National Grid has existing study areas with set boundaries, a review is conducted to determine if circuits at the fringe of the boundaries should or should not be included. Typical study inputs include the forecast, with any of the proposed modifications described above when they are available, planning criteria, current programs, historical reliability data, asset condition data, recently completed projects, and the electric system data. Area studies also consider available environmental data such as flood plain maps and recent inspection and maintenance reports to assess potential resiliency needs. The main information is the latest electric system topography and connectivity along with the attribute data for the connected components. In addition to traditional attribute data such as fault current rating and protection settings, it is now important to gather new attributes such as equipment sensing capabilities, data collection capabilities, and communication capabilities. This type of information is collected for all the conductor, cable, fuse, breaker, capacitor, relay, switch, and transformer components of the system to create the system model. Next, existing DG connectivity and attribute information is gathered and added to the model. Finally, in-queue DG information is entered into the model.

Task 1 can take up to two months depending on the size and complexity of the electric system model.

Key Deliverable for Task 1: Completion of system model updates for area studies.

2. Task 2: Initial System Assessment

Once the system models are complete, the initial system assessment can begin. Task 2 involves running unbalanced three-phase steady-state analysis to determine distribution feeder normal loading, contingency loading, and voltage issues. A separate three-phase balanced load flow model is used for substation and sub-transmission analysis. A third model is used for fault current analysis. The main purpose of this Task is to test and verify the models and get initial results to help refine the detailed analysis effort.

Task 2 typically takes one month to complete.

Key Deliverable for Task 2: Initial study results of a specific area study.

3. Task 3: Distribution Planning Analysis

This Distribution Planning Analysis task uses the verified models to determine detailed normal loading, contingency loading, voltage, protection coordination, arc flash, and reactive power flow issues. The results of these models build upon the initial system assessment and are used to determine the section or nodal level issues across the forecast period (typically 15 years). National Grid is in the process of evolving this task to include transient analysis and time-series analysis (8,760 hours per year), following upgrades to the current software tools and data processing power. Energy storage operating schedules also require new modeling and analysis techniques.

This task typically takes four months to complete but could be complicated by time-series and DG scenario analysis. National Grid expects to identify issues without forecasted DG and then with forecasted DG to help differentiate demand-based and generation-based concerns. This effectively doubles the level of effort compared to the existing analysis. Currently, peak and light load cases are analyzed. However, initial reviews of energy storage operating schedules indicate that transition periods where the energy storage system can change from charge to discharge states requires a new focus.

Key Deliverable for Task 3: Detailed study results of a specific distribution system area study and identification of area needs.

4. Task 4: Transmission Planning Analysis

The Company's transmission provider, New England Power Company ("NEP") will initiate a study in support of the annual distribution system impact study consistent with the North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Corporation ("NPCC"), ISO-NE, and National Grid requirements. The ISO-NE Planning Procedure 5-6 (PP5-6) and ISO-NE Technical Planning Guide will be utilized for this purpose. These documents will help advise on the treatment of all of the inputs to be assumed in the study following the confirmed location or points of interconnection of the forecasted generation or demand on the system determined in Task 3. In addition, Task 3 will define all of the proposed distribution infrastructure changes to accommodate what is forecasted in a 10-year timeframe, and for the purposes of Task 4, NEP will assume that such distribution infrastructure changes would be in place.

The transmission analysis for the forecasted proposed DER over a 10-year timeframe will include an assessment to ensure that all of the elements in the transmission network will operate within their respective thermal and voltage limits for various system conditions while considering the following:

- Load forecast
- Reliability over a range of generation patterns and transfer levels
- System load levels (peak, shoulder, light and minimum load)
- Public asset condition or system upgrades planned to be in-service within the 10-year timeframe
- Coordination with other ongoing studies in the area
- Existing and Forward Capacity Market-cleared supply resources
- Generators with ongoing studies in the ISO-NE queue
- All applicable NERC, NPCC and ISO-NE transmission planning reliability standards
- Interconnected and approved DER modeled in study base cases at appropriate output levels

The upgrades with the most value to the affected stakeholders will be developed in this task based on this analysis to mitigate any of the adverse impacts that are identified on the transmission system. Consistent with previous large Affected System Operator ("ASO") studies, each adverse impact would prompt a variety of different types of upgrades for consideration. In the past, the most cost effective technically appropriate solutions have included the developers adopting a particular ride-through setting prescribed by National Grid that would address the adverse impacts in the study (a recommendation consistent with the industry standards), and the utilization of smart capacitor banks on the distribution systems, resolving significant voltage issues identified on the transmission system. Going forward, the scope of the upgrade evaluation will continue to include both transmission and distribution solutions with a range of technical and cost profiles, such as dynamic voltage support devices, reconductoring of transmission lines, substation upgrades, etc., so the most appropriate proposal can be selected to address issues identified on the transmission system.

The transmission study will be conducted with consideration of the timeframes referenced in ISO-NE Planning Procedure 5-3; however, with respect to this particular Task, NEP will only conduct a Steady State analysis. This will ensure that any significant thermal or voltage issues are identified and upgrades are developed as appropriate.

Key Deliverable for Task 4: Assessment of the transmission system that identifies system needs and potential solutions to address transmission system issues.

5. Task 5: Plan Development

With the detailed T&D issues identified, alternative solutions are developed. The area planner first considers no-cost or low-cost solutions such as system reconfiguration or optimization. Then alternative infrastructure and non-wires alternatives are developed. The plans should be technically comparable to the extent possible. Infrastructure and non-wires alternatives can be combined to create comparable plans. Last, technical scope documents and estimates are developed for all alternatives.

National Grid has begun efforts to determine ancillary benefits beyond addressing electric system needs. These benefits include overall energy reduction, energy or capacity price impacts, and emission reduction potential.

Task 5 typically takes three months to complete with one month allocated to consultation. This timeline could be impacted by complex ancillary benefit calculation requirements, and the possible need for request-for-proposal procedures to gather non-wires alternative estimates.

Key Deliverable for Task 5: Solution options to address distribution system needs identified in the Distribution Planning Analysis (Task 3).

6. Task 6: Select Recommended Plan

Once the alternatives are developed, the recommended plan is selected. This has been traditionally determined by selecting the least cost plan among technically comparable options. Where technically comparable plans are not possible, the least cost, best fit for purpose (technically superior) plan is selected. National Grid plans to transition to a cost/benefit selection method as suitable calculation methods are determined. Final report documentation is included in this Task.

Task 6 typically takes two months to complete, with one month allocated to consultation.

Key Deliverable for Task 6: Recommended solution option selected from alternative solutions and cost estimates for each project.

7. Task 7: External Stakeholder Review of Planning Results

The three steps of the planning process where the Company, and the other EDCs, anticipate stakeholders could provide meaningful input are Area Planning Study Scoping, Plan Development and a targeted review of the Recommended Plan. These are the steps in the Company's current planning process at which the Company solicits internal stakeholder input. The Company will align external subject matter experts' reviews with its existing internal consultation process to incorporate a wider array of subject matter experts into the process.

- Area Planning Study Scoping is the step at which the Company gathers system data and develops a scope that details the study boundaries and concerns. Alternative options for the plan are developed. The Company will engage internal and external stakeholders to review the scope information to ensure suitability with the planning goals.

- Plan Development is the step at which alternative options for the plan are developed. When the Company has finished developing the options, the Company will engage internal and external stakeholders to review the developed alternatives to ensure a suitable set of options are considered.
- Plan Selections is the step at which the costs of the options have been estimated and the Company has identified the least-cost, best-fit plan. The Company will engage internal and external stakeholders to review the costs of all the alternatives and describe the decisions that led to the recommended option for the plan.

Figure 5, above, illustrates the steps in the planning process where external stakeholder engagement could provide meaningful input to supplement the Company's existing internal stakeholder process.

D. Stage 4: CIP Proposals

In Stage 4 the Company will develop one or more CIP proposals specific to the area, if warranted by the Area Planning Study.

III. PROCEDURAL STEPS THE COMPANY WILL TAKE INTERNALLY TO IMPLEMENT THE PROPOSAL

Currently the Company conducts routine analyses on its distribution system in the form of Capacity Reviews and Area Planning Studies.

The Capacity Review is completed for all 48 planning areas on an annual schedule and identifies thermal capacity constraints, assesses system performance to ensure the network maintains adequate delivery voltage, and assesses the capability of the network to respond to contingencies that might occur. The Capacity Reviews will be expanded to include the results of the Electric Power System Impact Analysis (Stage 2) and the suitability screening and ranking mechanism to inform prioritization of Area Planning Studies. When Capacity Reviews highlight an area that has constraints of a level where a detailed and comprehensive analysis is warranted, that area is identified as needing an Area Planning Study. Typically, multiple Area Studies are completed in parallel on a 5 to 10 year cycle. The Company will evaluate the need for additional resources should the need arise to increase the number of studies occurring in parallel.

In addition, the Company is identifying the internal groups who will be responsible for implementing this proposal following Department approval and is continuing its efforts to refine inclusion of DG into its existing planning processes.

IV. HOW THE ANALYSIS WILL CONSIDER THE COMMONWEALTH'S CLEAN ENERGY AND CLIMATE POLICY OBJECTIVES, INCLUDING CLIMATE CHANGE MITIGATION, ADAPTATION, AND RESILIENCE

Meeting the State's clean energy goals will require a significant amount of renewable generation, beneficial electrification, and other DER integrations that will likely impact both the T&D systems. As highlighted in the Company's Initial Comments, understanding the role policymakers expect various DERs to play in meeting the State's clean energy goals is a critical first step in creating and then assessing the overall forecast for such DERs, and the subsequent need for EPS upgrades. That input is essential to guide the Company's analysis and proposed solutions, including consideration of system resiliency improvements to mitigate the effects of climate change and address traditional EPS constraints. The Company also realizes that the development of DER scenarios and associated integration upgrades to alleviate EPS constraints could be helpful in crafting future policy and regulatory supports for reaching the State's 2030 and 2050 GHG reduction goals. As such, the Company expects that the outputs from its and other EDCs' system analyses, as well as the proposed DG Market Adoption Inputs, would provide critical information that could guide how to most cost-effectively and quickly expand the infrastructure needed to interconnect DG Facilities and future potential DG in that broader context. Specifically, while the Commonwealth has laid out a proposed additional 2,000 MW of solar deployment for achieving its 2030 interim carbon-emissions goals, beyond the current programmatic support through the expansion of the SMART Program for 3,200 MW of solar state-wide, better defined and focused State attention on the role of DG resources and solar in particular is needed to provide the essential inputs the Company will need for this long-term planning effort.

National Grid looks forward to working with policymakers and stakeholders generally in providing information relevant to inform that iterative public process, and to shape a forecast for DG Facility deployment that is grounded in the trade-offs between technical potential, the relative cost of reducing carbon emissions from different resources, and the desire to conserve natural resources at the state and local levels.

V. STAKEHOLDER PARTICIPATION

National Grid agrees with the direction the Department has proposed in the Order and Straw Proposal, and the Company is excited at the opportunities that such a pivot in approach may open for the Company to work with the DG industry stakeholders and state agencies to progress the clean energy and climate policy objectives of the Commonwealth. National Grid intends to seek out opportunities to productively incorporate external stakeholder feedback in the Planning Analysis processes at the three points identified in its Reply Comments and elaborated on in this proposal (see Stage 1, Task 1 and Stage 3, Task 7 for details), especially where stakeholders with technical expertise or detailed knowledge of localized concerns are unavailable to the Company internally.

IV. TIMELINE FOR IMPLEMENTATION

Table 2 below provides an ilustrative schedule that depicts the estimated timeline for National Grid's initial implementation of the Planning Analysis process once the Department approves implementation. The Company would need a certain amount of flexibility to align the tasks outlined in this proposal with its traditional planning cycles (especially with respect to the availability of load forecast data).

Stage #	Task Description	Month																	
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1.0	**Load & DER Growth Forecasting**																		
	Task 1: External Stakeholder Input on Forecast Assumptions																		
	Task 2: DER Scenario Planning																		
	Task 3: Company-Wide Load Forecasting																		
	Task 4: DG Market Adoption Study*																		
	Task 5: Feeder-Level Forecasting																		
2.0	**Electric Power System Impact Analysis**																		
	Task 1: Distribution Impact Analysis																		
3.0	**Area Planning Study Process**																		
	Task 1: Area Planning Study Scoping																		
	Task 2: Initial System Assessment																		
	Task 3: Distribution Planning Analysis																		
	Task 4: Transmission Planning Analysis**																		
	Task 5: Plan Development																		
	Task 6: Select Recommended Plan																		
	Task 7: External Stakeholder Review of Planning Results																		
4.0	**Stage 4: CIP Pre-Approval Process**																		
	Task 1: CIP Pre-Approval Process																		

* Results from the Renewable DG Market Adoption Study will be used to inform future annual planning analyses

** The transmission planning analysis tasks could take between 6-9 months depending on the level of upgrades required

Table 2: Estimated Planning Analysis Timeline for Initial Implementation

VII. CONCLUSION

National Grid appreciates the opportunity to submit its system planning analysis proposal in response to the H.O. Memorandum, and looks forward to continued engagement on the issues the Department raised.

Respectfully Submitted,

MASSACHUSETTS ELECTRIC COMPANY
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