nationalgrid

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Senior Counsel

February 22, 2021

VIA ELECTRONIC MAIL

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

RE: Docket 5098 - Proposed FY 2022 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to OER Data Requests – Set 1</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please find the Company's responses to the Office of Energy Resources' ("OER") First Set of Data Requests in the above-referenced matter.

The Company received an extension to respond to data request OER 1-19 to February 26, 2021.

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 5098 Service List
John Bell, Division
Greg Booth, Division
Tiffany Parenteau, Esq.
Al Contente, Division

[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by an original and five hard copies filed with the Clerk within 24 hours of the electronic filing.

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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

February 22, 2021
Date

Docket No. 5098 - National Grid's Electric ISR Plan FY 2022
Service List as of 2/10/2021

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OER 1-1

Request:

Chart 2 on Bates Page 47 states "stakeholder input" is one component of the fifth step. Please describe who the stakeholders are, when they were/will be engaged, and how.

Response:

In the Capital Work Plan Process, a cross-functional project team is assembled to assist in the development of the work plan. The team assembled typically includes, but is not limited to, the following internal National Grid departments:

- Distribution Planning and Asset Management
- Substation O&M Services
- Transmission Planning and Asset Management
- Operations
- Transmission and Distribution Regional Control Center
- Project Development and Project Management
- Investment Planning
- Resource Planning
- Project Controls
- Electric Business Unit Performance and Strategy
- Regulation & Pricing – New England
- Finance
- Procurement
- Community and Customer Management

Team members provide input through informal meetings and through formal technical review sessions.

Prepared by or under the supervision of: Caitlin Broderick and Patricia Easterly

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OER 1-2

Request:

On Bates Page 55, Stage 3 of area planning studies references a "larger stakeholder group."

a. Who are the stakeholders in the implied smaller stakeholder group?
b. Who are the additional stakeholders who comprise the larger stakeholder group?

Response:

a. During area study stages 1 and 2, the engineer engages individual subject matter experts who are considered the smaller stakeholder group. This could include any of the stakeholders included in the "larger stakeholder group".

b. In stage 3, a formal kickoff meeting is held with multiple departments. This larger stakeholder group consists of representative from internal National Grid Departments that form the study team. These departments include but are not limited to:

    - Distribution Planning and Asset Management Field Engineers (DPAM)
    - Substation O&M Services
    - Transmission Planning and Asset Management
    - Operations
    - Transmission and Distribution Regional Control Center
    - Distribution Line Design
    - Substation Engineering and Design
    - Transmission Line Design
    - Community and Customer Management
    - Non-wires alternative team

OER 1-3

Request:

In which stage(s) of area planning studies (i) are the following parties allowed to participate and (ii) do the following parties participate?

a. Division of Public Utilities and Carriers (DPUC)
b. Public Utilities Commission (PUC)
c. Office of Energy Resources (OER)
d. Other parties exempting National Grid, DPUC, PUC, and OER

Response:

a. In accordance with the RI state statute that adopted Revenue Decoupling and the ISR (§ 39-1-27.7.1), the Company and the Division of Public Utilities and Carriers (DPUC) negotiate every year to agree on an annual capital plan that is submitted to the RI PUC.

   As part of that process the DPUC has the opportunity to participate in any stage of the Company's area study process but the Company recommends the potential for involvement in three stages but with most or all involvement recommended later in the process so that the study technical analysis is sufficiently formed to allow for meaningful participation and the timing is aligned with our internal consultation steps to optimize study timelines and ensure effective involvement. The first stage where the DPUC can provide input is between Stages 2 and 3 as the engineer works towards the kickoff meeting; however, the consultation is more significant as the engineer gets closer to Plan Development (Stages 5 and 6). The Company coordinates formal meetings with the DPUC as needed throughout the planning stages and at least one formal meeting is held with the DPUC to review Stages 5 and 6 of the area study.

b. The Public Utilities Commission (PUC) does not currently participate in area planning studies.

c. The Office of Energy Resources (OER) does not currently participate in area planning studies but does participate in review and discussion of non-wires alternative opportunities that are identified in Stage 5 of the area study process as part of OER participation in the System Reliability Procurement Technical Working Group and filing process.

d. Other external parties do not currently participate in area planning studies.

Prepared by or under the supervision of: Caitlin Broderick

OER 1-4

Request:

On Bates Page 49, National Grid states "The forecast of peak load incorporates distributed energy resources, or DER's, such as energy efficiency (EE) savings, solar photovoltaics (PV) reductions and electric vehicle (EV) increases achieved through 2019 since these impacts would be reflected in the historical data used by the model."

a. Please provide a link to the complete forecast report, including assumptions, methodology, detailed findings along with uncertainty levels or confidence intervals from the econometric modeling, sensitivity analyses, etc.
b. How does National Grid justify that historical EE, PV, and EV impacts to load are a good proxy for future EE, PV, and EV impacts over the 15-year forecast?
c. How does National Grid account for heating electrification in the load forecast?
d. How does National Grid account for energy storage in the load forecast?
e. How does National Grid consider state policies in the load forecast?
f. What state policies specifically did National Grid include in its current load forecast?

Response:

a. The FY2022 ISR is based on the 2020 forecast due to the schedule. The Company's 2020 peak forecast report, the 2020 Report hereafter, is published on National Grid – Rhode Island System Data Portal, and the direct link to the 2020 Report is provided here: http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2020_Report.pdf
The Company's most recent 2021 peak forecast report, the 2021 Report hereafter, is also available on the same portal:
http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2021_Report_.pdf.

   The overall forecasting methodology is similar between the 2020 forecast release and the 2021 forecast release. The discussions in this response mostly focus on the more recent 2021 Report because it presents the Company's most up-to-date view on the distributed energy resources. The differences between the 2020 method and the 2021 one will also be specified.

   The 2021 Report discusses the following topics and more:

   - Forecasting methodology. The overall methodology is the same between the two releases.

- Weather assumptions. The method to develop weather scenarios is the same and the difference is the definition of most recent twenty years of weather.
- Distributed Energy Resources (DERs). They are energy efficiency (EE), solar photovoltaic (PV), electric vehicles (EV), demand response (DR), and electric heat pumps (EH). The discussions include the projections, scenarios, and impacts. Both 2020 and 2021 releases have EE, PV, and EV. EH was newly introduced in the 2021 Report.
- Climate scenarios were newly introduced in the 2021 Report

The Company addresses the uncertainties in the long-term peak forecasting from the following perspectives, all of which are discussed in the 2021 Report:

- In addition to the normal weather, the Company considers the extreme weather scenarios in the forecast to account for the uncertainties in the weather. Two extreme weather scenarios are included – a 90/10 and a 95/5. The 95/5 extreme weather scenario infers that there is a 5% probability that the weather will be more extreme than this scenario. The Weather Assumption section of the report provides detailed discussions on this.

- Climate change scenario is provided on top of each weather scenario to account for possible changes in the weather over a longer-term. This is provided for informational purposes. The Climate Scenarios section of the report discusses this.

- Base, low, and high scenarios are considered for each DER items to account for different views of their development in the future. Four hundred and thirty-two (432[1]) combined DER scenarios are fed into the forecast to provide additional information on what loads might be under various combinations of DER scenarios. These provide not only the base, maximum and minimum possibilities but all combinations in between to meet the needs of different use cases. Appendix E in the Report discusses the development of these DER scenarios, and the DER Scenarios section in the report presents the results of applying these scenarios to the peak load.

[1] 81 combined scenarios in the 2020 Report

b. The impacts from historically cumulative EE, PV, and EV through 2019 are reflected in the Company's historical load. The Company used a reconstitution method for forecasting: the historical DERs' impacts are first added back/subtracted from historical load to get the reconstituted (i.e., pre-DER) historical load. The reconstituted load is then used in econometric models to predict the future peak prior to the impacts from the DERs. Finally, these peak forecasts are adjusted for future projected DERs' impacts to get the net (i.e., post-DER) peak load forecasts.

   The Company did not use historical DERs' impacts to load as a proxy for the future impacts of DERs. Instead, the Company developed EE, PV, and EV projections and their impacts to load for the next 15 years based on each DER's recent trend and characteristics, recent studies, approved programs, and/or state policy targets as appropriate. The development of the base cases are discussed below and can also be found in the DER Scenarios Development section of the 2021 Report:

   - EE is directly projected as energy savings. Its impact on peak load is then derived from applying the current peak saving to energy saving ratio to the projected energy savings.
     The short-term EE projection is based on the Company's three-year plan target. The projection between 2024 and 2026 is based on the Rhode Island Market Potential Study (MPS)[2] performed by the Dunsky Energy Consulting.
     In the longer-term, the assumption is the rate of annual incremental new EE will decline, which is similar to ISO-New England's assumption. The decline in the rate of new EE reflects declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow, but at a slower rate each year.

   - PV MW to be installed is first projected for the next 15 years. The projection for the future is based on an estimate of installations for units already in the application queue for the first two years, then a continuation of those levels until the year 2023, and then a slowly declining number of new annual installations to account for saturation.

[2] Rhode Island Market Potential Study (2021-2026) https://rieermc.ri.gov/rhode-island-market-potential-study-2021-2026/

The projected PV connected MW is then converted into peak load impact based on a PV generation profile. The profile was developed using the PVWatts Calculator [3] developed and maintained by National Renewable Energy Laboratory (NREL).

- EV adoption is first projected based on Bloomberg's fifth annual Long-term Electric Vehicle Outlook ("BNEF"), dated May 18, 2020. It is a well-known and comprehensive study of the electric vehicle sector, where technology, policy, and economic factors that drive the electric vehicle market were thoroughly studied. The projected number of EVs is then converted to kW impacts to peak load using a profile. The profile was developed from an EV charging study[4] recently conducted by ISO-New England.

c. The Company introduced electric heat pumps into its load forecasting process in the 2020 annual forecasting cycle and discussed it in the 2021 Report. Electric heat pumps were first forecasted as the number of heat pumps to be installed. The base case for the years 2020 to 2029 is based on the ISO-New England estimates. Subsequent to this and through the end of the planning cycle in the year 2035, incremental heat pumps continue to grow, but at a smaller amount each year to reflect saturation.

   The forecasted number of electric heat pumps was then converted to kW impacts to peak load using a profile. It is expected to slightly reduce the summer peak brought by cooling efficiencies. It is expected to add additional load to the winter peak over the next 15 years.

d. The Company assesses implications of energy storage in its forecast but currently does not have energy storage as an individual DER item as the Company does on EE, EV, PV, and DR. This is primarily based on the size of existing storage projects and whether there are established state energy storage policies that can be used to predict future growth.

   The existing storage projects such as PV paired storage and battery projects included in the Company's Demand Response (DR) program have had negligible impacts as compared to the peak.

   There are not established state energy storage policies or other external resources that could be used to predict an impact on our peak load forecast.

[3] PVWatts Version 5 Manual https://www.nrel.gov/docs/fy14osti/62641.pdf
[4] Update on the 2020 Transportation Electrification Forecast by ISO-NE, Nov2019 https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf

The Company actively monitors DER penetration, policies and outlooks and will update the forecasting strategy as appropriate.

e. The Company considers state policies in its DERs projections as appropriate. The projections on DERs are then fed into its load forecast. See discussion above and referenced report on the data portal for information on specific policies used.

f. See discussion above and referenced report on the data portal for information on specific policies used.

OER 1-5

Request:

How was electrification from the non-infrastructure portion of the proposed hybrid solution for gas reliability on Aquidneck Island factored into the load forecast?

Response:

The electrification from the non-infrastructure portion of the proposed hybrid solution for gas reliability on Aquidneck Island has not been factored into the electric load forecast.

OER 1-6

Request:

Regarding the inclusion of the load forecast in the capacity reviews:

a. What is the spatial resolution of the load forecast?
b. How is that load forecast distributed more granularly (e.g. how do you get from a jurisdiction-level load forecast to the load forecasted for each area to the load forecasted specifically for a particular feeder)?
c. How does the load forecast and capacity review consider known or probable changes in load from new customers, new developments, closing businesses, changes in land use or zoning, or other similar information such as can be obtained through statewide and municipal planning and transportation departments?
d. How do the capacity reviews account for specific distributed generation projects with known locations in the interconnection queue?
e. How do the capacity reviews account for probability of project completion for distributed generation projects in the interconnection queue?

Response:

a. The system level peak forecast is provided at two general levels. The first is at the Company (or state) level. The second is at the Planning Supply Area (PSA) level. These PSA's are more granular groupings of load in the state. There are four such areas in Rhode Island (Providence, Newport, Western Narragansett and Blackstone Valley).
b. The overall process for the feeder level forecast starts with a review of the system level projected growth rates in the state. As described in response to (a), the forecast is broken further into four Power Supply Areas (PSA). The PSA growth rates (weather adjustment and economic adjustment) are applied respectively to all feeders in each PSA.
c. The system level peak load forecast does not explicitly take into account specific customer development, business changes or zoning changes. However, as part of the forecasting process, macro-economic factors are used which capture the broader regional level employment and population changes in the market. Capacity reviews consider known or probable changes in load from new customers, new developments and municipal planning information in the form of spot loads as stated in response to OER 1-8. Closed businesses would be incorporated into the peak loads that are the basis for the annual capacity review and does not require further consideration.

Prepared by or under the supervision of: Joseph Gredder and Caitlin Broderick

OER 1-6, page 2

d. It is important to note that peak loading is occurring later in the day with less reduction as a result of Distributer Generation (DG) which creates complexities for capacity reviews. Currently, annual capacity reviews incorporate existing connected DG. Consideration of interconnection queue DG is evolving but is not fully incorporated into the process due to the significant uncertainty about whether a DG project will proceed. The Company is working to consider in queue DG as a reduction to peak loads and its potential ability to defer investments. However, absent express PUC approval, capacity reviews cannot consider the impacts and interconnection costs of future DG projects because of standard ratemaking policy.
e. As stated in response (d), the Company includes currently interconnected DG projects in annual capacity reviews but does not formally incorporate DG projects currently in the interconnection queue at this time. Informally, the Company has considered completion probabilities based on historical trends. For example, projects with an executed Interconnection Service Agreement (ISA) have a 78% chance of completion and projects prior to an executed ISA have a 50% chance of completion.

OER 1-7

Request:

On Bates Page 85, National Grid states "…forecasted growth rates from the base case load forecast are applied to each of the substations and feeders within the area." What justification does National Grid have to support the implied assumption that load growth rates are homogenous across feeders throughout the jurisdiction? If this assumption is a mischaracterization, please clarify the process by which forecasted load growth rates are applied to feeders heterogeneously.

Response:

Prior to the proliferation of Distributed Energy Resource (DER) programs, the Company determined that load growth was relatively homogenous across the Power Supply Areas. For example, air conditioning load was expected to increase consistently across the Power Supply Areas. The Company defined four Power Supply Areas to enable some regional adjustment to expected state economic growth. However, with the significant increase of DER programs, the Company is exploring new forecast modeling techniques, capabilities, and scenarios to enable more precise feeder level forecasting in the future.

OER 1-8

Request:

On Bates Page 85, National Grid states "Distribution planners then adjust forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfiguration." Please elaborate on what qualifies as a "known spot load addition or subtraction," including where this information is sourced.

Response:

A known or anticipated spot load includes but is not limited to new large load customers. The Company is currently considering how to incorporate large DG as spot generators and similarly, consider how to include energy storage which acts as a spot load and a spot generator.

Spot load information can be supplied by numerous sources. Large load customer information is sourced directly from customers through a service request or study request or through engagement with local community officials. Spot generators and batteries are obtained from the application database.

In this manner, the Company can provide feeder level adjustments to the regional forecasts. studies.

Prepared by or under the supervision of: Caitlin Broderick

OER 1-9

Request:

National Grid describes historical peak load data as one input into the load forecast (Bates Page 48). National Grid then describes applying additional inputs about known spot load additions and subtractions (Bates Page 50).

a. Would spot load additions and subtractions be captured implicitly in historical peak load data? Why or why not?
b. If the response to (a) is 'yes': is there a risk of double counting spot load additions and subtractions twice? Why or why not?
c. If the response to (b) is 'yes': what are the consequences of this double counting related to project proposal and selection, and costs?

Response:

a. No, spot loads are for future large customer connections at the feeder level so by definition would not be implicitly captured in historical peak data. By contrast, existing large customer interconnections are captured in historical peak loading. Once spot loads are connected to the system, they are no longer forecasted as a spot load and are captured implicitly in historical peak load data. Spot loads are only added to the forecast in future years as a way to better forecast for known or probable large new customers.

b. No, there is not a risk of double counting spot load additions or subtractions twice. Spot loads are only included in forecasting loads for future years as a way to represent large customers that will be connecting to the system at the feeder level.

c. Not Applicable

Prepared by or under the supervision of: Caitlin Broderick

OER 1-10

Request:

National Grid describes its forecast as using econometric modeling and conducting sensitivity analyses. How were the standard errors and measures of uncertainty from the econometric modeling and the findings from the sensitivity analyses employed in the development of this ISR plan?

Response:

The Company’s forecasting process incorporates econometric models that consider the economy and weather. The Company also adjust the forecasts from the statistical models for estimated impacts from Distributed Energy Resources (DERs), including energy efficiency, solar-photovoltaic, electric vehicles, demand response, and electric heating.

The economic inputs come from Moody’s, a well-known company that provides projections on the economy. The Company uses Moody’s baseline projections and no other scenarios.

The Company does, however, provide multiple scenarios for both weather and DERs to account for uncertainties. For weather, a base case (50/50) and two extreme scenarios (a 90/10 and a 95/5) are provided. For DERs, a base case, and higher and lower scenarios are considered. The base scenario is the one with the highest likelihood and Distribution Planning utilizes the base DER scenario for annual planning analysis

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OER 1-11

Request:

Has National Grid forecasted hosting capacity?

a. If so, how was the hosting capacity forecast used in the development of this ISR plan?
b. If not, why not?

Response:

The Company has not forecasted hosting capacity; however, hosting capacity information is provided considering the Distributed Energy Resources (DER) in queue on the Rhode Island Data portal website. Hosting capacity information is intended to be used by developers to encourage them to apply for DER projects in areas where hosting capacity opportunities exist.

The Company does not need forecasted hosting capacity information to perform its Area Planning Studies and therefore forecasted hosting capacity is not used in development of the ISR plan. The ISR plan consists of work to maintain safe, reliable and efficient electric service for all customers, which is not dependent upon existing opportunities for locating DER.

If the Company were to fully forecast hosting capacity that would likely result in much less or no hosting capacity opportunity in many or most areas. Attempting to fully forecast hosting capacity would involve making a variety of assumptions that might create significant confusion around existing hosting capacity opportunities.

Prepared by or under the supervision of: Caitlin Broderick

OER 1-12

Request:

On Bates Page 50, National Grid states "Individual project proposals are identified to address imminent planning criteria violations." On Bates Page 51, National Grid states "In addition to identifying imminent issues and corresponding small-scale solutions…" On what timescale is a violation or an issue considered "imminent"? (e.g. this year, the next five years, the 15-year forecasting horizon)

Response:

An imminent issue could be considered an issue projected to occur within the next one to two years.

OER 1-13

Request:

Regarding Chart 6 on Bates Page 56: when were the previous completed dates for areas ranked 5A through 10?

Response:

Area Planning Studies as they are performed today have not previously been completed on areas ranked 5A through 10. The first Area Planning Study completed in 2015 using the current area study process. Planning analysis and area studies occurred in the past but not in the area study territory and manner as is the currently performed.

OER 1-14

Request:

What is/are the threshold criterion/a for a small-scale project (such as one that addresses "imminent issues"; Bates Page 50) and a large project (such as is referenced in Chart 7 on Bates Page 58)?

Response:

There is no specific dollar threshold for small- scale projects versus large projects. A general refence point currently used for small scale projects often relates to projects estimated to cost up to approximately $500,000.

Prepared by or under the supervision of: Caitlin Broderick

OER 1-15

Request:

What factors drive whether an asset at the end of its life (e.g. an asset in the asset condition category) gets replaced with a same-sized new asset or a different-sized new asset? Explanation through an example would be satisfactory.

Response:

There are a variety of factors that drive whether an asset at the end of its life gets replaced with a same sized asset or a different-sized new asset. Within area planning studies, asset condition issues are considered with loading, reliability and other issues in a comprehensive manner. The solution to the combination of issues could be replacing an asset at the end of its life with a larger or smaller unit.

For example, if a 20MVA substation transformer is being replaced due to asset condition but other planning study results may require rebuilding the station with two 55MVA transformers, the Company would replace the 20MVA transformer with a 55MVA transformer to align with the overall area requirements.

Additionally, all new projects must be designed and constructed to the Company's latest standards. It is possible that the asset being replaced no longer meets the latest Company standards and a different-sized asset is installed to align with the latest standard requirements. For example, if the Company is designing a distribution line project that is addressing asset condition issues, the Company will design the project to new standards which could include going from 40-foot poles to 45-foot poles.

OER 1-16

Request:

For projects involving reconductoring or upsizing equipment for either customer requests or system capacity:

a. What is the total number of such projects included in this plan?
b. What is the number of such projects that will be replacing a piece of equipment before its end of life?
c. For the number of such projects given in response to (b), what is the average number of years the equipment is replaced before end of life?
d. For the number of such projects given in response to (b), what is the aggregate total of non-equipment costs, such as the cost of labor, cost of police duty, etc.?
e. What does National Grid do with equipment that is replaced before end of life?
f. How are ratepayers credited for equipment taken out of service before end of life?

Response:

a-d. There could be a variety of projects in the plan that include reconductoring or upsizing equipment for customer requests or system capacity. Often the equipment that is reconductored or upsized can be subpart of larger project scopes. The Company does not categorize or track the components of a project in a manner that has the data needed for this request available.

For example, the Aquidneck Island Projects include overhead line reconductoring along certain streets to establish new feeder routes and convert 4kV areas to 15kV. Whether the reconductoring results in upsizing would require a pole to pole review of the project design. In addition, reconductoring can also enable the retirement of other assets, where the overall system capacity remains largely unchanged. Therefore, a comprehensive review of the project design and scope would have to be undertaken for every customer request or system capacity project in the plan to identify the projects that qualify to be included in the response to 1-16 a. as this subset of specific project data is not currently being tracked.

Whether equipment is at or before its end of life, determining the average number of years the equipment is replaced before end of life, and providing the associated individual cost components would require an individual asset review within the pole to pole and scope review noted in the previous paragraph. As noted above, this data is not currently being tracked to be able to respond to 1-16 b, c, and d.[i]

Prepared by or under the supervision of: Caitlin Broderick & Melissa Little

e. As a general practice, National Grid salvages or reuses any equipment that is replaced before end of life.

f. The Company follows general utility practices for the depreciation of plant assets. Assets that are similar in nature and have approximately the same useful lives such as poles and wires are depreciated by group. Assets in this group are considered mass plant where we have a very high volume of installs/retires. If there are specific assets that needs to be retired early, the cost in the Plant in Service gets transferred to Accumulated Reserve for Depreciation. Any difference between the original book cost and the accumulated depreciation will remain in the Accumulated Reserve for Depreciation account. There will be no gain or loss since any over and under depreciation of these retired assets should balance out.

While retirements do not impact net plant as discussed above, retirements do impact depreciation expense. In the Company's annual ISR revenue requirement calculations, incremental capital eligible for inclusion in ISR rate base is reduced by the amount of actual plant retirements or an amount of plant retirements projected to occur during the fiscal year to arrive at net depreciable ISR plant. Incremental depreciation expense recoverable through the ISR is calculated on this net depreciable ISR plant, therefore crediting customers for depreciation expense included in distribution base rates on plant that has since been retired.

[i] After discussions with OER, the parties agreed that providing actual numbers in response to subsections (a) through (d) was not necessary.

OER 1-17

Request:

Please provide annual SAIDI and SAIFI statistics (both excluding and including major event days) for 2010 through latest year for each of the 38 municipalities National Grid serves.

Response:

The tables below contain the annual SAIDI and SAIFI statistics for 2010 through 2020 for each of the 38 municipalities served by National Grid in Rhode Island.

Tables 1 and 2 exclude major event days, and tables 3 and 4 include major event days. Please note that the totals in these tables will not match the Company totals. Municipality level data is estimated since the reliability data captured in the company's reliability reporting system, Interruption and Disturbance System (IDS), is not identified specifically to each municipality.

OER 1-17, page 2

1. Excluding Major Storms

Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BARRINGTON	1.818	2.324	0.957	1.581	0.777	1.931	0.594	1.636	1.524	1.965	1.381
BRISTOL	0.91	0.379	0.675	0.499	0.31	0.685	0.865	1.312	0.242	2.024	0.38
BURRILLVILLE	1.115	1.917	2.915	1.284	1.56	0.339	1.919	0.482	1.409	2.695	1.916
CENTRAL FALLS	0.237	0.925	0.207	0.922	1.004	0.996	0.858	0.899	1.465	1.299	1.364
CHARLESTOWN	1.376	1.981	1.774	0.516	1.377	0.699	1.854	1.244	0.898	1.558	1.174
COVENTRY	0.747	1.537	0.985	1.881	0.76	0.864	1.025	1.048	1.148	1.733	1.091
CRANSTON	0.96	0.547	0.88	0.558	0.451	0.256	0.777	0.431	1.242	0.341	0.509
CUMBERLAND	1.24	1.434	1.207	1.244	1.042	1.048	1.431	1.33	1.498	1.761	1.509
EAST GREENWICH	1.451	0.746	0.627	1.031	1.038	0.58	0.314	0.728	1.031	1.448	0.874
EAST PROVIDENCE	1.179	0.464	0.556	0.321	0.253	0.989	0.374	0.355	1.011	0.443	0.432
EXETER	1.472	1.357	1.499	1.85	1.497	2.02	1.947	1.573	2.251	4.293	3.807
FOSTER	2.52	3.473	1.707	0.889	0.328	0.484	1.171	1.479	1.777	3.045	1.614
GLOCESTER	2.81	2.514	2.386	1.583	0.683	0.9	2.556	1.801	3.295	2.514	2.573
HOPKINTON	2.679	1.148	1.924	0.637	0.234	1.034	1.396	0.966	2.689	2.09	1.695
JAMESTOWN	2.29	1.049	0.825	1.162	1.111	0.608	1.089	1.491	1.084	0.163	1.572
JOHNSTON	1.07	0.62	1.256	0.562	0.539	0.656	1.442	0.218	0.957	1.07	1.281
LINCOLN	1.095	1.362	1.183	0.937	0.501	1.138	1.259	1.239	1.676	2.632	1.62
LITTLE COMPTON	0.83	1.907	0.307	1.656	1.413	1.885	4.208	2.38	1.253	3.436	1.189
MIDDLETOWN	0.604	0.755	0.878	0.853	0.981	1.088	1.258	0.228	0.618	0.983	1.654
NARRAGANSETT	1.399	1.162	0.753	0.578	0.853	0.562	1.071	0.994	0.992	0.497	0.867
NEWPORT	0.969	0.757	0.805	0.578	0.979	0.964	0.707	0.32	0.984	1.25	1.137
NORTH KINGSTOWN	1.008	0.779	0.59	0.725	1.116	0.909	0.53	1.895	1.165	0.715	0.799
NORTH PROVIDENCE	0.499	0.521	0.518	0.45	0.972	0.389	1.034	0.548	0.787	0.321	1.609
NORTH SMITHFIELD	1.054	1.717	3.228	1.008	1.739	0.988	2.049	0.912	1.356	2.223	1.909
PAWTUCKET	0.798	0.765	0.486	0.432	0.514	1.322	0.59	0.905	1.458	1.053	1.313
PORTSMOUTH	1.184	2.497	0.195	1.295	2.598	1.175	1.02	0.402	0.237	1.947	0.591
PROVIDENCE	0.395	0.326	0.544	0.38	0.473	0.404	0.741	0.471	0.502	0.435	0.502
RICHMOND	1.115	1.029	1.664	0.735	0.689	0.949	1.353	0.826	1.876	2.065	1.799

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCITUATE	1.258	1.653	2.072	1.763	0.92	0.697	1.367	2.244	1.201	1.702	1.39
SMITHFIELD	1.04	0.926	0.329	0.461	0.318	0.313	0.685	0.665	0.992	0.458	0.964
SOUTH KINGSTOWN	1.769	1.092	0.773	0.635	1.815	0.526	1.416	0.933	0.81	0.76	1.044
TIVERTON	1.618	1.199	0.451	0.288	0.617	2.38	0.883	0.901	0.445	1.51	0.551
WARREN	0.755	0.761	1.711	0.566	0.179	1.507	0.076	0.799	1.14	2.573	0.35
WARWICK	1.695	0.766	0.494	0.631	0.419	1.534	0.719	0.482	0.444	0.402	0.375
WEST GREENWICH	0.401	3.34	2.224	0.583	0.373	0.465	0.735	0.688	0.865	2.115	1.363
WEST WARWICK	0.905	0.344	0.724	0.815	0.785	0.777	0.615	0.451	0.751	0.59	0.242
WESTERLY	1.863	1.548	2.962	0.685	1.266	1.389	2.08	0.68	1.742	1.589	1.722
WOONSOCKET	0.788	0.802	1.132	0.867	1.266	1.152	1.147	1.01	1.137	0.769	0.917

Table 1: SAIFI - Excluding Major Event Days

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BARRINGTON	132.99	156.95	93.93	99.87	53.83	219.70	39.14	131.36	125.59	76.85	165.62
BRISTOL	52.98	21.59	111.28	50.57	44.80	55.61	73.00	84.91	17.69	75.77	35.50
BURRILLVILLE	105.07	174.19	132.31	77.80	43.59	37.28	163.19	66.27	131.91	228.66	199.66
CENTRAL FALLS	13.73	84.04	11.87	55.28	50.18	57.65	34.32	36.83	77.88	103.85	149.84
CHARLESTOWN	79.74	180.44	149.50	86.66	100.46	88.99	109.26	162.13	86.84	103.64	103.24
COVENTRY	88.16	108.52	86.54	174.37	67.13	67.69	100.22	92.01	110.17	79.11	108.12
CRANSTON	71.27	45.25	54.57	35.33	31.68	19.40	57.66	45.18	66.29	22.15	30.55
CUMBERLAND	46.03	86.11	79.79	67.18	48.89	75.08	65.32	58.51	69.25	82.77	69.39
EAST GREENWICH	74.49	75.34	33.31	64.02	90.07	63.66	45.01	56.79	89.18	92.34	86.59
EAST PROVIDENCE	91.16	26.58	46.20	21.19	22.42	58.95	20.26	23.45	57.98	20.51	34.17
EXETER	114.20	278.50	80.68	227.98	130.00	214.40	155.55	140.56	186.51	390.32	280.81
FOSTER	199.64	474.60	225.52	144.71	57.05	66.19	311.36	267.19	211.06	295.33	243.41
GLOCESTER	183.24	142.94	191.72	103.60	87.63	83.49	209.90	188.94	267.06	285.45	222.13
HOPKINTON	223.39	146.15	194.42	159.14	27.88	153.50	52.71	134.75	267.62	243.08	158.10
JAMESTOWN	156.04	34.61	69.29	113.30	98.39	45.55	96.27	110.91	46.35	12.53	127.45
JOHNSTON	80.85	48.67	90.91	31.17	36.56	44.07	91.82	22.52	65.71	62.39	75.41
LINCOLN	87.68	57.64	53.54	77.95	33.75	69.39	55.31	79.73	111.58	141.34	125.52
LITTLE COMPTON	164.90	115.29	35.17	183.75	119.49	141.48	517.43	144.79	108.95	180.81	90.41
MIDDLETOWN	50.96	35.97	34.47	57.23	54.70	38.87	42.80	16.00	28.47	49.93	182.66
NARRAGANSETT	87.35	98.24	93.01	29.50	72.47	72.92	42.05	62.89	89.18	42.36	65.62
NEWPORT	52.82	49.82	36.36	39.94	33.79	35.29	40.87	13.89	74.39	35.91	59.90
NORTH KINGSTOWN	87.25	73.37	61.56	89.38	79.18	64.26	55.31	133.57	68.99	58.18	48.00
NORTH PROVIDENCE	22.98	31.05	35.08	24.93	65.16	24.29	48.84	42.18	42.05	29.29	114.00
NORTH SMITHFIELD	83.48	121.60	118.61	51.67	68.04	61.81	175.40	64.75	96.12	133.69	122.06
PAWTUCKET	49.81	37.98	47.82	19.48	27.45	79.60	37.83	60.81	80.03	65.20	65.72
PORTSMOUTH	116.52	87.99	27.40	91.02	184.84	53.71	50.60	25.98	27.93	98.20	54.18
PROVIDENCE	24.54	25.58	32.86	29.55	42.89	34.15	44.90	35.30	35.65	37.43	30.39
RICHMOND	114.33	141.70	193.15	86.59	84.06	65.33	43.37	69.02	242.29	174.23	112.92
SCITUATE	100.61	124.22	109.29	172.16	69.34	76.58	142.91	236.58	99.71	159.00	135.56

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SMITHFIELD	65.72	70.30	47.12	26.36	18.61	24.95	75.44	42.44	66.37	77.46	85.90
SOUTH KINGSTOWN	118.82	102.99	78.76	85.99	163.39	40.76	60.80	67.87	65.52	54.45	102.63
TIVERTON	135.58	73.72	19.53	37.76	35.56	191.84	92.95	74.11	32.03	64.17	40.40
WARREN	52.02	52.87	161.74	74.37	10.35	85.97	9.20	62.90	73.29	269.55	36.21
WARWICK	119.06	57.88	39.26	45.95	38.10	85.67	61.52	43.93	31.15	39.32	33.12
WEST GREENWICH	40.64	301.10	84.01	177.47	31.82	95.63	41.28	94.64	90.15	223.65	137.27
WEST WARWICK	73.71	24.89	53.72	72.18	50.96	55.10	74.30	31.10	59.30	50.53	21.02
WESTERLY	142.53	111.73	170.88	41.29	91.12	123.62	126.95	93.97	54.18	97.23	100.24
WOONSOCKET	41.35	45.40	60.52	48.15	50.97	89.25	81.64	68.25	58.07	42.46	49.56

Table 2: SAIDI - Excluding Major Event Days

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2. Including Major Event Days

Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BARRINGTON	1.819	3.615	1.322	2.511	0.777	2.381	0.664	2.243	3.213	3.438	3.877
BRISTOL	0.910	1.223	1.275	1.447	0.310	0.814	1.167	2.096	1.348	3.328	0.662
BURRILLVILLE	1.115	3.439	3.133	1.366	1.560	0.339	3.510	0.941	2.641	3.340	4.382
CENTRAL FALLS	0.241	1.723	0.677	1.729	1.004	0.996	0.921	1.083	2.243	1.813	2.140
CHARLESTOWN	2.218	3.994	2.759	1.315	1.377	1.519	1.941	2.202	1.944	2.140	1.970
COVENTRY	0.748	2.829	1.382	2.165	0.760	1.323	2.052	1.478	1.668	2.099	2.487
CRANSTON	1.113	1.129	1.002	1.015	0.451	0.884	0.780	0.595	1.712	0.580	1.343
CUMBERLAND	1.254	2.820	1.917	1.953	1.042	1.048	1.885	1.577	2.247	2.214	2.612
EAST GREENWICH	1.498	2.068	1.328	1.535	1.038	0.927	0.486	1.413	2.115	1.769	1.458
EAST PROVIDENCE	1.181	1.056	1.100	1.126	0.253	1.421	0.613	0.601	1.647	0.578	1.308
EXETER	1.474	3.197	2.440	2.470	1.497	2.094	2.659	3.057	4.161	5.683	5.550
FOSTER	2.631	4.919	2.850	0.919	0.328	0.495	1.487	2.412	3.127	5.401	2.864
GLOCESTER	2.824	4.266	3.675	1.937	0.683	0.909	3.280	2.668	4.879	3.834	4.950
HOPKINTON	2.853	2.120	2.664	1.209	0.234	1.044	1.931	1.778	4.296	3.096	2.631
JAMESTOWN	3.282	3.245	1.705	3.066	1.111	0.608	1.137	1.977	1.337	0.751	1.675
JOHNSTON	1.072	1.708	1.404	0.730	0.539	0.763	1.514	0.519	1.315	1.316	1.721
LINCOLN	1.096	2.930	1.635	1.332	0.501	1.166	1.900	1.884	2.443	3.138	3.309
LITTLE COMPTON	1.376	3.857	2.079	2.997	1.413	2.086	4.791	3.267	2.192	4.065	3.085
MIDDLETOWN	0.789	1.960	1.621	2.847	0.981	1.090	1.260	0.265	0.904	0.999	2.638
NARRAGANSETT	1.946	2.534	1.693	1.514	0.853	1.245	1.473	1.233	1.574	1.496	1.760
NEWPORT	0.999	1.892	1.426	2.491	0.979	0.964	0.726	0.347	1.252	1.259	1.792
NORTH KINGSTOWN	1.071	1.707	1.037	1.275	1.116	1.027	0.905	2.630	2.205	1.133	1.157
NORTH PROVIDENCE	0.499	1.289	0.564	0.747	0.972	0.390	1.074	0.969	1.254	0.471	2.092
NORTH SMITHFIELD	1.072	3.936	3.411	1.101	1.739	0.988	2.465	1.674	2.050	3.069	3.638
PAWTUCKET	0.798	1.455	0.515	0.853	0.514	1.441	0.874	1.115	1.742	1.316	1.834
PORTSMOUTH	1.196	3.936	0.634	4.056	2.598	1.176	1.031	1.337	0.552	1.990	0.841
PROVIDENCE	0.403	0.654	0.565	0.512	0.473	0.524	0.804	0.612	0.681	0.461	0.716
RICHMOND	1.126	1.553	2.754	1.031	0.689	0.972	1.734	1.509	3.292	2.899	3.364

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCITUATE	1.266	3.008	2.817	1.943	0.920	0.957	2.082	3.151	2.493	2.358	2.857
SMITHFIELD	1.047	1.596	0.621	0.623	0.318	0.319	0.840	0.998	1.251	0.612	1.251
SOUTH KINGSTOWN	1.876	1.826	1.433	1.239	1.815	1.333	1.547	1.451	1.407	1.091	1.506
TIVERTON	1.781	2.614	1.756	1.228	0.617	2.534	1.454	0.979	0.946	1.578	0.930
WARREN	0.755	1.700	2.223	1.570	0.179	1.541	0.166	1.017	1.816	3.718	0.576
WARWICK	1.753	1.872	0.869	0.830	0.419	2.289	0.777	0.836	0.794	0.483	0.623
WEST GREENWICH	0.402	4.413	2.854	0.699	0.373	0.486	1.940	1.758	1.548	3.016	2.927
WEST WARWICK	1.072	1.598	0.903	0.853	0.785	1.448	1.066	0.946	1.323	0.678	0.685
WESTERLY	2.494	1.964	4.014	1.129	1.266	1.647	2.118	1.048	2.726	2.583	2.086
WOONSOCKET	0.821	1.455	1.212	1.172	1.266	1.182	1.180	1.385	1.373	0.953	1.744

Table 3: SAIFI - Including Major Event Days

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
BARRINGTON	133.00	3,977.67	294.49	2,351.77	53.83	659.89	92.80	1,223.52	2,369.06	341.27	1,634.26
BRISTOL	53.02	3,087.71	524.06	2,395.10	44.80	90.18	211.71	1,296.84	1,311.61	369.59	119.29
BURRILLVILLE	105.07	4,598.97	375.93	117.33	43.59	37.28	1,382.63	1,493.17	1,156.97	515.05	1,729.69
CENTRAL FALLS	13.76	2,847.52	170.33	694.16	50.18	57.65	52.66	300.22	1,079.38	309.37	528.25
CHARLESTOWN	265.24	6,077.42	4,401.51	3,115.39	100.46	1,346.04	201.31	2,111.10	1,392.19	752.12	1,112.95
COVENTRY	88.81	2,094.82	805.61	301.29	67.13	540.63	584.17	1,021.10	898.51	384.32	1,045.15
CRANSTON	214.83	1,121.54	115.76	392.93	31.68	592.08	59.62	257.72	351.23	83.43	552.39
CUMBERLAND	47.71	2,930.70	163.66	393.20	48.89	75.08	178.04	584.54	599.13	174.98	878.38
EAST GREENWICH	77.32	2,278.02	1,184.38	935.99	90.07	402.98	173.20	622.12	1,577.52	312.64	512.76
EAST PROVIDENCE	98.49	900.13	187.09	1,090.90	22.42	283.12	56.56	244.82	394.52	48.51	685.38
EXETER	116.01	7,392.54	2,720.80	1,488.30	130.00	227.63	1,017.43	2,590.46	2,826.75	1,615.18	1,871.20
FOSTER	217.81	9,841.44	2,634.93	167.28	57.05	75.15	549.28	2,699.52	2,006.00	1,029.07	1,779.62
GLOCESTER	185.78	6,818.03	1,965.70	247.99	87.63	89.46	1,009.93	2,914.34	2,055.46	1,007.47	2,078.59
HOPKINTON	226.37	3,579.06	2,505.17	1,869.02	27.88	164.95	469.19	2,736.02	3,116.18	1,386.67	1,064.98
JAMESTOWN	264.11	2,160.88	1,451.85	2,314.58	98.39	45.55	117.43	366.00	278.50	333.16	188.66
JOHNSTON	81.10	1,566.47	250.23	270.48	36.56	118.96	129.37	531.07	590.56	168.14	463.44
LINCOLN	87.75	2,103.84	242.57	276.02	33.75	72.67	153.56	1,070.68	564.68	287.76	1,202.99
LITTLE COMPTON	247.37	2,406.85	2,405.45	4,371.04	119.49	188.09	989.92	723.66	667.39	355.06	526.51
MIDDLETOWN	96.16	1,620.07	966.87	1,498.02	54.70	39.53	42.85	36.74	114.52	60.30	514.38
NARRAGANSETT	203.16	2,112.99	3,037.59	2,181.52	72.47	152.65	221.49	465.77	742.32	521.42	378.84
NEWPORT	62.81	1,827.39	519.71	1,700.47	33.79	35.32	43.72	36.99	176.30	52.02	200.88
NORTH KINGSTOWN	100.92	2,433.00	977.24	1,614.11	79.18	169.29	172.22	1,139.50	877.55	296.90	282.53
NORTH PROVIDENCE	22.98	989.22	61.05	431.49	65.16	27.01	51.54	706.55	426.00	42.98	394.99
NORTH SMITHFIELD	85.22	3,313.30	392.19	91.04	68.04	61.89	435.80	1,641.70	447.40	368.25	1,646.46
PAWTUCKET	49.81	2,119.58	81.39	224.56	27.45	100.14	76.47	371.90	315.74	171.17	271.89
PORTSMOUTH	118.98	2,982.41	572.14	1,318.95	184.84	53.81	52.32	220.87	112.90	138.69	107.21
PROVIDENCE	45.45	454.46	53.62	147.62	42.89	99.00	51.85	228.84	127.06	42.03	185.64
RICHMOND	121.65	3,232.25	2,793.76	1,112.56	84.06	89.55	208.41	2,097.80	2,351.40	1,307.82	1,476.42
SCITUATE	101.25	5,886.17	959.60	347.29	69.34	304.98	544.21	2,422.25	1,436.06	497.72	1,692.07

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Town	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SMITHFIELD	66.83	1,503.92	132.63	86.26	18.61	27.51	107.14	1,027.99	359.24	113.68	462.97
SOUTH KINGSTOWN	148.68	2,576.37	2,772.99	1,955.84	163.39	251.95	121.37	1,137.82	738.49	354.29	606.98
TIVERTON	157.67	793.89	1,743.19	1,790.44	35.56	229.57	182.28	148.40	284.11	105.85	123.90
WARREN	52.02	2,109.31	377.05	2,428.76	10.35	121.44	37.03	336.31	424.59	506.56	225.71
WARWICK	288.82	1,957.92	501.36	420.10	38.10	1,268.52	81.22	852.21	346.60	79.77	166.26
WEST GREENWICH	40.80	4,187.59	964.76	378.08	31.82	111.99	769.90	1,541.93	1,476.67	519.88	1,198.68
WEST WARWICK	257.13	1,670.56	348.48	159.09	50.96	917.68	165.95	761.64	695.94	75.74	324.07
WESTERLY	780.94	801.24	2,429.83	964.83	91.12	506.57	139.57	674.08	824.08	914.00	269.18
WOONSOCKET	49.42	922.85	91.07	105.56	50.97	104.40	92.32	321.59	86.37	47.38	371.52

Table 4: SAIDI - Including Major Event Days

OER 1-18

Request:

Please describe the interconnection system upgrade study process for a typical standard solar PV application in relation to days following receipt of the necessary data to run such a study. An example response may look like:

Days since complete data/application received	Activity
0	Data/application received in full
1 through k	Activity 1
…	…
T-k through T	Activity N

a. How long does an individual study take to run on the software used? A range of time is an acceptable response. Please exclude the time needed to enter data, quality check or validate the model, etc.
b. What factors influence the amount of time the interconnection system upgrade study process takes?
c. For each category of interconnection application, what is the average probability that a given project will be completed? Please use actual interconnection data in developing your response and describe the methods used to calculate probabilities.
d. Please provide a definition for each status type that can be assigned to projects in the interconnection queue.

Response:

Below is an approximate outline of study timing for a typical standalone solar System Impact Study. The table indicates approximate business days required to accomplish the core activities related to System Impact Studies, however they are not specifically prescribed days allocated to each task. Depending on the complexity of the design in the proposed application, and the electrical characteristics of the are utility system, certain tasks may take longer than others. The tariff currently mandates a total of 55 Business Days (BD) for completion of study activities, to which the company adheres, followed by a 15 BD mandate for delivery of Interconnection Service Agreement.

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Business Days since complete data/application received	Activity
0	Customer documentation received and System Impact Study processed
1 - 20	Primary assessment of system impacts reviewing customer documentation, area distribution feeders & substation capacity, risk of islanding analyses, high level voltage stability assessment
20	Advise customer of any results of the primary assessment that are likely to result in the need for high cost and/or high complexity distribution system modifications.
20 - 35	Assembly of system models for load flow and protective device analyses. Incorporation of the subject applicant's proposed DG. Verification and incorporation of existing and in process DG prior in queue into the models.
35 - 45	Development of required system modifications based on modeling results. Coordinating with other internal groups to confirm feasibility and details, as needed.
45 – 50	Prepare report document summarizing results of the engineering analysis, indication of required system modifications, indication of required customer document corrections. Process draft report for internal QC review.
50	Provide draft report to customer, requesting that customer address the required customer document updates.
HOLD	Application is put on hold while the customer addressed the required document corrections and/or clarifications.
50 - 55	Once updated customer documents are received, the report is finalized and provided to the customer.
55 – 70	Within 15 BD of delivering the system impact study, the Company delivers an Interconnection Service Agreement

Prepared by or under the supervision of: Michael Porcaro

a. Within each System Impact Study (SIS) there is a modeling software used for load flow analyses and a separate software used for protective device analysis. For projects interconnecting to more complex areas of the service territory, for instance those that contain looped systems or sub-transmission interconnections, additional dynamic load flow analysis software is required. For an individual SIS, several models within each software package are created to reflect various system states such as peak and minimum load. Though time to run the software is minutes, building the model with the correct inputs can take a significant amount of time. Also, the model may be run 15-20 times in the course of analysis, as various system modifications are tested to determine the best fit solution to accommodate the proposed Facility. In addition, data validation alone requires that the model be run several times to confirm accuracy in the model components.

b. Factors affecting the amount of time a SIS takes include:
    - Complexity of the Customer's proposed design
        - Quantity of service transformers
        - Energy storage operating schedules
        - Relaying and protection design
        - Site size? And location?
    - Review and comment on Customer document deficiencies
        - Requesting absent documentation
        - Identifying documentation that does not comply with Company standards as published in ESB 756
    - Electrical characteristics of the area Company system
        - Distance from the substation
        - Line loading conditions
        - Protective device coordination
    - Area Analysis
        - Complex customer designs and/or complex Company system conditions lead to increased time for accurate modeling and area analysis
    - System modification solution development
        - Physical routing/locating/planning for new infrastructure such as new feeders, new substations, or substation expansions
        - Development of cost estimates to tariff required accuracy levels

- Customer design changes
  - Modification of customer design elements during the SIS process, requiring revision or altogether restart of engineering modeling and analysis

c. In looking at Complex applications that have completed System Impact Study since 2015, the Company has the following data:

Complex Apps that Completed System Impact Study				
Status	**Applications**		**Generation Capacity**	
	Qty	**% of Total**	**MW**	**% of Total**
Connected	113	49%	212.441	49%
Withdrawn	116	51%	219.108	51%
Grand Total	**229**		**431.55**	

In looking at Simplified applications received since 2015, the Company has the following data:

Simplified Applications				
Status	**Applications**		**Generation Capacity**	
	Qty	**% of Total**	**MW**	**% of Total**
Connected	9042	88%	53.544	90%
Withdrawn	1216	12%	5.985	10%
Grand Total	**10258**		**59.529**	

Results show a higher withdrawal rate for larger Complex projects than Simplified.

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d. The following summarizes definitions for each status type that can be assigned to projects in the Company's online application portal.
    1. **Preapplication**: Customer request to obtain pre-application report in accordance with RIPUC 2180 Section 3.2. Includes Customer initiation of request through delivery of pre-application report by the Company.
    2. **Application**: Customer submission of application via appropriate tariff path in accordance with RIPUC 2180 Section 3. Includes Customer submission through application deemed complete by the Company.
    3. **Screening**: Initial review conducted by the Company in accordance with RIPUC 2180 Section 3 and Figure 1. Includes time from application deemed complete through delivery of screening memo to Customer.
    4. **Preliminary Study**: Company performance of Feasibility Study in accordance with RIPUC 2180 Section 3. Includes time from Company issuance of Feasibility Study agreement through delivery of Feasibility Study report. Note that not all applications undergo Feasibility Study, as identified in RIPUC 2180.
    5. **Supplemental Review**: Company performance of Supplemental Review in accordance with RIPUC 2180 Section 3. Includes time from Company issuance of Supplemental Review agreement through delivery of Supplemental Review report. Note that not all applications undergo Supplemental Review, as identified in RIPUC 2180.
    6. **Study**: Company performance of System Impact Study in accordance with RIPUC 2180 Section 3.4. Includes time from Company issuance of System Impact Study agreement through delivery of System Impact Study report.
    7. **Detailed Study**: Company performance of Detailed Study in accordance with RIPUC 2180 Section 3.4. Includes time from Company issuance of Detailed Study agreement through delivery of Detailed Study report. Note that not all applications undergo Detailed Study, as identified in RIPUC 2180.
    8. **Conditional Approval**: Company delivery of Interconnection Service Agreement, agreement execution, and Customer payment. Includes time from drafting of ISA through execution and processing of Customer initial 25% CIAC payment.
    9. **Design**: Company performance of design activities associated with the System Modifications identified in the System Impact Study. Includes time following receipt and processing of Customer initial 25% CIAC payment through design completion.
    10. **Construction**: Company performance of construction related activities associated with the System Modifications identified in the System Impact Study and further developed within the Design phase. Includes time following receipt and processing of Customer's second CIAC payment of 75% through construction completion.
    11. **Witness Test**: Coordination of Customer provided Witness Test documentation, review of documentation by the Company, and performance of Witness Test in

accordance with RIPUC 2180 Section 3. Includes time from Customer submission of Witness Test documentation through final approval of Witness Test results.

12. **Completion Documents**: Customer completion documents submitted to the Company for review and approval. Includes time after construction completion when customer submits required documentation through approval of documentation.
13. **Meter Installation**: Company installation of the meter at the Customer site. Includes time from completion document approval through scheduling and installation of meter.
14. **Connected**: Finalization steps for the Company to provide Authority to Interconnect to the Customer including asset registration, bill verification, and record updates. Upon successful issuance of Authority to Interconnect, the application remains in the Company system as "Connected".
15. **Change Review**: Customer proposed changes to the application, requiring Company review. A restudy of the project may be required as a result. The application goes on Hold status until the change review is complete and any associated restudy efforts are complete. The Change Review status can happen at any stage of the interconnection process.
16. **Hold**: In accordance with applicable sections of RIPUC 2180, process point where business days counting against tariff timelines are paused due to Customer changes, outstanding Customer obligations, Affected System Operator studies, or other similar outside/3rd party influences beyond the control of the Company. Holds can occur at any stage of the interconnection process. Rationale for hold is identified by the Company.
17. **Pending Withdraw**: Cure period generally associated with Customer non-compliance with outstanding obligation. Rationale for withdrawal is posted to the portal for Customer awareness. Reasons for withdraw as permitted and identified within RIPUC 2180.
18. **Withdrawn**: Application withdrawn from the process at the election of the Customer or as a result of non-compliance with process obligation. Rational for withdrawal is posted to the portal for Customer awareness. Reasons for withdraw as permitted and identified within RIPUC 2180.
19. **Terminated**: Application has achieved interconnection and Customer later decides to decommission and disconnect the project.

OER 1-20

Request:

What time horizon does National Grid plan for when determining system modifications and system improvements for interconnecting DER?

Response:

System modifications and system improvements for interconnecting DER are determined during the DER interconnection study, and there are mandated construction schedule requirements per the Rhode Island Interconnection Tariff. The construction timelines vary between 270 to 360 calendar days and can sometimes be adjusted further to a mutually agreed upon schedule.