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March 24, 2023

VIA ELECTRONIC MAIL AND HAND DELIVERY

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

Re: The Narragansett Electric Company d/b/a Rhode Island Energy
In Re: Advanced Meter Functionality Business Case – Docket No. 22-49-EL

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), attached is the electronic version of Rhode Island Energy's responses to the Public Utilities Commission's Fifth Set of Data Requests in the above-referenced matter, specifically PUC 5-2, PUC 5-8, PUC 5-9, PUC 5-11, PUC 5-14, PUC 5-15, PUC 5-16, PUC 5-17, PUC 5-19, PUC 5-20, PUC 5-21, PUC 5-25 and PUC 5-26.[1]

Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Adam M. Ramos

AMR:cw
Enclosures

cc: Service List 22-49-EL (via e-mail only)
John Bell, Division
Leo Wold, Esq.

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

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 24th day of March, 2023.

____
Adam M. Ramos, Esq.

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 2/27/2023

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PUC 5-2

Request:

Do all customers, even customers that call in outages, automatically receive outage notifications in the Pennsylvania territory now that AMI outage notification has been enabled? If so, please explain how customers receive these automatic notifications, the exact messages they receive today and, if known, the message they received during the 2019 to 2020 study period.

Response:

No. In Pennsylvania, only the customers who are enrolled to receive outage notifications receive them after the outage management system ("OMS") identifies an outage that affects that a customer. If enrolled, customers can receive an outage notification independent of whether they did or did not initiate a call about their outage. OMS outage notifications did occur prior to the AMI deployment, going back to 2011. Enrolled customers receive outage notifications by way of text, email, or voice as described in the Company's response to PUC 5-1. PPL Electric Utilities Corporation ("PPL Electric") does not retain the exact messages used in the past, but the overall content and information presented in the Company's response to PUC 5-1 has remained relatively consistent since 2019.

After gaining automated Last Gasp notification functionality from AMI, PPL Electric is able to perform outage identification and respond faster compared to that which occurred before AMI deployment. Prior to AMI deployment, PPL Electric primarily relied on customers to contact the utility to report an outage. Last Gasp meter alerts have enabled PPL Electric to respond to and restore outages without receiving a call from a customer. From August 2019 through July 2020, PPL Electric was able to restore approximately 19% of outages without a customer reporting an outage from the use of Last Gasp meter alerts alone. Two years later, beginning in August 2020 through July 2022, the number of customers being restored without reporting an outage increased to approximately 25% on average.

PUC 5-8

Request:

Regarding the data used to establish the 22-minute faster outage notification, please show the following:

a. The distribution of average faster notification for each event and the event size (i.e., please calculate the average of outage notification for each event separately and plot that on an x-axis that represents notification difference and a y-axis that represents the population of affected customers in the event).

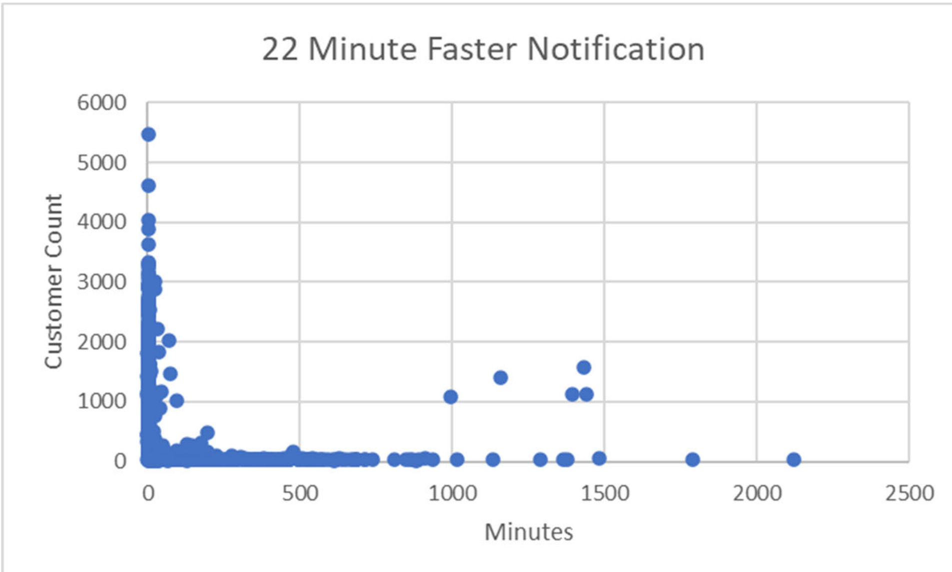
b. The distribution of faster notification for the entire dataset in bins at least as small as 30 seconds.

c. The following statistical data for the entire dataset referenced in part b:

    i. the maximum and minimum differences
    ii. the first quartile, median, and third quartile (do not assume a bin size)
    iii. the mode (assuming, in this case, bins at least as small at 30 seconds)

Response:

a. For outages in the dataset that were used to establish faster notification, the faster outage notification for each event was calculated separately and plotted below with the x-axis representing the notification variance and the y-axis representing the population of affected customers in the event. The faster outage notification was calculated for outages where both Last Gasp meter alerts and customer-initiated outage notifications were received into OMS. The calculation uses the variance between the timestamp in OMS indicating when the outage number ticket was created upon receiving Last Gasp meter alerts and the timestamp for the first customer initiated report of an outage sent to OMS from the customer information system. The 22-minute faster outage notification is a result of taking the simple average of the time variance between the outage ticket creation and the first customer report of an outage for all outages in the dataset.



b. For the entire dataset used to calculate the 22 minute faster outage notification, the data was organized into 30 second bins from 1 second through 30 minutes; one final bin was created for all data greater than 30 minutes. The distribution of the data is shown below:

Rank	Bin	Customer Count
1	0-30 Sec.	15,965
2	31-1 min.	67,733
3	1-1.5	236,554
4	1.5 - 2	242,054
5	2 - 2.5	146,006
6	2.5 - 3	104,079
7	3 - 3.5	51,075
8	3.5 - 4	34,699
9	4 - 4.5	21,271
10	4.5 - 5	12,536
11	5 - 5.5	12,253
12	5.5 - 6	11,079
13	6 - 6.5	10,948
14	6.5 - 7	5,311
15	7 - 7.5	5,544
16	7.5 - 8	8,901
17	8 - 8.5	5,249
18	8.5 - 9	4,218
19	9 - 9.5	3,532
20	9.5 - 10	2,312
21	10 - 10.5	2,926
22	10.5 - 11	1,816
23	11 - 11.5	3,184
24	11.5 - 12	1,899
25	12 - 12.5	1,870
26	12.5 - 13	1,792
27	13 - 13.5	848
28	13.5 - 14	2,610
29	14 - 14.5	966
30	14.5 - 15	1,265

Rank	Bin	Customer Count
31	15 - 15.5	866
32	15.5 - 16	2,382
33	16 - 16.5	1,349
34	16.5 - 17	3,122
35	17 - 17.5	1,008
36	17.5 - 18	1,169
37	18 - 18.5	691
38	18.5 - 19	891
39	19 - 19.5	646
40	19.5 - 20	1,150
41	20 - 20.5	673
42	20.5 - 21	699
43	21 - 21.5	1,050
44	21.5 - 22	3,255
45	22 - 22.5	247
46	22.5 - 23	1,304
47	23 - 23.5	3,522
48	23.5 - 24	249
49	24 - 24.5	463
50	24.5 - 25	238
51	25 - 25.5	170
52	25.5 - 26	1,342
53	26 - 26.5	433
54	26.5 - 27	285
55	27 - 27.5	523
56	27.5 - 28	369
57	28 - 28.5	359
58	28.5 - 29	238
59	29 - 29.5	163
60	29.5 - 30	285
61	>30	33,613

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c. For the entire dataset referenced in b),

	Minutes
Minimum	0.0167
Maximum	2120.8
1st quartile	2.867
3rd quartile	14.47
Median	5.9
Mode	1.83333333

PUC 5-9

Request:

Is CAIDI included in the Service Quality Plan in Rhode Island? Is it accounted for in Pennsylvania? Please explain.

Response:

No, CAIDI is not specifically included as a separate metric in the Rhode Island Service Quality Plan approved by the Rhode Island Public Utilities Commission in Docket No. 3628; rather, SAIDI and SAIFI metrics are included. Notwithstanding, CAIDI is indirectly available because it can be calculated by dividing SAIDI by SAIFI. Reports are available on the Rhode Island Public Utilities Commission's website at the following link: https://ripuc.ri.gov/eventsactions/docket/3628page.html.

In Pennsylvania, all investor-owned utilities report CAIDI, SAIDI, and SAIFI results. Each utility monitors and reports performance against CAIDI on a rolling 12-month basis and CAIDI on a three-year average. Reports are available on the Pennsylvania Public Utilities Commission's website at the following link: https://www.puc.pa.gov/filing-resources/reports/electric-service-reliability-report/.

PUC 5-11

Request:

Please provide the definition of major events and/or major storm events in Pennsylvania and compare it to the definition in use for RIE.

Response:

In Pennsylvania, pursuant to Pennsylvania Code 57.192, the term "Major Event" is used to identify an abnormal event, such as a major storm, and defined as either of the following: 1) an interruption of electric service resulting from conditions beyond the control of the electric distribution company ("EDC") which affects at least 10% of the customers in the EDC's service territory during the course of the event for a duration of five minutes or greater; or 2) an unscheduled interruption of electric service resulting from an action taken by an EDC to maintain the adequacy and security of the electrical system, which affects at least 1 customer.

In Rhode Island, the Amended Service Quality Plan approved by the Public Utilities Commission in Docket No. 3628 defines a Major Event Day as "[a] day in which the daily system SAIDI exceeds a threshold value, TMED," which is calculated using methodology defined in the IEEE Standard 1366-2012.[1] The calculation is based upon defining a Target Major Event Day ("TMED"), which is done statistically by applying log-standard deviation to historic reliability data. Any day with daily SAIDI greater than TMED that occurs during the subsequent reporting period is a Major Event Day. For example, for 2021, the TMED value was 6.67 minutes of SAIDI (using IEEE Std. 1366-2012 methodology).[2]

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[1] *See National Grid 2015 Amended Service Quality Plan, Definitions of Performance Standard Measurements*, Docket No. 3628.

[2] *See National Grid Petition For Approval To Classify March 1-2, 2021 As Major Event Days For Purposes Of Calculating Reliability Performance Standards Under The Electric Service Quality Plan*, Docket No. 3628 at 3.

PUC 5-14

Request:

This question references the ICE calculator inputs.

a. Of the population of outages included in the dataset used to establish the 22-minute faster outage, can the Company disaggregate customer classes in a manner that allows differentiation between residential, small commercial, and large C&I?
b. If within reasonable effort, please disaggregate the data and provide the difference in outage notification for each disaggregated class, or briefly explain why the effort is burdensome.
c. If possible, please provide a SAIFI score for each disaggregated class, or briefly explain why the data is not available.

Response:

a. through c.

The population of outages included in the dataset that was used to establish the 22-minute faster outage notification included a count of total customers interrupted for each outage. The dataset did not include any further details on each individual customer. The Company cannot disaggregate the dataset by customer class. The customer details for each outage in the dataset from 2019-2020 are no longer available because this data is not saved in the system. Furthermore, the Company cannot accurately re-create the individual customer details for each outage in the dataset because the customer data is dynamic in nature and constantly changing over time.

PUC 5-15

Request:

If the data described in the previous request (PUC 5-14) is available and can be gathered using reasonable effort:

a. Please reperform the value calculation described in the BCA but separately for each disaggregated class.

b. Please also conduct at least the following validation test:

    i. Input the disaggregated classes but use the whole-population SAIFI and CAIDI scores and compare the annual and cumulative value sums to the original values provided in the attachments and Book 2.
    ii. If disaggregated SAIFI scores were available to respond for part a, please rerun the model with disaggregated CAIDI but using the whole-population SAIFI and compare this to the response in part a.
    iii. Any other validation or briefly explain any relevant validation issues.

Response:

As explained in the Company's response to PUC 5-14, the requested dataset is not available.

PUC 5-16

Request:

Please confirm the inputs to the ICE calculator used for the BCA takes residential and non-residential customer counts as an input and the model outputs residential, small C&I, and medium and large C&I populations. Please show how these outputs compare to RIE's existing customer counts (in the response, please explain how the classes were grouped between the three classes in the ICE output).

Response:

The ICE calculator used for the BCA takes 2 inputs: residential and non-residential customer counts. Using the input total, the model then generates 3 outputs; residential, small C&I, and medium and large C&I populations. The ICE calculator includes an algorithm that splits the input for non-residential customers into small C&I customers and medium and large C&I customers. Rhode Island Energy customer count totals for residential and non-residential as of March 2022 were input into the ICE calculator

Because the ICE calculator did not split the non-residential customer counts correctly between small and large C&I customers, an adjustment had to be made to the actual Rhode Island Energy non-residential customer counts. Below are the inputs used to develop the Faster Notification benefit and the outputs from the ICE calculator. Also included are the adjustments made to reflect actual Rhode Island Energy small C&I and large C&I customers.

- ICE Calculator Customer Input:

The estimated value of reliability improvement model was applied for the State of Rhode Island using the following number of Rhode Island Energy active accounts as of March 2022:[1]

Number of Customers:	
Non-Residential	61,811
Residential	444,749
	506,560

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[11] Excludes MV-90 metered customers because those meters are not being replaced with AMF.

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- ICE Calculator Output:

Distribution of Benefits:

Sector	No. of Customers	Total Benefit (2022$)	Benefit per Customer (2022$)
Medium and Large C&I	10,083	$ 153,525,251	$ 15,226.1
Small C&I	51,728	$ 102,820,986	$ 1,987.7
Residential	444,749	$ 2,869,926	$ 6.5
All	**506,560**	**$ 259,216,162**	

- Customer Count Adjustment:

The number of customers from the ICE calculator output for Medium and Large C&I was adjusted from 10,083 to the Rhode Island Energy actual count of Medium and Large C&I of 8,469. The number of customers from the ICE calculator output for Small C&I was adjusted from 51,728 to the Rhode Island Energy actual count of Medium and Large C&I of 53,342. The benefit per customer remained the same and the adjusted customer count reflected a new Benefit total shown below.

Adjusted Distribution of Benefits:

Sector	No of Customers	Total Benefit (2022$)	Benefit per Customer (2022$)
Medium and Large C&I	8,469	$ 128,950,248	$ 15,226.1
Small C&I	53,342	$ 106,029,172	$ 1,987.7
Residential	444,749	$ 2,869,926	$ 6.5
All	**506,560**	**$ 237,849,346**	

From this adjustment, the Company divided the total benefit into 20 years resulting in an average benefit of $11,892,467.30 million per year.

This per year benefit was used in the BCA calculation as the annual benefit starting at year 1 (2022), inflated at 2% per year. The actual benefit started to accrue in year 2025 at 50% and accrued at 100% per year beginning in 2026 through 2041, resulting in a final benefit that was included in the BCA of $243.79 million.

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PUC 5-17

Request:

Did the meta-analysis the Company relied on to assume that Energy Insights will provide a 1-8% savings provide information about the effect on a system with a large amount of energy efficiency, and what the correlation between Energy Insights savings and program experience is?

Response:

The savings of 1-8% was a reference point used to help validate the 1.5% level of savings attributed to advanced metering functionality. The meta-analysis did not provide information about the effect on a system with a large amount of energy efficiency nor did it discuss the correlation between Energy Insights and program experience. (Please note: "Energy Insights" is the name given by the Company to the benefit being estimated; it did not originate from the meta-analysis report.) The meta-analysis used as a source of information for energy insights savings focused "on the potential application of AMI tools to realize customer energy efficiency."

The Company relied upon both the meta-analysis referenced above and the values used by National Grid in its AMF filing in Docket No. 5113 to determine an amount of energy savings from AMF. National Grid used a high and low level of savings: 3.5% and 1.5%, respectively. The Company chose to use 1.5% savings because of Rhode Island's long history of energy efficiency, assuming a modest level of additional savings would be realized with the implementation of AMF. This level of savings attributed to AMF is at the bottom of the savings scale of the meta-analysis savings range, thus supporting our modest/conservative assumption.

PUC 5-19

Request:

What annual cost is assumed for Energy Insights?

Response:

Energy Insights, which include the costs for customer education and outreach, are a component of the Change Management spend in the BCA model. Costs are estimated at approximately $1.36 million across years 2 through 20; approximately $1.25 million between years 2 through 7; and approximately $116,000 between years 8 through 20.

These costs are reflected in the BCA Excel file provided as Confidential Attachment H; however, the annual timeline view is shown below for ease of reference:

DEPLOYMENT				POST-DEPLOYMENT / OPERATIONS					
2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
$0	$142,500	$285,000	$285,000	$178,125	$178,125	$178,125	$8,906	$8,906	$8,906

POST-DEPLOYMENT / OPERATIONS continued									
2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
$8,906	$8,906	$8,906	$8,906	$8,906	$8,906	$8,906	$8,906	$8,906	$8,906

Prepared by or under the supervision of: Philip J. Walnock

PUC 5-20

Request:

Approximately 50% of PPL customers access the customer portal. However, the Company was unsure of how often they log in or for what purpose (i.e., once a week, once a month to pay their bill, etc.). If that information is available, please provide. If it is available by customer class, please provide.

Response:

When a customer logs on to the portal, the customer will see the Dashboard, containing the Account Summary, which allows the customer to view various data and perform many tasks. See Attachment PUC 5-20 for a screenshot example. From the Account Summary, the customer can pay a bill, see account details, view current billing estimates for current usage, view monthly energy usage, and view supplier information. The customer portal does not track the specific purpose for which a customer accesses their Dashboard. For this reason, PPL Electric Utilities Corporation ("PPL Electric") does not have information on the reason the customer logs on to the customer portal because the customer could be doing multiple tasks and viewing multiple data about their account. In addition, PPL Electric does not have information by rate classification because a customer may have both residential and commercial accounts, and PPL Electric cannot separate which accounts the customer is viewing on the Account Summary. Please see the Company's response to PUC 5-22 for portal usage data.

PPL Electric Utilities

My Account | Outages and Issues | Ways to Save | More | Español | Search | Contact Us | Sign Out

Account Summary

123 Street Dr Atown PA ... (12345-67890)

View all accounts >

Amount Due

$0.00

Autopay On | Manage >

Pay Now

Account Details

Previous Balance	$0.00
Current Bill	$0.00
Payments (1)	-$94.00
Account Balance	$0.00

✓ There is no payment due at this time.

View Bills & Payments >

Bill-to-Date Estimate* — $54.01

22 days into 34-day billing cycle ending Mar 13

Usage-to-Date ..... **241 kWh**
Average Daily Cost **$2.46**

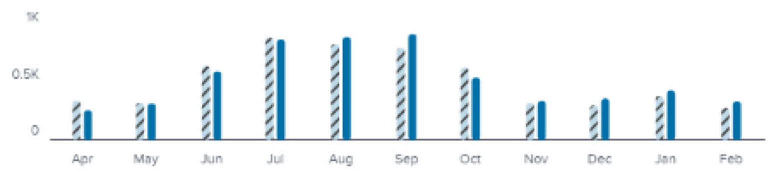
*Your bill-to-date estimate is based on PPL Electric Utilities' price for generation and transmission as of the previous day.

View Ways to Save >

Monthly Energy Use

February **357 kWh**

56 kWh more than this month last year



View Usage Details >

Electricity Supplier

ABC Supplier
1-855-555-5555

Supplier Rate	**8.315¢/kWh**
PPL Price to Compare*	**14.612¢/kWh** Valid until May 31, 2023

*PPL's Price to Compare is the rate customers pay if they don't shop suppliers. It is based on PPL buying electricity on the supplier market and passing the price to customers without markup.

Shop Rates >

View Supplier Activity >

Update Privacy Settings >

PUC 5-21

Request:

Regarding the previously referenced meta-analysis, what information or conclusions about the nature of participation in programs or tools like Energy Insights led to the 1% to 8% of savings (for example account creation, logins, page views, etc.), or was that element not addressed in the analysis?

Response:

That element was addressed in the meta-analysis and the learnings from the assessment in that study included the fact that education and "marketing" programs will be necessary to achieve the 1-8% levels of energy efficiency discussed in the study.

The study states:

". . . to the extent that AMI has been considered a means of influencing customer energy use, it has most often been viewed as a tool for affecting the timing of energy usage (e.g., for load shifting and demand response). Nevertheless, there are important ways that AMI can enable and support customer energy efficiency savings via several use cases.

"These strategic uses include:

- Enhancing the quality of insights on energy use from near-real-time feedback
- Providing time-varying pricing that reflects fluctuating energy costs at different times of day and year. Near-real-time feedback, combined with communications and possible automation, can better inform and motivate customers to respond to pricing signals and change their energy use accordingly.
- Targeting customers for programs best suited to their energy use profiles
- Promoting grid-interactive efficient buildings that extract more grid value from customer programs by providing more flexible demand
- Supporting energy procurement and meter-based pay-for-performance (P4P)
- Producing granular data needed for advanced measurement and verification of customer energy and demand savings (M&V 2.0.)
- Enabling conservation voltage reduction (CVR) on electricity distribution networks to reduce demand and energy use."[1]

[1] Leveraging Advanced Metering Infrastructure To Save Energy by Rachel Gold, Corri Waters, and Dan York January 3, 2020. Revised January 27, 2020. Report U2001, p. v.

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PUC 5-25

Request:

Regarding the responses to the previous request (5-24) and issues raised at the February 22 Technical Record Session, will some of the demand effects of EV TVR, whole-house TOU, and whole-house CPP occur in areas where, because excess capacity is high, lowering demand does not defer or avoid distribution capacity investment in a given year? If so, please address how the Company's model for avoided distribution capacity costs referenced in 5-24 appropriately accounts for these areas given the one-year (or year-by-year rather than year-over-year) effect of EV TVR, whole-house TOU, and whole-house CPP.

Response:

There are several points to consider when discussing the question of where, exactly, the demand effects of TVR, whole-house TOU, and whole-house CPP will occur over the next 20 years and whether, at any time during that 20-year period, a particular feeder will be at or near its capacity limit or have excess capacity.

1. The value that has been used for distribution capacity is an average value – $80.24/kW/year – and increased at a modest 2% per year value.
2. A 5.8% coincidence factor has been applied to the calculations, effectively lowering the value to $4.65/kW/year.
3. The total avoided distribution costs included in the BCA analysis are $3.93 million Nominal, which is 0.37% of the total benefits of $1,059.3 million Nominal benefits from AMF.
4. Although some feeders will no doubt have excess capacity in a given year, it seems unlikely that the excess capacity will remain for 20 years. One would anticipate that feeders will change their loadings over the 20-year time frame of this analysis.
5. The request would necessitate forecasting the loads for every existing feeder for every year of the analysis to determine when each feeder might be nearing overload versus having excess capacity. Given the anticipated mix of electrification and DER installations, the analysis would need to be done for more than just the peak hour. The analysis might need many hours analyzed each year to understand the impact of Electric Vehicles, Electric Heat Pumps, and two-way power flows created by DER. This type of analysis was done for the Company's Grid Modernization Plan where distribution cost avoidance is a much more substantial component of the benefit-cost analysis. Within that review, areas with excess capacity were evaluated after DER was added to the models. If

the excess capacity remained across the various hours of the test years, that area did not get infrastructure assigned and therefore there was no avoided value. Of note, areas with excess capacity were often served by upstream devices with limited capacity, meaning EV TVR, whole-house TOU, and whole-house CPP in areas of excess capacity could still contribute to upstream cost avoidance. The Company does not suggest this type of analysis for AMF evaluation. Because of the magnitude of the benefit described in #3, above, the system-wide average value is appropriate.

6. The request would also necessitate analyzing all new feeders that will need to be built to accommodate the anticipated mix of electrification and DER installations with the same issues described in #5, above.

The Company used very conservative assumptions in developing the avoided distribution benefits and does not believe consideration of the factors listed in the question would impact the benefit values significantly.

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Request:

To the extent the Company relied upon a forecast of demand and/or forecast of DER penetration for purposes of (i) calculating the BCA, (ii) determining the need for AMF, (iii) developing the timeline and investment schedule for deployment of AMF, and/or (iv) for any other purpose in developing the AMF proposal, please identify the forecast that was used and explain how the Company relied upon it.

Response:

The Company relied upon a forecast of demand and a forecast of DER penetration for calculating the BCA, but not for any other purpose in developing the AMF proposal. The forecast that was used and its derivation is included in Confidential Attachment H spreadsheet. The forecast and its derivation are shown in Tab 5-Benefit Inputs, rows 154-277 of the spreadsheet. Values highlighted in orange were values that were ultimately used in calculating the following benefits. How each forecast input was used to develop a particular benefit is shown in Tab 4-RIE BenCalc.

1. Energy Insights (energy and bill savings).
2. VVO/CVR (avoided energy; avoided system, transmission and distribution costs; avoided social costs; and DRIPE benefits).
3. Whole House TOU/CPP (avoided energy; avoided system, transmission and distribution costs; avoided social costs; and DRIPE benefits).
4. EV TVR (avoided energy; avoided system, transmission and distribution costs; avoided social costs; and DRIPE benefits).
5. Electricity Theft Reduction.

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