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

INITIAL COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON THE DISTRIBUTION SYSTEM PLANNING ANALYSIS PROPOSALS

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I. Introduction

On October 22, 2020, the Department of Public Utilities (the "Department" or "DPU") issued a Vote and Order Opening Investigation ("Order") in the above-captioned docket. In the Order, the Department proposed a new distributed energy resource planning process and cost allocation procedures ("Straw Proposal") and invited comments on the Straw Proposal and related cost allocation issues. The Straw Proposal included a provision for a long-term system planning program under which the Electric Distribution Companies ("EDCs") would be required to conduct system planning to identify upgrades necessary to accommodate interconnection of distributed energy resources ("DERs"). The cost of these upgrades would then be shared across both interconnection customers and other EDC customers. This system planning would thus serve dual goals of ensuring DER is interconnected more rapidly (by building upgrades in anticipation of future DER) and fairly (by sharing upgrade costs of all benefiting users instead of burdening only the unlucky cost-causer).

Numerous parties, including the Massachusetts EDCs Eversource, National Grid, and Unitil and the Interstate Renewable Energy Council, Inc. ("IREC"), provided initial and reply comments on the Straw Proposal. One issue raised in those comments was the need to have the EDCs develop system planning analysis proposals for review. Thus, following comments, on March 23, 2021, the Department directed the EDCs to develop those proposals, which were submitted by the three EDCs on April 23, 2021. The Department requested stakeholders' comments by May 7, 2021, which deadline was later extended to May 28, 2021. IREC appreciates the opportunity to provide these comments on the EDCs' system planning analysis proposals.

IREC is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. In service of our mission, IREC advances scalable solutions to integrate DERs, e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. The scope of our work includes developing and advancing regulatory policy innovations; generating and promoting national model rules, standards, and best practices; and updating interconnection processes to facilitate deployment of DERs and remove constraints to their integration on the grid. We have been an active participant in this docket to help identify effective cost allocation tools that will facilitate increasing DER interconnection.

The EDCs' system planning analyses are key components of optimizing grid planning to accommodate DER and the Commonwealth's clean energy goals. As we explained in our December 23, 2020 Initial Comments and February 5, 2021 Reply Comments on the Department's Straw Proposal, IREC strongly supports proactive distribution planning in Massachusetts.[1] Planning ahead to accommodate both DER and changes to load patterns is important, especially in light of the Commonwealth's increasingly constrained infrastructure and increasing demand for access to clean distributed energy. We note in particular the importance of this process is light of Massachusetts' leadership in the movement toward building

[1] *See generally* MA Dept. Pub. Utils., Dkt. 20-75, Comments of the Interstate Renewable Energy Council, Inc. on the Distributed Energy Resource Planning Proposal ("IREC Straw Proposal Initial Comments") (Dec. 23, 2020); MA Dept. Pub. Utils., Dkt. 20-75, Reply Comments of the Interstate Renewable Energy Council, Inc. on the Distributed Energy Resource Planning Proposal ("IREC Straw Proposal Reply Comments") (Feb. 5, 2021).

electrification and the transition away from gas as an end-use energy service in buildings (i.e., heating, cooking, and other residential and commercial uses).[2]

We also note that while the Department currently undertakes electric and gas utility distribution planning through largely separate processes, gas decarbonization and building electrification require a new paradigm, where electric and gas distribution planning are performed in a more coordinated, holistic manner. For example, one potential pathway for gas planning is to replace leak prone pipes with district heat systems. In order to enable such innovative approaches to decarbonization, electric utilities will have to take into account the anticipated electric load growth when planning grid upgrades, which should be informed by gas planning decisions. This is just one potential use case for coordinated electric and gas distribution planning. While coordinated planning is not the subject of this proceeding, IREC recommends that the Department consider a process for more explicitly and effectively linking electric and gas distribution utility planning efforts.

Here, each EDC provided a proposal for how it would conduct a system planning analysis, following the general framework suggested by the March 23, 2021 hearing officer memorandum.[3] Though the level of detail provided varied, all EDCs provided some insight into the assumptions they would use when modeling load and DER growth, how they would assess impacts of the load and DER, and how they would engage stakeholders throughout the process.

To evaluate the three EDCs' proposals, IREC retained New Energy Advisors, LLC ("NEA") to provide an expert report analyzing the proposals. NEA's report was prepared by

[2] *See generally* MA. Dept. Pub. Utils., Dkt. 20-80.

[3] *See* MA. Dept. Pub. Utils., Dkt. 20-75, Procedural Notice, Request for Comments, and Information Requests at 3-4 (Mar. 23, 2021).

Curt Volkmann, an electrical engineer with over 35 years of experience, who specializes in providing expert advice regarding distribution planning and grid modernization. Mr. Volkmann has served as an expert witness or technical advisor in such proceedings in over a dozen states, including California, Maryland, and New York. Mr. Volkmann's curriculum vitae is attached hereto as Exhibit 1. NEA's report on the EDCs' proposals (the "NEA Report") is attached hereto as Exhibit 2 and incorporated into these comments by this reference.

As explained below in more detail and in the NEA Report, IREC's recommendations fall into three broad categories: (1) necessary clarifications EDCs must make to their proposals before the Department can approve them, (2) substantive guidelines the Department should adopt to guide the EDC's assumptions and modeling to ensure accurate identification of the most broadly beneficial necessary upgrades, and (3) requirements for an effective stakeholder process. The Department and EDCs are on the right path here to developing a leading proactive planning and cost allocation program. However, the Department should take the steps recommended here to give the process the best chance of efficiently and effectively helping the Commonwealth achieve its clean energy goals and avoid unnecessary infrastructure upgrades.

II. The Department should require the EDCs to use accurate and supported assumptions when modeling DER impacts and to employ an integrated approach to system planning.

Each EDC proposes a similar multi-stage planning process that forecasts future distributed load and generation, models the effects of anticipated DERs on the grid, and conducts more detailed study to determine what upgrades are required to accommodate forecasted load and DER growth.[4] As explained in our previous comments in this docket,[5] IREC supports this proactive approach to facilitating interconnection of DER. However, as discussed more fully in the attached NEA Report, the Department should ensure that the EDCs accurately model the impact of DERs on their Electric Distribution Systems ("EDS"). The Department also should require the EDCs to take an integrated approach to system planning that evaluates load and generation needs together. This approach will allow the EDCs to identify and implement multi-value upgrades that can simultaneously accommodate load growth (and buildings and transportation electrification) and allow higher penetration of DER.

A. DER modeling should accurately capture real-world DER impacts.

As the NEA Report explains, distributed generation ("DG") and other DER resources can impact the distribution system in a number of ways:

> During high-demand periods, DG output and the discharge of energy storage can serve local load, contribute to peak demand reductions, and reduce line losses. During low daytime loading periods (i.e., cool days in the spring or fall), solar DG output can sometimes exceed local load, resulting in reverse power flow with the potential for system violations. However, energy storage in charging mode can alleviate these negative impacts by absorbing excess solar DG output during these daytime periods.[6]

This description highlights both positive and negative impacts that DERs can have on the grid.

[4] *See* MA. Dept. Pub. Utils., Dkt. 20-75, Eversource D.P.U. 20-75 System Planning Memorandum ("Eversource System Planning Proposal") at 2-3, 8-13 (Apr. 23, 2021); MA. Dept. Pub. Utils., Dkt. 20-75, National Grid System Planning Analysis Proposal ("National Grid System Planning Proposal") at 4-6 (Apr. 23, 2021); MA. Dept. Pub. Utils., Dkt. 20-75, Fitchburg Gas and Electric Light Company d/b/a Unitil System Planning Analysis Proposal ("Unitil System Planning Proposal") at 3-8 (Apr. 23, 2021).

[5] *See generally* IREC Straw Proposal Initial Comments; IREC Straw Proposal Reply Comments.

[6] NEA Report at 7.

IREC is concerned that the assumptions built into some of the EDCs' models may overstate negative DER impacts and understate DER benefits. Because these assumptions will directly impact system upgrade decisions, the EDCs should establish more accurate modeling of DER impacts. Additionally, while their proposals seem to be headed in the right direction, National Grid and Unitil do not fully describe the assumptions built into their models, and the Department should require them to do so before approving their proposals.

1. The EDCs' proposals would likely overstate negative DER impacts.

Eversource and Unitil both propose approaches to modeling minimum load that appear to overstate the potential negative impact of solar DG. Both of these EDCs model solar DG output at 100% of nameplate capacity during daytime minimum load.[7] But as the NEA Report explains, actual peak solar DG output almost never reaches 100% of nameplate capacity, even during "clear sky" days.[8] In particular, NEA's modeling shows that solar DG "clear sky" output varies from month to month and that the assumption of 100% output may overstate DG impacts by as much as 20%.[9] For these reasons, the Department should require the EDCs to account for seasonal variation in DG output when modeling for daytime minimum load impacts and to use realistic assumptions instead of defaulting to an unrealistic and likely impossible "worst-case" scenario.[10]

[7] Eversource System Planning Proposal at 10; Unitil System Planning Proposal, Attachment A, at 15; *see also* NEA Report at 8, 9.

[8] NEA Report at 9-10.

[9] *Id.*

[10] *See also id.* at 10 ("NEA recommends that the Department require the EDCs to establish methodologies for determining the impact of solar DG during periods of daytime minimum load that are not based on 100% of AC nameplate rating, but rather are based on the actual maximum DG output in the month during which the daytime minimum load occurs.").

For its part, National Grid does not state in its proposal how it models DG output during minimum load events. Because this assumption could significantly impact future upgrade decisions, IREC recommends that the Department require National Grid to make its proposed assumptions explicit so that they can be evaluated for accuracy prior to Department approval.

Eversource also likely overstates the negative impacts of energy storage in its minimum load model. Eversource assumes that all storage resources will discharge at 100% of their rated output during periods of daytime minimum load.[11] This assumption inflates energy storage impacts during low load events for two reasons. First, it is highly unlikely that all storage resources connected to a circuit or substation will simultaneously operate in the same mode.[12] Second, the assumption fails to consider that some storage resources likely will be *charging* during times of low load. NEA notes that while some non-residential customers with stand-alone storage may discharge during periods of low load to minimize demand charges, both residential and non-residential customers with paired solar DG and battery storage will often charge some or all of their storage during the day when load is low.[13]

Instead of relying on unrealistic and unsupported assumptions about how storage will be used and impact the grid, the Department should require the EDCs to conduct real-world measurements of residential and non-residential storage discharge on a select number of circuits to inform their assumptions on storage impacts.[14] And in the case of National Grid and Unitil, the Department should require these EDCs to expressly identify their assumptions for distributed

[11] Eversource System Planning Proposal at 10.

[12] NEA Report at 11.

[13] *Id.* at 11.

[14] *See id.* at 11-12.

energy storage discharge since their proposals do not do so currently, taking into account the need to provide evidence to support their assumptions.[15] Once the EDCs report on the real-word analyses that will inform their model assumptions, the Department should require uniform adoption of the same assumptions across all three system planning proposals.[16]

2. The EDCs likely understate positive DER benefits.

In addition to overstating the negative impacts of DERs, Eversource's proposal likely understates the benefits DER would provide to the EDS, while the other EDCs do not provide clarity on how their analyses would account for DER benefits. In particular, Eversource's peak load model assumes that only 10% of DG nameplate capacity is available to serve local demand during peak load periods.[17] That assumption likely understates the load-reducing benefit of DG, which has been documented by other utilities to be more significant than Eversource assumes.[18] For example, NEA's report references an empirical study of 860 solar DG systems across Southern California Edison's service territory, which found 30-45% of DG nameplate capacity available to serve local demand at noon and 13-23% at 4 p.m.[19] Real-world studies like this show that the 10% assumption built into Eversource's modeling likely significantly underestimates the ability of DG to help meet peak load demand.

To avoid underestimating DER benefits, which would lead to identification and construction of unnecessary system upgrades, the Department should require the EDCs to model

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[15] *See id.* at 12.

[16] *See id.*

[17] Eversource System Planning Proposal, Attachment 1, at 31.

[18] NEA Report at 7-8.

[19] *Id.* & Attachment A.

DER benefits during peak load periods based on actual output data gathered in studies similar to the one performed by Southern California Edison.[20] Furthermore, the Department should require National Grid and Unitil, who do not indicate how their models account for the peak load-reducing benefits of DG, to make explicit the assumptions built into their models and likewise require the assumptions to be based on real-world data.

B. The Department should require the EDCs to evaluate load and generation impacts together to better accommodate load growth and higher penetration of DERs.

All three EDCs generally promote an integrated planning approach that evaluates load and generation needs together to identify optimal system upgrades.[21] National Grid, for example, proposes identification of multi-value solutions that simultaneously address load-driven and DG-driven grid needs.[22] We are strongly supportive of an integrated approach to evaluating forecasting load and DG. However, we note that National Grid's and Unitil's proposals do not elaborate on all the necessary details, and more detailed proposals will be required prior to Department approval.

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[20] *See id.*

[21] *See* National Grid System Planning Proposal at 19 ("[S]ignificant 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."); Eversource System Planning Proposal at 1 ("High DER penetration especially . . . requires EDCs to develop a comprehensive, holistic approach to system planning considering the integrated impacts of both load growth . . . as well as DER adoption, rather than looking at these two dynamics as separate and independent activities."); Unitil System Planning Proposal at 4 ("Historically, DER forecasting and system load forecasting has been performed separately. However in 2021 Unitil began directly incorporating DER projections into system load forecasts. This is done by combining the individual system load and system DER forecasts . . . to create an overall system load forecast.").

[22] *See* National Grid System Planning Proposal at 3.

In contrast, Eversource provides enough detail to evaluate its proposal, but does not provide an integrated approach. Instead, Eversource bifurcates its system analysis into two largely separate and sequential steps. Eversource proposes first performing a maximum load analysis, as it has traditionally done, to address load capacity deficiencies during summer peak load days.[23] The company then proposes incorporating any resulting system topology updates into its minimum load model to identify DER impacts.[24]

This sequential approach to evaluating system upgrades fails to account for situations where circuits can simultaneously accommodate additional load and generation without requiring expensive upgrades. As highlighted in NEA's report, Eversource's approach would neglect to account for situations where forecasted increases in vehicle charging, electric heating, or other end-use energy service load could alleviate DG-driven issues related to reverse power flow on the same circuit.[25] Likewise, an upgrade to a circuit's hosting capacity may allow the circuit to accommodate additional load without the need for load-related upgrades.[26]

Without forecasting and evaluating distributed load and generation impacts together, the EDCs likely will overestimate the need for upgrades to serve forecasted growth. Thus, the Department should require Eversource to either adopt a more holistic approach, like that suggested by National Grid, or minimally, clarify how its bifurcated approach will properly account for multi-value solutions such as those highlighted in NEA's report.[27]

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[23] Eversource System Planning Proposal at 19.

[24] *Id.* at 19-20.

[25] NEA Report at 6.

[26] *Id.*

[27] *See id.*

III. The Department should ensure that the EDCs' distribution system planning processes provide for meaningful stakeholder input to ensure accurate forecasting of upgrade needs.

As we emphasized in our earlier comments[28] and as further explained in NEA's report,[29] a well-planned and meaningful stakeholder process will be essential to the EDCs' distribution planning. An effective process will solicit stakeholder input at key points to inform the EDCs' knowledge of DER development plans and other factors that could impact DER forecasts. Specifically, as explained in more detail by NEA, we highlight the importance of National Grid's "Stage 1, Task 1" stakeholder engagement point, which solicits "developer, municipal, state agency, conservation group, or other stakeholder perspectives on DG and other DER projects."[30] The Department should require all EDCs to solicit the same input from key stakeholders.

Notably, Eversource rejects the idea of any stakeholder input on its analysis of load impacts.[31] As explained above, Eversource's planning approach, which includes bifurcated load and DER impact analyses, is problematic to begin with. Its shortcomings are compounded by the utility's insistence that stakeholder input related to load forecasting is unwelcome. On the contrary, stakeholders and the Department should be able to review Eversource's load assumptions, which directly impact identification of multi-value upgrades, the costs of which may be borne in part by DER developers. As recommended by NEA, the Department should instead require all EDCs to engage in stakeholder processes that provide for holistic and

[28] IREC Straw Proposal Initial Comments at 10-11; IREC Straw Proposal Reply Comments at 10-12.

[29] NEA Report at 15-16.

[30] *Id.* at 12-13; National Grid System Planning Proposal at 10-11.

[31] Eversource System Planning Proposal at 26.

comprehensive review and evaluation of EDC plans, which will facilitate identification of multi-value upgrade solutions to accommodate both load-driven and DER-driven grid needs.[32]

Beyond the information-gathering phase, it is important for stakeholders to be able to provide input on both proposed upgrades and those upgrades' costs, which all EDCs' current proposals include.[33]

Next, we encourage the Department to define how the EDCs should engage meaningfully during the stakeholder process and give real weight to stakeholder input.[34] This will ensure that all stakeholder-raised issues are addressed and that stakeholders are aware of and able to engage on any issues of concern for the EDCs. When EDCs are permitted to simply observe or set the topics for stakeholder input without actively engaging in the process, there is a significant risk of reduced effectiveness. For example, without active EDC participation, stakeholders may not know what concerns the EDCs have about a stakeholder's proposal, and thus an opportunity for discussion of the issue and optimal resolution is lost. Further, the Department should develop checks to ensure that EDCs appropriately integrate stakeholder insight into their planning. For example, the Department could provide a staff member to observe stakeholder meetings, who would later review the outcome of stakeholder meetings.

As we explained in earlier comments, stakeholder processes—especially complex and important ones like the one at issue here—function best when facilitated by a neutral third party

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[32] NEA Report at 14.

[33] *See* National Grid System Planning Proposal at 26-27; Unitil System Planning Proposal at 9; Eversource System Planning Proposal at 20-21.

[34] *See* NEA Report at 15-16.

with subject matter expertise.[35] National Grid shares this view.[36] This facilitator could be a Department staff member or an outside expert approved by the Department, but the key is that the EDCs should not select or control this individual. This approach both frees up the EDCs to act as participants in the stakeholder process and removes them somewhat from a position of undue influence over the process. Transparency and output quality of the meetings will benefit.

To ensure that the three EDCs' parallel planning and stakeholder engagement processes do not become an outsized burden on stakeholders (especially those with limited resources), the Department should require the EDCs to coordinate to make the stakeholder engagement sessions for each step of the process occur on the same day or same consecutive days, in the same location. For example, if a single full day is scheduled for stakeholder engagement, 2.5 hours could be allotted to engagement with each EDC. This will avoid overburdening stakeholders, who frequently have projects or other interests across multiple EDCs' territories and would thus want to engage in multiple EDCs' processes.

We also recommend that the Department require stakeholder meetings have effective remote-participation capabilities, such as through videoconference tools. While there is no replacement for the dynamic of in-person meetings—and we believe stakeholders meetings should generally be in-person—the pandemic has shown that remote meetings can be effective when done right. This will allow participants who do not live close to the meeting location to participate without significant expense or carbon footprint.

[35] IREC Straw Proposal Reply Comments at 11.

[36] MA. Dept. Pub. Utils., Dkt. 20-75, National Grid Reply Comments on Straw Proposal at 10-11 (Feb. 5, 2021).

Finally, we encourage the Department to take additional steps recommended in the NEA Report that optimize the stakeholder process, including (1) requiring EDCs to share slides and presentations well in advance of meetings and allow stakeholders to prepare; (2) allowing stakeholders to submit questions in advance to be addressed at meetings; and (3) requiring the EDCs to maintain a joint website for information related to the distribution planning process.[37]

IV. The Department should balance the benefits of consistent planning processes with need to provide some flexibility to the EDCs.

IREC recognizes the need for the EDCs to develop a planning process that works best for the peculiarities of their EDS and their internal practices and procedures. However, we caution that the Department still must set some standards for the process, which will ensure consistent inputs and reliable outcomes. This is why we have asked the Department in our comments here to establish basic and clear guidelines on allowable assumptions and approaches to modeling. This ensures all three EDCs are using best practices when forecasting load and DER growth and the impact of such factors on the grid, and that the Department and stakeholders can better compare processes and results across EDCs.

Also, we recommend a consistent approach to stakeholder engagement to ensure stakeholders can participate effectively and efficiently across the three EDCs. As explained above, this requires both cooperation on the logistics of the stakeholder process, to the extent possible, and a common approach to the information exchanged during the process.

V. Conclusion

IREC again commends the Massachusetts Department of Utilities for seeking proactive solutions to grid capacity constraints and cost allocation issues that can stymie clean energy

[37] NEA Report at 16.

development in the Commonwealth if left unresolved. As explained in detail above and in the NEA Report, we recommend the Department require specific clarifications from the EDCs on their proposals, or revisions to those proposals, before approving them. We also recommend that the Department establish certain guidelines for the stakeholder engagement process, which will optimize the outcome of the planning process and ensure the most cost-effective and broadly useful grid upgrades are pursued. We summarize those recommendations here.

Overall, IREC recommends that the Department adopt a planning process similar to the one outlined in National Grid's proposal, which would identify multi-value upgrades that simultaneously address load- and DER-driven grid needs.

IREC recommends that the Department require the EDCs to provide the following **clarifications** to their proposals:

- Require Eversource to clarify how its proposed bifurcated planning process will effectively identify multi-value solutions to address load- and DER-driven grid needs.
- Require Eversource to conduct a sensitivity analysis (e.g., 0/50/100% of residential, 0/50/100% of non-residential storage resources discharging during low daytime load periods) on a select number of circuits to determine the impact of this assumption on its Minimum Load Model and revise its proposal if warranted base on this information.
- Require National Grid and Unitil to explain how they account for energy storage in their daytime minimum load analyses.
- Require National Grid to explain how it models DG output during minimum load events.

IREC recommends that the Department establish the following **guidelines** for the EDCs' planning processes:

- Require the EDCs to develop methodologies for quantifying the load-reducing benefits of DG during peak load periods based on actual DG system output data collected across the EDC service territories.

- Require the EDCs to establish methodologies for determining the impact of solar DG during periods of daytime minimum load that are not based on 100% of AC nameplate rating, but are based on the maximum DG output in the month during which the daytime minimum load occurs.

- After receiving the results of Eversource's sensitivity analysis and explanations of how all the EDCs account for energy storage (as explained above), identify the appropriate assumptions for energy storage operational modes (i.e., charging vs. discharging) during periods of low daytime loads, and require all three EDCs to use those assumptions.

IREC recommends that the Department provide for a robust and effective **stakeholder process** by:

- Requiring all EDCs to conduct the same stakeholder engagement as proposed by National Grid in Stage 1, Task 1, which will ensure that the each EDC incorporates a common set of Commonwealth-wide assumptions into its DER planning.

- Requiring all EDCs to develop and conduct a stakeholder engagement process that allows stakeholders to holistically and comprehensively evaluate the EDCs' plans in order to identify multi-value solutions that simultaneously address load-driven and DER-driven grid needs.

- Requiring the EDCs to coordinate and synchronize stakeholder meeting schedules.

- Appointing an objective third-party subject matter expert to facilitate stakeholder meetings.

- Requiring EDCs to actively participate in the stakeholder process.

- Requiring the EDCs to provide slides and other presentation materials for the stakeholder meetings in advance and allow stakeholders to submit questions in advance to be addressed at the meetings.

- Requiring the EDCs to develop and maintain a joint website regarding the distribution planning process.

- Requiring that all stakeholder meetings have a virtual attendance option.

DATED: May 28, 2021

Respectfully submitted,

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Exhibit 1

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Experience

New Energy Advisors, LLC, Strategic Advisory Company, Lake Geneva, WI (2013 – present)

President

Advising businesses, non-profits and local governments on energy, water and sustainability opportunities

- Expert witness and technical advisor for environmental and consumer advocates in distribution planning, grid modernization, and distributed energy resources regulatory proceedings in AR, AZ, CA, IA, IL, MA, MD, MI, MN, NC, NY, OH, UT, and VA
- Guest lecturer at Chicago-area universities on the topics of energy and sustainability

Environmental Law & Policy Center, Nonprofit Public Interest Advocacy Organization, Chicago, IL (2013 – 2015)

Senior Clean Energy Specialist

Supported advocacy work on various clean energy and transportation policy issues

- Expert witness in several energy efficiency, renewable energy, and rate design regulatory proceedings
- Focused on opportunities to integrate distributed energy resources into electric utility distribution systems

Accenture LLP, Management Consulting and Technology Company, Chicago, IL (1994 – 2013)

Managing Director, North America Strategy and Sustainability (2010 – 2013)

Led the management consulting practice ($260+ million annual sales) focused on energy efficiency and intelligent infrastructure. Clients spanned the chemicals, metals, consumer products, financial services, telecommunications, utilities and federal/state/local government sectors.

- Responsible for sales and project delivery, product/service development, recruiting, alliance management
- Contributed to sales growth of more than 400% in 2 years
- Led creation of Energy Analytics for Cities framework; identified $175 million of energy savings from building retrofits for the City of Chicago
- Frequent speaker and subject-matter expert on the topics of utilities, smart grid, sustainability, clean energy

Partner and Executive Director, North America Utilities Client Group (2000 – 2010)

Managed sales ($10-30 million annually), profitability, and client satisfaction for consulting projects across a portfolio of gas, electric and water utilities. Projects included strategic assessments, smart grid/meter planning, asset management, merger integration, benchmarking, and process improvements

Senior Manager and Associate Partner, Strategic Services (1994 – 2000)

Led projects involving utility strategic planning, merger integration, cost reduction, and process reengineering

UMS Group, Management Consulting Company, Parsippany, NJ (1993 – 1994)

Senior Associate

Led the Power Delivery consulting practice and benchmarking programs for transmission, distribution and fleet management involving 40+ utilities in 10 countries (in Europe, Africa, North America, Australia/New Zealand)

Pacific Gas and Electric Company, Utility, San Francisco, CA (1984 –1993)

Electrical Engineer, Operations Planning Consultant, Project Manager

- Assessed impacts to distribution systems from energy efficiency and demand-side management programs
- Modeled impacts of distributed generation on system reliability and safety

Energie- und Verfahrenstechnik (EVT), Power Generation Equipment Manufacturer, Stuttgart, Germany (1983)

Software Developer

Designed steam generating systems for coal-fired power plants

Education

University of California at Berkeley, Haas School of Business

MBA - Concentration in Finance

University of Illinois at Urbana-Champaign

BS - Electrical Engineering, Concentration in Electrical Power Systems

Other

- Registered Professional Electrical Engineer, State of California (1987-1995)
- Patent holder (US Patent 20140114867 A1) for a system to reduce residential carbon footprints
- Chairman, Lake Forest, IL Collaborative for Environmental Leadership (2012-2018)
  - Led development of the City's first Sustainability Plan
- Chairman, City of Lake Forest Parks and Recreation Board (2012-2014)
- Member, City of Lake Forest Municipal Electricity Aggregation Committee (2011-2012)

Exhibit 2

Review of Massachusetts Electric Distribution Company System Planning Proposals

At the request of the Interstate Renewable Energy Council, Inc. ("IREC"), this report summarizes a review by New Energy Advisors, LLC ("NEA") of the distribution system planning proposals from the Massachusetts Electric Distribution Companies [1] (individually "EDC" and collectively "EDCs") in response to the Massachusetts Department of Public Utilities ("D.P.U." or "Department") March 23, 2021 Hearing Officer Memorandum.[2] NEA is an independent consulting firm focused on regulatory proceedings related to renewable energy, distribution planning and grid modernization.

Background and Context

In August 2008, the Global Warming Solutions Act ("GWSA") became law in the Commonwealth, making Massachusetts one of the first states in the U.S. to adopt ambitious greenhouse gas ("GHG") reduction limits. The GWSA requires the Office of Energy and Environmental Affairs ("EEA") to set emissions limits every 10 years together with an implementation plan to achieve the limits (Clean Energy and Climate Plan or "CECP"). The Commonwealth's initial GWSA implementation plan, the 2020 CECP, was published in 2010 and updated in 2015. During his January 2020 State of the Commonwealth Address, Governor Charles Baker committed Massachusetts to achieving net-zero emissions by 2050, and the EEA thereafter established a 2050 statewide emissions limit of Net Zero greenhouse gas emissions.[3]

The state's most recent GWSA implementation plan, the Interim 2030 CECP[4], was published on December 30, 2020, together with a 2050 Decarbonization Roadmap.[5] Among other actions, both the 2030 CECP and the 2050 Roadmap call for large

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

[2] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13292025

[3] https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download

[4] https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download

[5] https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download

deployments of solar distributed generation ("DG"), increased deployment of energy storage, widespread deployment of electric vehicles replacing gasoline and diesel engines, and widespread deployment of electric heat pumps replacing gas or oil furnaces and boilers.

Recognizing the impacts to the distribution system from accelerated deployment of DG, electric vehicles ("EVs"), and heating electrification ("HE"), the Department issued an order on October 22, 2020 opening an investigation (D.P.U. 20-75) into two issues for the EDCs: (1) planning for distributed energy resources ("DER")[6] and (2) assignment and recovery of costs for the interconnection of DG to an EDC's electric power system ("EPS").

The D.P.U. 20-75 initiating Order included a Straw Proposal for a distribution system assessment process and a series of questions for the EDCs and stakeholders. After receiving initial and reply comments, the Department issued a memorandum on March 23, 2021 requiring the EDCs to submit system planning analysis proposals to implement the new distribution system assessment process. The D.P.U. 20-75 Straw Proposal comments and EDC proposals are the subject of NEA's review and this report.

The EDCs' Proposals

National Grid proposes to conduct its system planning analysis in four stages: 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. National Grid refers to its approach as Integrated Distribution Planning, and intends to incorporate stakeholder input during Stages 1 and 3.

Eversource is proposing a five step process: 1) Define and Establish Planning Scenarios; 2) Forecast Deployment of DER; 3) Assess Impact of High DER Penetration; 4) Determine Transmission and Distribution Upgrades; and 5) Define and Allocate System Capacity. The company also provided its recently developed Distribution System

[6] Consistent with the D.P.U. 20-75 Order, DER include 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).

Planning Guide. Eversource intends to solicit stakeholder input only for its planning assumptions and solution development related to forecasted DER.

Unitil provided a description of its existing processes for Electric System Planning (115kV and 69kV) and Distribution System Planning (13.8kV and 4.16kV), and explains how it is enhancing the processes to include forecasting and analysis of DER. The company also provided its Electric System and Distribution Planning Guides, along with its electrical equipment rating procedures. Unitil proposes stakeholder participation at three stages of its annual forecasting and planning process.

NEA believes that, of these three proposals, National Grid's proposed 4-stage Integrated Distribution Planning process is most reasonable and will allow for the identification of optimal solutions (with stakeholder input) to address multiple grid needs. We discuss specific issues raised by the proposals in more detail below.

The Need for an Integrated Approach to Distribution Planning

The Commonwealth's widespread adoption of electric vehicles and heating electrification will fundamentally change EDC loads and load shapes. In addition to increased magnitudes of electricity peak demand and usage, circuits and substations that are summer peaking today may become winter peaking in the future.

Traditionally, EDC planners have only been concerned with peak demands in identifying overloaded system conditions. With increasing penetrations of DG, planners are now also concerned about periods of low loads and high DG output. As Eversource explains, "Historically, EDCs focused primarily on maximum (peak) load analysis as the driver for system design changes. Peak load analysis is focused around a specific time during a peak day when the system experiences the highest net demand, typically occurring during high load and low DG generation times. With the introduction of large quantities of DG potentially leading to reverse flow during low load periods, this paradigm has shifted, and minimum load models have become just as important, depending on the amount of installed DG."[7]

With significant increases in load from electrification combined with growth in DG deployment, EDC planners must increasingly identify creative solutions to address increasingly complex distribution grid needs.[8] Fortunately, many solutions can have multiple benefits and can simultaneously address multiple grid needs. National Grid noted this and provided an example, stating: "Consider a 40-year-old overhead line replaced with a larger conductor in a tree resistant fashion. That project could address asset condition, loading, contingency, reliability, DG enablement, EV enablement, and HE enablement issues and that project would create significant benefits for all customers due to its comprehensive nature."[9]

With this increased complexity, the EDCs must now examine both conventional and DER-driven grid needs in a comprehensive, integrated way to identify optimal solutions. As National Grid explained, "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."[10] Specifically, National Grid explained that its assessment "will identify multi-value upgrades that provide solutions to traditional electric power system constraints (e.g., load relief, reliability, asset condition) and also enable the interconnection of additional capacity beyond currently proposed DG Facilities."[11]

Eversource also acknowledges the importance of an integrated approach to distribution planning, stating: "High DER penetration especially at saturated stations requires EDCs to develop a comprehensive, holistic approach to system planning considering the integrated impacts of both load growth (including EV adoption, energy efficiency,

[7] Eversource D.P.U 20-75 System Planning Memorandum, April 23, 2021, p. 8

[8] Distribution grid needs include capacity to serve load, high/low voltage, reliability/resilience, asset condition, and DER hosting capacity.

[9] National Grid Comments on Straw Proposal, December 23, 2020, p. 14

[10] National Grid System Planning Analysis Proposal, April 23, 2021, p. 19

[11] National Grid System Planning Analysis Proposal, April 23, 2021, p. 3

demand response, sector conversion, etc.), as well as DER adoption, rather than looking at these two dynamics as separate and independent activities. Therefore, any assessment of long-term system planning needs should identify upgrades that provide a broader benefit and can accommodate various types of load growth, as well as high penetration of DER."[12]

However, NEA is concerned that Eversource's proposed approach to its assessment may not result in optimal solutions to address multiple grid needs. In contrast to National Grid's proposal, which includes a single, integrated load analysis with stakeholder input, Eversource conducts two separate and distinct load analyses - a Maximum Load Model without stakeholder input, followed by a Minimum Load Model. The Maximum Load Model evaluates system conditions during peak load, low DG output conditions (i.e., hot, cloudy summer days). For its Minimum Load Model, Eversource evaluates conditions "[d]uring low loading conditions, typically spring or fall months." Eversource explains that under low loading conditions, "distributed generation can significantly offset load, or even surpass it, causing what is more commonly referred to as reverse power flow. This can also lead to increased equipment loading and power quality concerns, such as elevated (over-) voltages."[13]

Eversource proposes to conduct the Maximum and Minimum Load modeling sequentially each year (Maximum Load model first followed by the Minimum Load model).[14] However, Eversource proposes to solicit stakeholder input on planning assumptions and solution development for the Minimum Load model only. Eversource explains, "reinforcements proposed as part of traditional distribution (Max Load) planning process are designed to support the Company's public service obligation to provide safe and reliable electric service to all customers. These projects will be defined and incorporated into the Company's capital plan *independent* of the stakeholder process. Projects proposed under the Company's capital plan will be finalized prior to the development of the Preliminary Solution presented at the September Stakeholder meeting. This

[12] Eversource D.P.U 20-75 System Planning Memorandum, April 23, 2021, pp. 1-2
[13] *Id.*, p. 9
[14] *Id.*, pp. 19-20

guarantees that projects proposed as part of the traditional capital process are authorized ahead of time and included in the Min Load base models prior to developing high level DER-driven solutions."[15]

NEA is unclear how Eversource's proposed bifurcated approach with limited stakeholder input will result in multi-value solutions to address load-driven and DER-driven grid needs. As described above, it is important to examine the impacts of load growth and DER growth simultaneously in an integrated way. As an example, Eversource may upgrade a circuit to accommodate forecasted HE and EV charging (including workplace charging), which may increase daytime minimum load, which may potentially alleviate DER-driven issues related to reverse power flow on the circuit. Similarly, a circuit upgrade to increase its hosting capacity could allow for HE- and EV-related load growth on the circuit without the need for additional load-related capital investment. It is unclear how Eversource's proposed approach would model such multi-value solutions and their impacts.

NEA recommends that the Department adopt a planning process like the one proposed by National Grid, which would identify multi-value solutions that simultaneously address load-driven and DER-driven grid needs. At minimum, the Department should require Eversource to clarify how its proposed bifurcated planning process will identify such multi-value solutions.

Unitil is in the early stages of developing integrated system and circuit planning processes, and in 2021, began directly incorporating DER projections into load forecasts. Unitil also intends to add Minimum Daytime Load/Peak DER analysis to these processes in an attempt to identify potential future constraints due to anticipated DER penetration.[16] Given Unitil's limited integrated planning capabilities, its proposed approach is generally reasonable.

[15] *Id*., p. 14

[16] Unitil System Planning Analysis Proposal, April 23, 2021, pp. 4 and 6.

The Critical Need for Accurate Modeling of DER Impacts

Comprehensive, integrated planning requires accurate DER modeling, taking into account the fact that DG and other DER can have both positive and negative impacts on the EPS of the Commonwealth's EDCs. During high-demand periods, DG output and the discharge of energy storage can serve local load, contribute to peak demand reductions, and reduce line losses. During low daytime loading periods (i.e., cool days in the spring or fall), solar DG output can sometimes exceed local load, resulting in reverse power flow with the potential for system violations. However, energy storage in charging mode can alleviate these negative impacts by absorbing excess solar DG output during these daytime periods.

Accurate modeling of these DER impacts is critical, as it is the basis for identifying EPS upgrades to accommodate load growth and DER integration. NEA is concerned that Eversource's proposed approach (and possibly the other EDCs' approaches) may be understating the positive and overstating the negative impacts of DER, potentially resulting in unnecessary EPS upgrades.

As stated previously, Eversource conducts two distinct load analyses - a Maximum Load Model and a Minimum Load Model. For the Maximum Load Model, Eversource explains, "system planning considers current worst-case loading conditions on the system in combination with low DG output projections, ensuring that the system can supply loads on a hot, humid, cloudy summer day without failure."[17]

Eversource's model assumes that only 10% of DG nameplate capacity is available to serve local demand during these peak load periods,[18] which NEA believes may be overly conservative and understates the load-reducing benefit of DG. This assumption is also inconsistent with the approach taken by other utilities. For example, in its 2021 general rate case application, Southern California Edison ("SCE") explained its methodology for determining how much solar DG it can reasonably rely upon when adverse conditions, such as cloud cover, occur during peak load periods ("Dependable PV", see Attachment

[17] Eversource D.P.U 20-75 System Planning Memorandum, April 23, 2021, p. 9
[18] *Id*., Attachment 1, p. 31

A[19]). Utilizing output data collected from 860 solar DG systems across its service territory, SCE determined that Dependable PV ranges from 30-45% of its nameplate rating at noon and 13-23% of nameplate at 4:00 pm across its eight planning regions.

NEA was unable to determine how National Grid and Unitil account for the peak load-reducing impacts of solar DG.

We recommend that the Department require that the EDCs methodologies for quantifying the load-reducing benefits of DG during peak load periods be based on actual DG output data collected across the EDC service territories, like SCE's methodology.

NEA is also concerned that Eversource is overstating the potential negative impact of solar DG in its Minimum Load Model. Eversource assumes that solar DG's output is a worst-case 100% of its AC nameplate capacity during daytime minimum load[20], or what it refers to as maximum "clear sky" output. Eversource collects data to determine the days during which minimum loads occur and explains, "… the important events for the low load model typically occur during Spring and Fall months. To provide a complete set for a given calendar year, recording should be completed at least until (the) end of October."[21]

Eversource illustrates this in its System Planning Memorandum with an example of 70 MW_{AC} of installed solar generation producing 70 MW_{AC} of "Clear Sky Generation" on the minimum load day (blue line below), resulting in a calculated net load with reverse power flow (purple line).[22]

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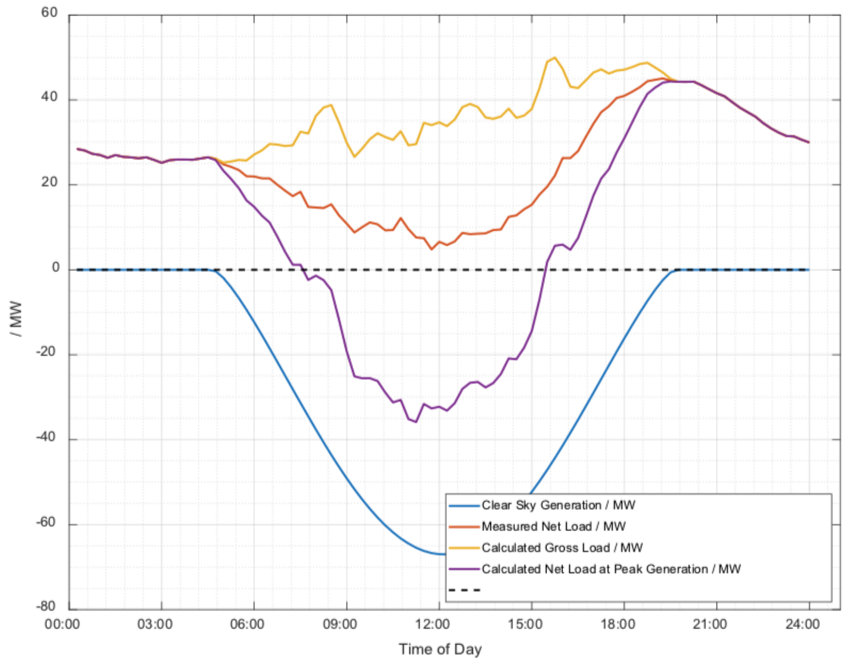
[19] California Public Utilities Commission, Docket A.19-08-13, Workpaper "SCE's Dependable Photovoltaic Generation Methodology", Exhibit No. SCE-02 Vol.04 Pt 02 Ch II Bk A, pp. 4-13

[20] Eversource D.P.U. 20-75 System Planning Memorandum, April 23, 2021, p. 10

[21] *Id.*, p. 20

[22] *Id.*, p. 11



Unitil also assumes solar DG output of 100% of AC nameplate rating during minimum loads, stating: "For minimum daytime load modeling of the system all existing (in-service) and future (Unitil planned or approved for install) distributed generation facilities shall be modeled at their full nameplate output."[23] NEA was unable to determine how National Grid models the impact of solar DG during periods of daytime minimum load.

This "worst case" approach proposed by Eversource and Unitil is unrealistic and could result in overstating DG impacts and identification of unnecessary upgrades. Manufacturers determine the DC nameplate ratings of solar DG panels when evaluated under Standard Test Conditions ("STC")[24], which rarely occur in real world conditions. It is more common for solar irradiance to be lower or cell temperatures to be higher than STC, meaning actual peak solar DG output is almost always less than 100% of its nameplate capacity rating, even during "clear sky" days.

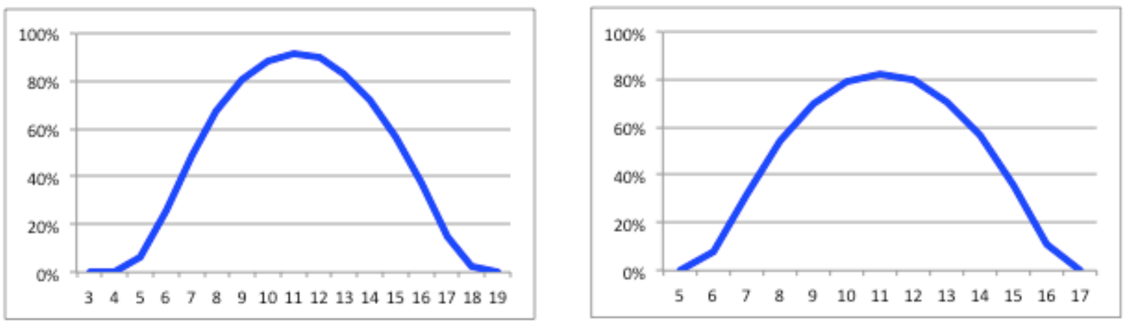
[23] Unitil System Planning Analysis Proposal, April 23, 2021, Attachment A, p. 15

[24] Standard Test Conditions (STC) = Cell temperature of 25°C; 1,000 Watts per square meter of solar irradiance; Air Mass Density = 1.5. Maximum solar panel output is less than its nameplate rating when cell temperature increases above, irradiance decreases below, or air mass increases above STC values.

To illustrate this reality, NEA modeled a 1.2 MW_{DC}, 1 MW_{AC} solar DG system in Amherst, MA using PVWatts[25], and identified the day of maximum AC system output each month in the spring and fall. Although the modeled system's output nearly reaches 100% of AC nameplate at 11am on March 23, the maximum output is 92% of AC nameplate in May and only 82% of AC nameplate in October as shown below.

Peak Solar DG System Output – Amherst, MA

(% of AC nameplate rating)



May 28	October 13
(POA irradiance = 1,079 W/m², Cell temp = 55°C at 11am)	(POA irradiance = 924 W/m², Cell temp = 47°C at 11am)

This demonstrates that solar DG "clear sky" output is not the same every month due to changes in irradiance and temperature, and almost always less than 100% of the AC nameplate rating. If the daytime minimum load for a circuit or substation in Amherst occurs in March, when our modeling indicates output could be near 100% of AC nameplate, it may be appropriate to assume maximum solar DG output at 100% of nameplate rating. If the daytime minimum load occurs in October, it is more appropriate to assume maximum solar DG output of only 82% of the AC nameplate rating.

NEA recommends that the Department require the EDCs to establish methodologies for determining the impact of solar DG during periods of daytime minimum load that are not based on 100% of AC nameplate rating, but rather are based on the actual maximum DG output in the month during which the daytime minimum load occurs.

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[25] https://pvwatts.nrel.gov/, standard module, fixed (open rack) array, 20° array tilt, 180° array azimuth, 14.08% system losses, 96% inverter efficiency, 1.2 DC/AC ratio

NEA also believes that Eversource is overstating the potential negative impact of energy storage in its Minimum Load Model, as it assumes all storage resources are **discharging** at 100% of their rated output during periods of daytime minimum load.[26] This is overly conservative and counterintuitive, as it is unlikely that all storage connected to a circuit or substation will be simultaneously operating in the same mode. It is also more likely that storage resources will be **charging** during times of low load and high solar DG output. Non-residential customers with stand-alone storage may be discharging during the day to minimize demand charges. However, residential and non-residential customers with solar paired with storage are most often charging during the day when the solar system is producing.[27]

Assuming that some or all of the storage resources are charging, not discharging, during periods of low daytime loads could materially impact Eversource's Minimum Load Model and potentially reduce the perceived need for DER-driven EPS upgrades. NEA is unclear how much of an impact this assumption currently has on Eversource's daytime minimum load calculations given the current penetrations of storage in its service territory, but it will certainly become more impactful as energy storage penetrations increase.

Given the uncertainty about its impact, NEA suggests that Eversource conduct a sensitivity analysis on the energy storage charging/discharging assumption. A sensitivity analysis would determine how much the magnitude and duration of reverse power flow would vary from a change in this assumption. For example, Eversource could select 3-5 circuits that currently have substantive residential and/or non-residential storage deployments, and run the reverse power flow analysis using assumptions of 0%, 50%, and 100% of the storage resources fully discharging during minimum load periods. The resulting reverse power flow values would inform the Department and stakeholders of the significance of this assumption.

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[26] Eversource D.P.U. 20-75 System Planning Memorandum, April 23, 2021, p. 10

[27] To qualify for the federal Investment Tax Credit ("ITC"), batteries in residential properties must only be charged by an on-site renewable energy system like solar. Non-residential properties are eligible for a credit under the ITC as long as the battery is charged by a renewable energy system more than 75% of the time. The exact value of the federal tax credit for batteries in non-residential properties depends on how frequently the battery is charged by a renewable energy system.

NEA recommends that the Department require Eversource to conduct a sensitivity analysis (e.g., 0/50/100% of residential, 0/50/100% of non-residential storage resources discharging during low daytime load periods) on a select number of circuits to determine the impact of this assumption.

NEA does not know how National Grid and Unitil account for energy storage in their daytime minimum load analyses, and also ***recommends that the Department require these EDCs to explain their methodology for accounting for energy storage in their models.***

Finally, ***NEA recommends that, after the Department receives the results of Eversource's sensitivity analysis and explanations of how all the EDCs account for energy storage in their analyses, the Department should identify the appropriate assumptions for energy storage operational modes (i.e., charging vs. discharging) during periods of low daytime loads, and require all three EDCs to use those assumptions.***

Meaningful Stakeholder Engagement

Of the three proposals, National Grid's includes the best approach to stakeholder engagement, including stakeholder input at several points in its proposed 4-stage planning process. Importantly, in Stage 1, Task 1, National Grid states that it: "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 … 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 [MA emissions reductions by 2050] … This could [include] a forecast of the future potential for solar and other DERs in Massachusetts broadly and on the Company EPS specifically … [E]ngagement 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(s) … 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 … they foresee adopting. Engagement with municipal and conservation groups will provide a better understanding of the general willingness of specific municipalities to allow or discourage DER development."[28]

The output from National Grid's proposed Stage 1, Task 1 is critically important for all EDCs, as it includes a summary of DER plans, issues, challenges, and opportunities across the Commonwealth. It also includes a set of forecast assumptions for subsequent DER scenario planning.

NEA believes it's important for all MA EDCs to have a shared understanding of existing and forecasted DER challenges and opportunities. ***NEA recommends that the Department require all EDCs to conduct the same stakeholder engagement as proposed by National Grid in Stage 1, Task 1, which will ensure that the EDCs are all incorporating a common set of Commonwealth-wide assumptions into their DER planning.***

National Grid's approach also includes stakeholder review of proposed alternatives and a review of the costs of all the alternatives. NEA considers this to be a reasonable level of stakeholder engagement.

Unitil's proposed approach to stakeholder engagement is also reasonable, with stakeholder participation at three stages of its proposed annual process. A first quarter meeting will include a review of DER forecasts and the circuits on which Unitil intends to conduct a detailed analysis. A second meeting in the third quarter of the year will cover the identified grid needs, the proposed system enhancements, and provide stakeholders an opportunity to suggest alternative solutions. The third stage of

[28] National Grid System Planning Analysis Proposal, April 23, 2021, pp. 10-11

stakeholder participation, in the fourth quarter of the year, will be the presentation of the final recommended solutions and costs.[29]

As previously stated, NEA has concerns about Eversource's proposed bifurcated planning approach and whether it will be able to identify optimal solutions to simultaneously address load-driven and DER-driven grid needs. Eversource rejects stakeholder input into its load-related analysis, stating, "It is important to note that the Company's Distribution upgrades that solely result from Eversource's base load forecast scenarios are otherwise included in the Company's Distribution Capital Plan and cannot be the subject of this stakeholder process, as decisions related to the base capital investments that are necessary to ensure the safe and reliable operation of the electric grid rest squarely with the EDCs. The EDCs must ensure the timely execution of these projects and therefore cannot subject the review, approval, or prioritization of base Distribution Capital projects to a stakeholder process."[30]

NEA is unclear why Eversource is so adamant that stakeholders be excluded from examining and understanding its Maximum Load Model, associated grid needs, and proposed solutions. In the context of the comprehensive distribution planning framework contemplated in this proceeding, if base load forecast scenarios are included in the EDCs' investment plans, these scenarios and assumptions must be available for stakeholder and Department review. ***NEA recommends that the Department require all EDCs to develop and conduct a stakeholder engagement process that allows stakeholders to holistically and comprehensively evaluate the EDCs' plans in order to identify multi-value solutions that simultaneously address load-driven and DER-driven grid needs.***

While NEA appreciates the EDCs' efforts to incorporate stakeholder input into the planning processes and agrees that stakeholder engagement is important, we are concerned about the number of meetings throughout the year and the ability or inability of resource-constrained stakeholders to fully participate. ***NEA recommends that the***

[29] Unitil System Planning Analysis Proposal, April 23, 2021, pp. 8-9

[30] Eversource D.P.U. 20-75 System Planning Memorandum, April 23, 2021, p. 26

Department work with the EDCs to synchronize the schedules so all EDC stakeholder engagement sessions, when possible, occur as a single session.

NEA also believes that a knowledgeable, skilled, and objective facilitator is critical for the success of the stakeholder working groups. Ideally, the facilitator will be a neutral party, either selected from within the Department or a third party, rather than selected and appointed by the EDCs. The facilitator should be knowledgeable about the subject matter and also have experience and skills in stakeholder engagement. The facilitator should ensure effective and neutral reporting of stakeholder group outcomes, including producing detailed minutes and reports with stakeholder input.[31]

National Grid agrees with this approach, stating, "The facilitator will be critical to managing the stakeholder process, and National Grid strongly supports a technical expert serving as the facilitator. The facilitator will need to manage the parties to consensus on a reasonable set of forecast assumptions to minimize impact on the planning schedule. Strong facilitation also will be needed to drive the planning process to completion, building on the consensus from the previous steps."[32]

NEA recommends that the Department select a knowledgeable, skilled, and objective facilitator to guide the stakeholder engagement processes.

While we recognize the need of the EDCs to make independent decisions related to the EPS to maintain safe, reliable operations, NEA believes that meaningful stakeholder engagement can result in more positive outcomes. To further increase the likelihood that the stakeholder engagement opportunities are meaningful for all participants, NEA also recommends the following:

- Utilities should be required to actively participate in the stakeholder process. When utilities participate only passively, stakeholders may not be informed of utility concerns and/or may feel that their concerns are not being critically

[31] Stanfield, Sky, and Stephanie Safdi. 2017. "Optimizing the Grid – A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources.", p. 25. Interstate Renewable Energy Council, December. https:// irecusa.org/publications/optimizing-the-grid-regulators-guide-to- hosting-capacity-analyses-for-distributed-energy-resources/

[32] National Grid Reply Comments on Straw Proposal, February 5, 2021, pp. 10-11

considered by the utilities. There should also be checks in place to ensure that utilities are meaningfully considering stakeholder insights and revising their methodologies where appropriate based on those insights.[33]

- Require the EDCs to provide slides or other presentation materials in advance of meetings and allow stakeholders to submit questions in advance to be addressed at the meetings.

- Require the EDCs to establish a joint website for MA integrated distribution planning information (such as reports, proposals, meeting minutes and presentations, other data) to serve as a general information hub for stakeholders. This could be similar to the New York Joint Utilities' site for Distributed System Implementation Plans (https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips)

- If / when in-person meetings resume at some time in the future, continue to offer virtual access as well.

Summary of Recommendations

In summary, NEA recommends that the Department:

- Adopt a planning process like the one proposed by National Grid, which would identify multi-value solutions that simultaneously address load-driven and DER-driven grid needs. At minimum, the Department should require Eversource to clarify how its proposed bifurcated planning process will identify such multi-value solutions.

- Require the EDCs to develop methodologies for quantifying the load-reducing benefits of DG during peak load periods based on actual DG system output data collected across the EDC service territories.

[33] Stanfield and Safdi, p. 26

- Require the EDCs to establish methodologies for determining the impact of solar DG during periods of daytime minimum load that are not based on 100% of AC nameplate rating, but are based on the maximum DG output in the month during which the daytime minimum load occurs.

- Require Eversource to conduct a sensitivity analysis (e.g., 0/50/100% of residential, 0/50/100% of non-residential storage resources discharging during low daytime load periods) on a select number of circuits to determine the impact of this assumption on its Minimum Load Model.

- Require National Grid and Unitil to explain how they account for energy storage in their daytime minimum load analyses.

- After receiving the results of Eversource's sensitivity analysis and explanations of how all the EDCs account for energy storage, identify the appropriate assumptions for energy storage operational modes (i.e., charging vs. discharging) during periods of low daytime loads, and require all three EDCs to use those assumptions.

- Require all EDCs to conduct the same stakeholder engagement as proposed by National Grid in Stage 1, Task 1, which will ensure that the EDCs are all incorporating a common set of Commonwealth-wide assumptions into their DER planning.

- Require all EDCs to develop and conduct a stakeholder engagement process that allows stakeholders to holistically and comprehensively evaluate the EDCs' plans in order to identify multi-value solutions that simultaneously address load-driven and DER-driven grid needs.

- Work with the EDCs to synchronize the schedules so all EDC stakeholder engagement sessions, when possible, occur as a single session.

- Select a knowledgeable, skilled, and objective facilitator to guide the stakeholder engagement processes.

- Require active utility participation in stakeholder meetings.

- Require the EDCs to provide slides or other presentation materials in advance of meetings and allow stakeholders to submit questions in advance to be addressed at the meetings.

- Require the EDCs to establish a joint website for MA integrated distribution planning to serve as a general information hub for stakeholders.

- If / when in-person meetings resume at some time in the future, continue to offer virtual access as well.

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1373210.2

ATTACHMENT A

Workpaper Title:

SCE's Dependable Photovoltaic Generation Methodology

Purpose

The purpose of this paper is to describe SCE's current methodology for calculating the dependable PV generation and explain the evolution of the calculation of the dependable PV generation.

Background

As PV systems are increasingly being used to generate power, SCE's reliance on their output must be quantified. Since the PV systems rely on environmental factors that are outside the control of SCE, there is a need to determine the amount of generation that can be reasonably relied upon when adverse conditions occur, such as cloud cover. These impacts are localized, and it is difficult to predict when or where they will occur. To limit the negative impacts of these variables on the ability for SCE to maintain the most reliable service to SCE customers, a series of studies have been performed to determine how much generation can be considered dependable, specifically when it impacts days with high loading.

Methodology

Methodology from Previous GRCs

In 2012, SCE performed a study to determine the maximum and minimum output of a typical PV system within the SCE service territory. This study incorporated 184 PV installations throughout the SCE service territory. The sample set provided a representation of different size PV installations and climate zones. The data gathered from these PV installations included output data during the months of June – September for years 2010 and 2011. The data was gathered during summer months because most of the SCE service territory is a summer peaking utility, as higher temperatures result in higher loading conditions. The average of the minimum output of the PV systems was determined to be ~18% at 12:15 PM. This study was utilized to develop SCE's 2015 General Rate Case Testimony.

This methodology has been referred to as the "Average of the Minimums" and has been refined over subsequent years by implementing additional data clean-up. In 2015, SCE re-evaluated the data used for the 2012 PV dependability study. SCE discovered some recorded data displaying zero generation output during times when PV would expect to be producing energy. SCE assumed that some of these systems had inaccuracies and removed them from the original 2012 study. This resulted in removing 18 PV systems from the original 184 leaving the 2015 study to analyze 166 total PV systems. The result of these changes provided a peak dependability of ~19%. This study was utilized to develop SCE's 2018 General Rate Case Testimony.

Methodology for 2021 GRC

As more information becomes available, SCE continues to refine the PV dependability methodology used for Distribution & Sub-Transmission system planning. Over the years, SCE has moved away from the "Average of the Minimums" methodology to utilizing a percentile-based approach. The current methodology utilizes data from 860 PV systems spread over the entire SCE territory. This data comes from customers that participate in the California Solar Initiative (CSI) program that selected the Performance Based Incentive (PBI) and provide separate solar generation data to SCE. The data was analyzed during summer months from 2014 to 2015. Below are some of the key differences between the PV dependability methodology utilized in the 2018 GRC and SCE's current methodology utilized to develop the 2021 GRC.

1. Expanded Data Set
   SCE has increased the amount of systems included in its PV Dependability methodology from 187 systems to 860 systems.

2. Enhanced Geographical Representation
   Instead of producing a single curve used for the entire SCE territory, the current methodology develops 8 curves representing each of SCE's planning regions to better represent geographical differences in PV output. Each planning region is mapped a set of unique meter data customers and the data for each region was used to develop the specific regional curve.

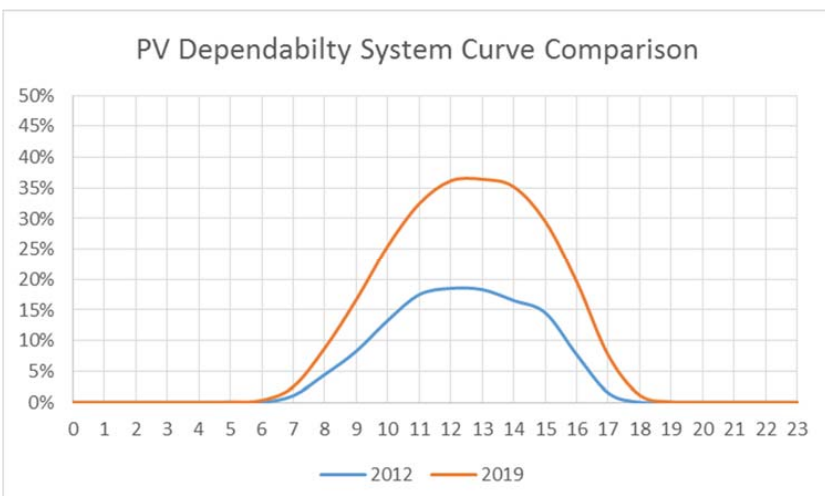
3. Additional Data Cleansing
   In the 2018 GRC, SCE removed 18 systems with values that appeared erroneous, but did not remove zero values from remaining 166 systems. In the current study, all zero values and values greater than 101% were excluded.

4. Profile Shape Development

   As described above, SCE has moved away from an average of the minimums toward a more standard statistical methodology by utilizing a percentile approach. The 10^{th} percentile was selected to represent the PV output that can be reliably depended on to serve load 90% of the time during peak summer months.

Utilizing these improvements, SCE developed eight regional dependability curves. The 10^{th} percentile for each 15-minute interval was calculated from the cleansed data to generate a 24-hour curve for each planning region. The PV profile shapes that were developed for each region can be found in Appendix A. The SCE territory shape is calculated by using all data from all regions and only included for comparison between the curves used in the 2018 filing versus the 2021 filing (See Figure 1), each respective curve is labeled "2012" and "2019" respectively); the SCE territory curve was not used for planning purposes. Utilizing a 10^{th} percentile approach provided a dependability of ~36% at 12:00 PM. This is an increase of about 17% at noon from the approach used to develop the 2018 GRC.

Figure 1. PV Dependability System Curve Comparison



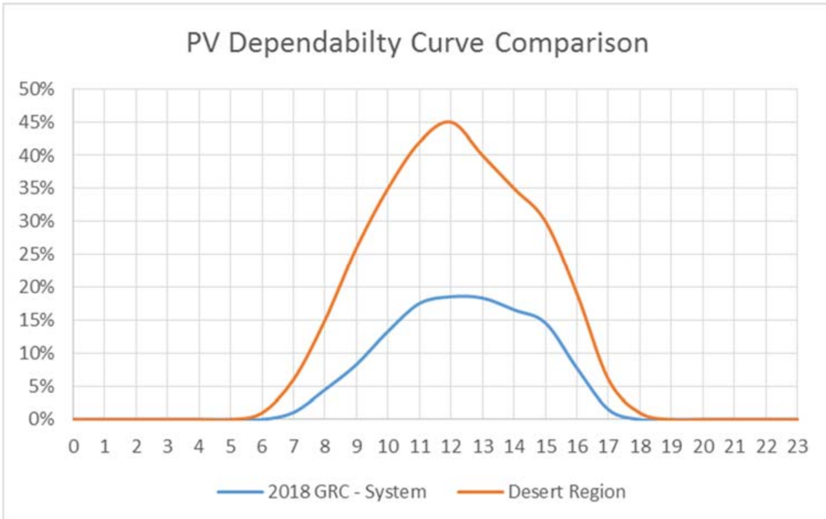
Conclusion

SCE continues to evaluate and enhance its PV dependability methodology as more information becomes available. The methodology has significantly evolved from 2015 GRC to

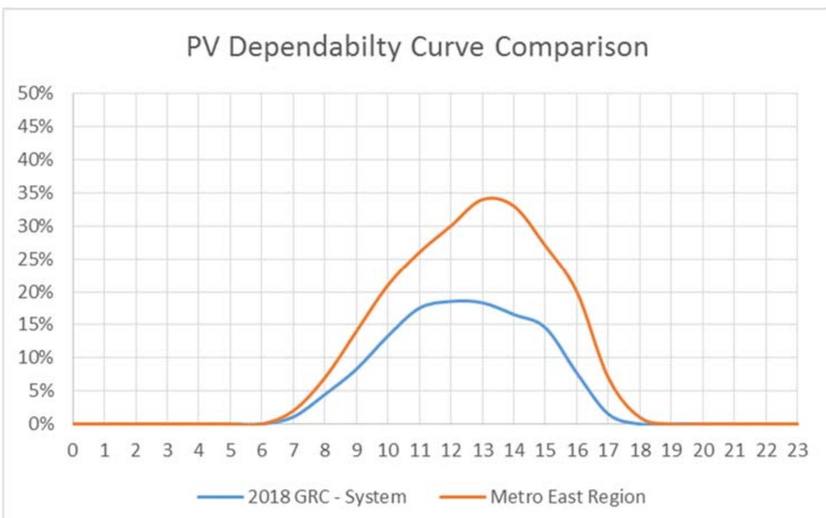
2021 GRC. The previous methodologies used a single system curve where the current methodology deploys a regional curve, which more closely resembles individual system performance. In the current study, the cleansing effort removed data that contained values ≤0% & ≥101% of nameplate. Finally, the shift to a 10th percentile analysis has resulted in a more standard statistical method to better represent the data distribution. SCE will continue to review its methodology and make improvements where appropriate.

Appendix

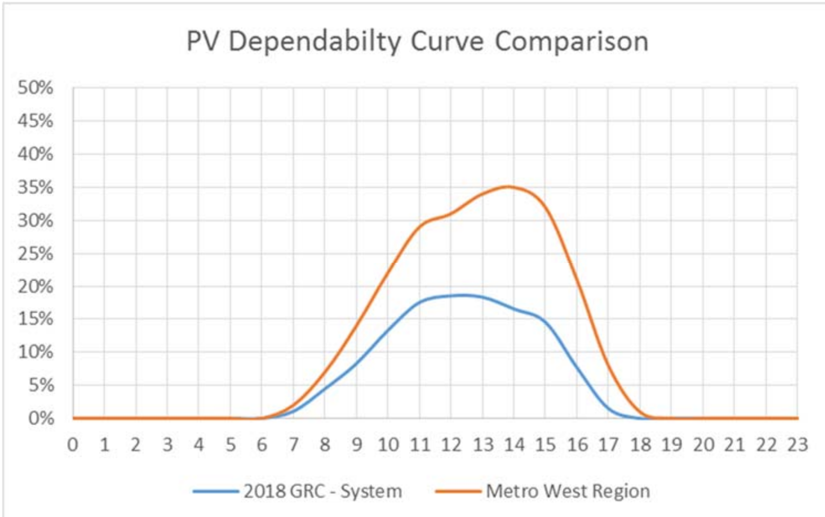
Desert Region Profile



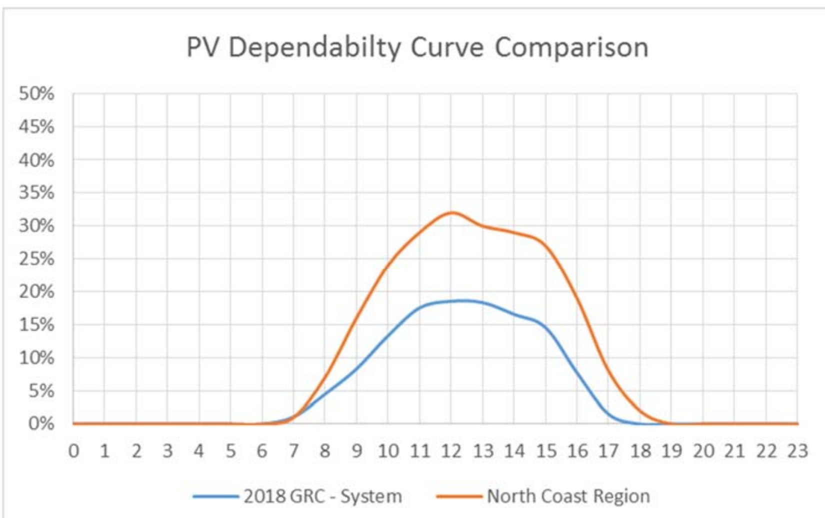
Metro East Region Profile



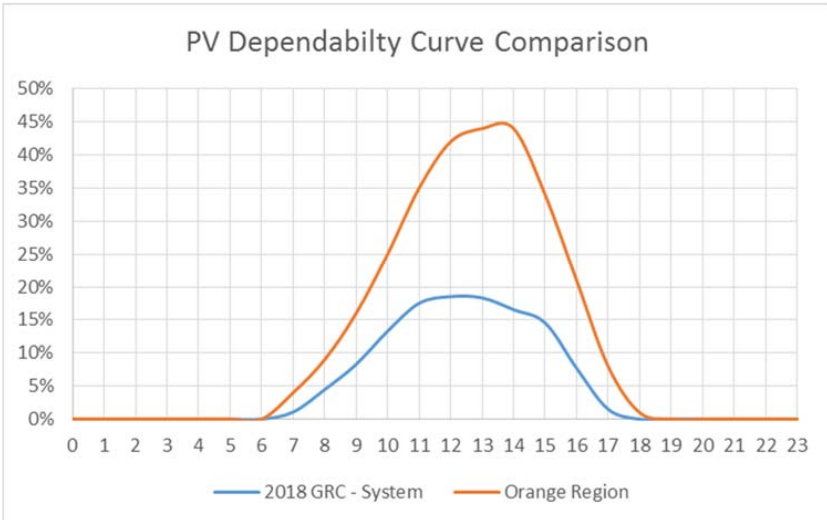
Metro West Region Profile



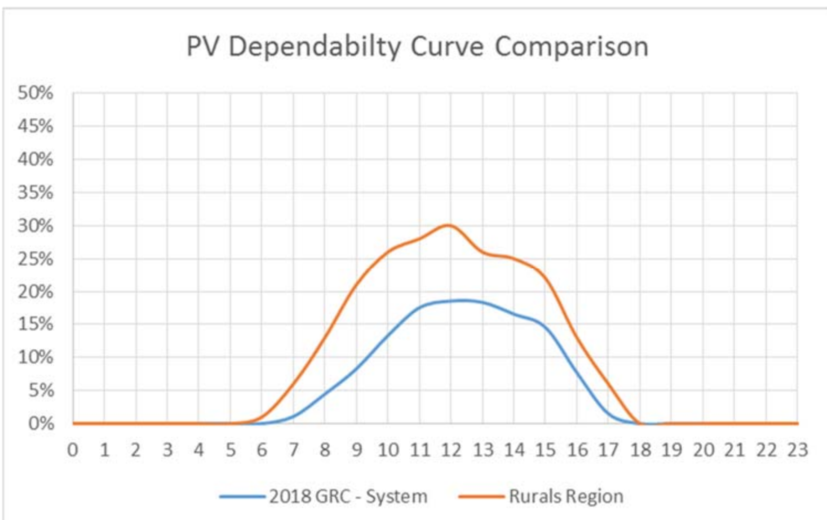
North Coast Region Profile



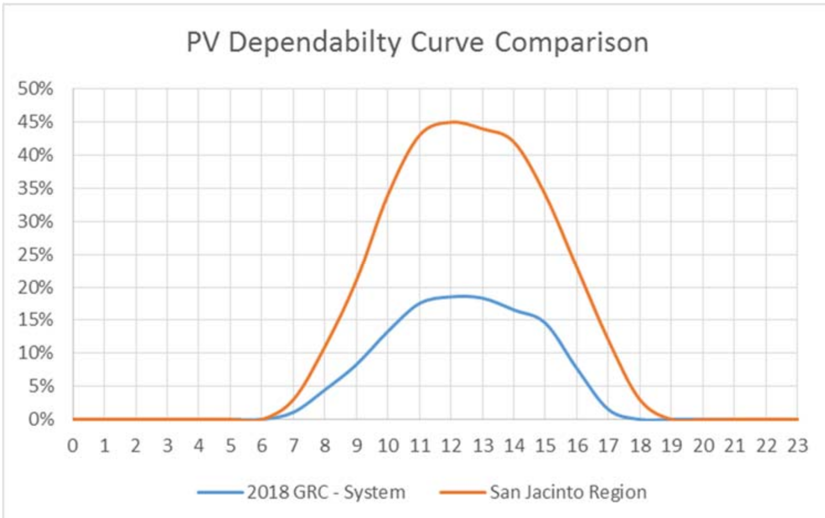
Orange Region Profile



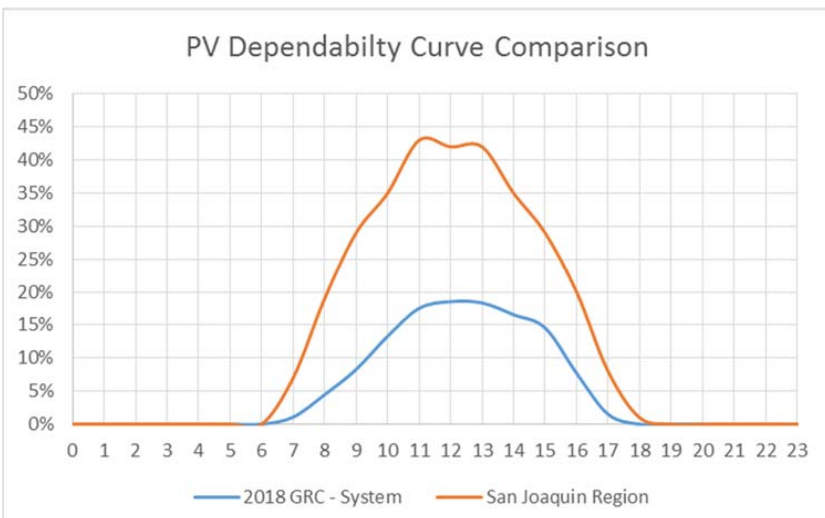
Rurals Region Profile



San Jacinto Region Profile



San Joaquin Region Profile



Regional Profile Hourly Values

10th Percentile Dependable PV Curves by Region by hour

Hour	Desert Region	Metro East Region	Metro West Region	North Coast Region	Orange Region	Rurals Region	San Jacinto Region	San Joaquin Region
0	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%
6	1%	0%	0%	0%	0%	1%	0%	0%
7	6%	2%	2%	1%	4%	6%	3%	7%
8	15%	7%	7%	7%	9%	13%	11%	19%
9	26%	14%	14%	16%	16%	21%	21%	29%
10	35%	21%	22%	24%	25%	26%	34%	35%
11	42%	26%	29%	29%	35%	28%	43%	43%
12	45%	30%	31%	32%	42%	30%	45%	42%
13	40%	34%	34%	30%	44%	26%	44%	42%
14	35%	33%	35%	29%	44%	25%	42%	35%
15	30%	27%	32%	27%	34%	22%	34%	29%
16	19%	20%	21%	19%	21%	13%	23%	20%
17	6%	7%	8%	8%	8%	6%	12%	8%
18	1%	1%	1%	2%	1%	0%	3%	1%
19	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%