August 2, 2022

VIA EMAIL

California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Rulemaking 21-06-017 Data Portals Workshop

To the CPUC Energy Division,

The Center for Biological Diversity, Clean Coalition, 350 Bay Area, the Climate Center and Synergistic Solutions submit this letter in response to the July 26, 2022 Data Portals Workshop in Rulemaking 21-06-017.

The Commission has recognized procedural justice in its Environmental and Social Justice ("ESJ") Action Plan, and the need to "maintain fairness and transparency of the processes by which decisions are made."[1] At the May 3, 2022 kickoff workshop for Track 2, stakeholders voiced concern that the workshop format of soliciting off-the-record comments hinders efforts to maintain such transparency, and expressed the need for a more formal commenting mechanism. A follow up submission to the Commission noted that the process is "informal and consultant-driven, with very limited on-the-record stakeholder participation . . . For example, proposals and presentations for this workshop are available on a Gridworks website, but none of this work has been made a part of the record of this proceeding."[2]

The same issue applies to this and other tracks of the proceeding. In order to ensure that the Commission, all parties, workshop participants, Energy Division, and its consultants adequately understand and have an opportunity to respond to each other's comments, the Commission must ensure adequate opportunities for formal comment to establish a thorough record for the proceeding. In this instance, although stakeholders have the opportunity to comment on the workshop via a google form, that form is limited, with only the last question focusing on the actual substance of discussions at the workshop. The one-week timeframe in which to digest this highly technical material has also proven a barrier to effective participation. Nevertheless, in order to ensure transparency and meet the procedural justice elements of the ESJ Action Plan, we respectfully request that the Energy Division Staff Report on Data Portals include this and other comments received, whether through the google form or otherwise, along with responses to each of the comments. In addition, we offer the following four comments.

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[1] Environmental and Social Justice Action Plan v. 2.0 at 70.

[2] California Alliance for Community Energy, Center for Biological Diversity, Center for Community Energy, Grid Alternatives, Local Clean Energy Alliance, Reimagine Power, Synergistic Solutions, The Climate Center, Vote Solar, and Wild Tree Foundation, Summary and Key Take-aways: CPUC Kick-off Workshop re: Evaluating Alternative DSO Models (R.21-06-017), May 3, 2022.

I. Anticipation of a High DER Future Requires Consideration of Disadvantaged Community ("DAC") Needs.

In opening comments at the workshop, Energy Division clarified that this proceeding does not intend to increase or decrease the target for the number of DERs deployed, but rather to focus on the anticipation of a high-DER future. This objective involves ensuring that planning tools and processes are in place to facilitate rapid integration of DERs as we achieve a high DER future. As noted in our prior comments throughout this proceeding, it is important for this planning process to include the identification and integration of DAC resident needs into expectations of future DER growth so that the Commission can tailor and proactively *plan* for DER deployment strategies to effectively meet those needs. Otherwise, there is a likely and foreseeable risk that DAC needs will not be addressed in a high DER future, precluding our ability to meet California's SB 100 and other climate and equity targets.

II. The Commission Should Utilize Accurate Data to Highlight the Benefits of DERs.

It is critical for the Commission to remedy the Integration Capacity Analysis ("ICA") load analysis, which is subject to significant inaccuracies due to the lack of, and need for validation and quality assurance/quality control.[3] Kevala's presentation concluded with the key takeaway that DERs and load management strategies will be key in assuring distribution capacity over the mid- and long-term planning horizon. Accurate data can also evaluate the potential line losses associated with transmission that DERs avoid, and this information should be readily available and accessible to the public. This is important because SB 100's narrow focus on retail sales alone means that even achieving our 100% renewables target may still include fossil fuel generation to meet transmission losses from the grid, which are not considered retail sales. In addition to conveying a more accurate picture of the benefits of load management, the data can also highlight one significant benefit of DERs to cure the inefficiencies associated with transmission to the benefit of DAC residents close to fossil fuel infrastructure. In this regard, pursuant to the Commission's direction, all of the IOUs must include relevant information on their transmission lines in the data portals.[4]

It is also important for the Commission to consider other benefits of DERs, including non-energy benefits ("NEBs") and the full suite of avoided *social* costs, including decreased local air pollution in DACs. Much of this data is already publicly available, such as certain analyses of backup diesel generators' impacts in DACs and avoided internal combustion engine vehicle emissions.[5] Including such data in the data portals could potentially unlock other sources

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[3] *See* R.14-08-013 Comments of the Interstate Renewable Energy Council on Refinements to the Integration Capacity Analysis, Attachment 1 (August 1, 2019).

[4] *Id.* Resolution E-4414 at 21-22; (ordering the publication of transmission system maps); and R.14-08-013 ALJ's December 17, 2018 Ruling on Confidentiality, at 13-15 (ordering the publication of transmission system maps).

[5] *See e.g.* M.Cubed Diesel Back-Up Generator Population Grows Rapidly in the Bay Area and Southern California, *available at* https://www.bloomenergy.com/resource/new-study-shows-a-rapid-increase-of-diesel-fueled-backup-generators-across-california/ (estimating that the extra pollution from backup generators may trigger upwards of $31.8 million in annual health costs in the Bay Area and $103.9

of funding to serve DAC residents, such as funding geared towards the protection of public health. The California Energy Commission is beginning work on developing and quantifying NEBs.[6] Although this NEBs dataset is not yet formal, it is important for the work on the data portals to be forward looking. The design of data portals should allow for efficient integration of these and other datasets as they become available in the future, and the data portals themselves should include the relevant publicly available data.

III. The Commission Should Include the Following Modifications to the ICA Maps.

In addition to the modifications to the ICA data detailed above (the need for load analysis validation and adequate inclusion of transmission system data), we are also concerned with the sufficiency of the current ICA data, in particular for SCE's service territory as detailed in the recent letter to Energy Division from Shute, Mihaly and Weinberger and the Interstate Renewable Energy Council (attached as Attachment A). We also offer the following additional recommendations to improve ICA data.

1. Although the ICA maps indicate which violation(s) (thermal, voltage, distribution protection, or operational flexibility) is(are) limiting the integration of distributed generation, not all of this data is accessible via an application programming interface ("API"). The Commission must enable the public to search or query the ICA data in order to make any functional use or policy decisions. Line by line information alone is informative, but practically limiting. The Commission must ensure that an API can access the many load profiles and criteria volition values for each line segment, so that sophisticated developers and policy makers can fully utilize the ICA data.

2. Each IOU's interactive ICA map should be widely available to the public without the need to sign in or request access. Currently, for PG&E's ICA map, it is necessary to create login credentials before beginning use. To use SDG&E's ICA map, a user needs to request access, which often requires multiple days of waiting before a response, and then create login credentials. Furthermore, this access is revoked after a certain period. SCE's interactive ICA map, on the other hand, provides immediate access without the need to register or create login credentials.

3. Each of the IOU's interactive ICA maps should provide an easy way to download the ICA spatial data in multiple, commonly used formats (for instance, GEarth, geodatabases). So far, PG&E and SDG&E allow users to download just ICA geodatabases, but only after users create login credentials and/or request access, whereas SCE allows users to download KML, shapefile, XML and GeoJSON formats of ICA spatial data through its interactive ICA map.

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million in South Coast communities, due to increases in mortalities, heart attacks, hospital visits and other adverse consequences, particularly in vulnerable communities).

[6] *See e.g.* Scoping Order for the 2022 Integrated Energy Policy Report Update (Establishing a Framework to Center Equity and Environmental Justice Throughout CEC Efforts).

4. Data validation needs to be conducted on a feeder-by-feeder basis throughout each of the IOU-service territories, particularly given the importance of ICA in the interconnection process.

5. Energy Division should establish timelines and accountability metrics for providing ICA data, including updates and corrections.

IV. Community Engagement and Partnerships Can Happen Concurrently with the Development of a Framework that Centers Community Needs.

We emphasize that there is no need to wait for determination of specific community needs, or the conclusion of community engagement and partnership efforts, prior to developing a framework and related data portals centered on consideration of those needs. In other words, it is possible to develop a framework that addresses the recommendations described above, and can easily incorporate additional community needs once identified. For instance, in regards to Track 2, this proceeding's working group process can evaluate which DSO models allow for deployment of DERs to meet community needs and modify those that do not to include meeting community needs. Similarly here, the Commission should design the data portals to ensure access to all essential information needed by participants, and then modify them on an ongoing basis as needed to support DER siting and planning to meet community needs.

Finally, the Commission should also design the data portals to be more accessible by the general public in anticipation of their use by entities outside of their historical users. The Commission should collaborate with historical users (community choice aggregators, public agencies, trade organizations and developers) to ensure that data portals include appropriate data for market entities to create a customer-friendly and intuitive data access experience. This also requires streamlining datasets, for instance, incorporating standardized and consistent data set headers and terminology amongst IOUs.[7]

Sincerely,

Roger Lin
Center for Biological Diversity

Ben Schwartz
Clean Coalition

Claire Broome
350 Bay Area

Kurt Johnson
The Climate Center

Robert Perry
Synergistic Solutions

[7] *Supra*, note 3; D. 17-09-026 at 60 ("The IOUs shall continue to standardize a common mapping structure and mapping functionality"), but, for instance, the IOUs do not use standardized ICA Operational Flexibility Criteria Violation values.

ATTACHMENT A

SHUTE, MIHALY & WEINBERGER LLP

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July 29, 2022

Via Electronic Mail Only

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Re: Addressing Potential Issues with Southern California Edison's Integration Capacity Analysis

Dear Justin and Gabe:

On behalf of the Interstate Renewable Energy Council, Inc. (IREC), I am writing to formally alert you to IREC's concerns about the system-wide refresh of the Integration Capacity Analysis (ICA) that Southern California Edison (SCE) is conducting. The current results, and the lack of explanation as to whether they are reliable, is deeply concerning and is going to greatly impact the interconnection process in SCE's territory. IREC believes this is an urgent issue that requires the Commission's immediate attention.

Background

On February 14, 2022, IREC submitted its fifth data request to SCE requesting, amongst other things, the full ICA data, including the criteria violation values for all locations in SCE's territory. IREC sought this data in order to support analysis that IREC was seeking to conduct for phase II of the Rule 21 proceeding (R. 17-07-007). This request was necessary because SCE's application programming interface (API) does not provide access to the full ICA data.

On March 15, 2022, SCE uploaded the requested data to a server for IREC to access. IREC's consultant, Cadeo Group LLC (Cadeo), began to analyze the data and put together a table which summarized the aggregate results in terms of the number of nodes where there was either a high amount of capacity (above 10,000 kW) or no capacity (0 kW) for each of the ICA criteria violations. On May 19, 2022, IREC sent its sixth data request to SCE with some questions related to the data provided. Because IREC was looking to rely on the ICA data provided in the Phase II proceeding, IREC asked SCE to confirm whether certain aggregated results were consistent with what SCE would anticipate on its system.

On June 3, 2022, SCE responded to IREC's data request. In that response, SCE indicated that it was unable to recreate the table IREC included without "extensive rework," and instead offered a new table using "the latest ICA results." This table showed dramatically different results from what IREC had calculated using the March 2022 ICA data. SCE indicated that they were conducting an "extensive system-wide refresh" of the ICA and that the new results incorporated some level of the system-wide refresh. SCE indicated that they were not able to "ascertain whether the values presented are 'consistent with an SCE expectation level.'" SCE also noted that where the values were not close between IREC's table and that of SCE, "an in-depth evaluation will be required to determine reasons for significant differences" and indicated they had "commenced activities to evaluate results and derive levels of expectations" for the items in the table.

IREC reviewed SCE's updated table and immediately became concerned about the dramatically different values being reported. In some cases, the results changed by as much as 58%. Most crucially, the number of nodes where there would be 0 kW of capacity under the ICA-OpFlex rose from 60% to 88%. IREC would expect that the ICA data would change incrementally between March and June 2022, but the comparison between the March and June 2022 data does not comport with the scale of interconnections or distribution system changes that one could possibly expect in such a short timeframe.

In light of these concerns, IREC reached out to SCE to request a meeting to discuss the results. IREC shared the data response with the Energy Division staff overseeing Rule 21 and with the consultants at Kevala and Verdant that are supporting the Energy Division's work in the High DER docket. IREC invited both the Energy Division and consultants to participate in the call with SCE.

On July 12, 2022, IREC hosted a call with SCE and Jose Aliaga-Caro from the Energy Division to discuss the ICA results. SCE reported that they had not yet conducted any evaluation to determine the reasons for the dramatic difference in results, and indicated that they did not have a concrete plan for when or how that evaluation would be conducted. SCE explained that as part of the system-wide refresh there were a number of changes being made to the ICA data and method of running the analysis, but they could not pinpoint which of those changes might have resulted in such a dramatic difference in the results.

On July 20, 2022, another call was held between IREC, SCE, and Justin Regnier from the Energy Division. In that call SCE indicated that their intent was to continue to conduct the system-wide refresh despite the Company's lack of understanding of the results. SCE could not identify a specific target date for completion beyond sometime in September 2022. SCE indicated that at some point in October 2022 a data dashboard would be completed and that only after that dashboard is up and running do they intend to conduct the in-depth investigation into the discrepancies between the ICA results. SCE indicated that they did not have any specific plans to notify ICA users or interconnection customers about the potential questions associated with the new ICA values.

SCE also noted that they cannot be certain that they applied the same methodology that Cadeo used in creating their updated table. To resolve this question, on July 22, 2022, IREC sent SCE an explanation of the method used by Cadeo to produce the table. If different methodologies were used, it is possible this could resolve the questions, but until we hear otherwise from SCE it appears to be appropriate to assume the tables were developed using consistent methods.

IREC has included each of the data requests, responses, and a table comparing the March and June results as attachments to this letter. The table shows the difference for each criteria between the March and June results and is a useful way of understanding how significant the changes really are. IREC is not including the .csv files and underlying ICA data provided in the data responses (together this is a large amount of data and cannot be easily transmit via email), but the Energy Division should be able to request that data directly from SCE.

Implications and Request for Commission Action

On June 28, 2022, the Commission issued Resolution E-5172, which incorporates the ICA results into the Rule 21 screening process. The Resolution requires the utilities to implement the changes adopted in the Resolution 45 days after approval of the Resolution (August 8, 2022). After that date, all projects subject to Screen M of Rule 21 will be screened using the ICA results except when ICA results are not available.

Projects below 30 kVA, and qualifying non-export projects, skip Screen M. The newly updated Screen M requires that projects be below 90% of the ICA-Operational Flexibility (ICA-OpFlex).

If SCE uses the refreshed results, projects subject to Screen M will fail Fast Track on at least 88% of the nodes in SCE's territory (note that SCE has yet to complete the refresh and it is possible that an even greater number of nodes will ultimately show 0 kW of hosting capacity). In addition to raising alarms due to the sheer number of projects that will have to proceed to Supplemental Review, it is entirely unclear if the ICA results are accurate. While it may be the case that the newly refreshed results are accurate, it is deeply troubling that SCE is unable to explain why they changed significantly. Since there is no known explanation for the differences (and the results are significantly different than that of the other IOUs), it is reasonable to be concerned that these results may not be accurate.[1]

Using ICA data that SCE cannot explain, and which will result in the vast majority of projects subject to Screen M failing fast track, is going to have significant and immediate impacts on interconnection customers. Some projects will be subject to a $2,500 supplemental review fee, and ratepayers will bear the cost of the supplemental review for projects that are not subject to the fee. Rule 21 establishes a 20-business-day timeframe for supplemental review, and this does not include the steps required between fast track and the commencement of that review.

IREC has reviewed SCE's most recent Rule 21 timeline report and it is clear that SCE is not meeting the fast track (initial review) or supplemental review timelines for a number of projects today. It is not clear what sending many more projects to supplemental review will do to SCE's ability to meet timelines that it is already failing to meet in some cases. This additional time (and associated supplemental review fees) creates real costs for interconnection customers and the Commission should want to ensure that these projects are appropriately being subject to this additional review. It is

[1] Working with the National Renewable Energy Laboratory, IREC published a report on best practices for hosting capacity analysis data validation. One of the key recommendations of this report, as well as the Quanta review of the ICA Data Validation Plans, is that utilities should validate results before they are published to customers. This includes performing extra validation efforts when software updates or process changes are implemented. The report can be downloaded at https://irecusa.org/resources/hosting-capacity-analysis-data-validation/, and for ease of reference is attached to this letter.

also not clear how SCE will actually review these projects in supplemental review in light of the questions regarding the ICA results, and in particular, the operational flexibility criteria violations.

IREC urges the Commission to take immediate steps to require SCE to investigate the reasons for the substantial change in ICA values. If that investigation reveals errors in the analysis, the Commission should require SCE to fix those errors immediately. In addition, the Commission should immediately notify ICA users and interconnection customers that there is uncertainty about the ICA results so that there is transparency about the risks of relying on the ICA to determine potential interconnection locations.

Sincerely,

SHUTE, MIHALY & WEINBERGER LLP

Yochi Zakai

Yochanan Zakai

cc: Sky C. Stanfield
Stacy Lee
Radina Valova
Robert Peterson
Taaru Chawla

Attachments:

Comparison of SCE Results Between March 2022 and June 2022, July 20, 2022
IREC 4th Data Request to SCE, November 29, 2021
SCE Response to IREC 4th Data Request, December 12-29, 2022
IREC 5th Data Request to SCE, February 14, 2022
SCE Response to IREC 5th Data Request, March 2-3, 2022
IREC 6th Data Request to SCE, May 19, 2022
SCE Response to IREC 6th Data Request, June 3, 2022
NREL and IREC Data Validation for Hosting Capacity Analysis, April 13, 2022

ICA Criteria	High Capacity (Min Capacity > 10,000 kW)			High Capacity (Min Capacity > 10,000 kW)			No Capacity (Min Capacity = 0 kW)			No Capacity (Min Capacity = 0 kW)		
	Max Load Day			Min Load Day			Max Load Day			Min Load Day		
	March	June	Difference	March	June	Difference	March	June	Difference	March	June	Difference
Generation - Protection	71	85	-14	71	85	-14	25	13	12	25	13	12
Generation - Operational Flexibility	0	3	-3	0	0	0	38	84	-46	29	61	-32
Generation - Steady State Voltage	18	76	-58	19	67	-48	17	30	-13	11	17	-6
Generation - Voltage Variation	30	48	-18	31	47	-16	1	0	1	1	0	1
Generation - Thermal	15	27	-12	15	26	-11	2	1	1	2	1	1
Generation - Uniform Operational Flexibility	0	2	-2	0	0	0	60	88	-28	52	69	-17
Generation - Uniform Static Grid	5	18	-13	5	17	-12	38	38	0	32	26	6
Solar PV- Uniform Operational Flexibility	0	NP	#VALUE!	0	NP	#VALUE!	40	NP	#VALUE!	36	NP	#VALUE!
Solar PV- Uniform Static Grid	2	NP	#VALUE!	2	NP	#VALUE!	31	NP	#VALUE!	28	NP	#VALUE!
Load - Voltage Variation	0	42	-42	0	41	-41	25	0	25	27	0	27
Load - Thermal	0	12	-12	1	17	-16	70	63	7	51	37	14
Load - Uniform	0	9	-9	1	12	-11	77	74	3	58	47	11

Note that in the June results there are more than 100% of the feeders for the steady state voltage criteria on the max load days.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S FOURTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

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DATED: November 29, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S FOURTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

To:

Kathryn Enright
Southern California Edison
Kathryn.Enright@sce.com

Alexa Mullarky
Southern California Edison
Alexa.J.Mullarky@sce.com

Pursuant to Article 10 of the California Public Utilities Commission's Rules of Practice and Procedure, the Interstate Renewable Energy Council, Inc. (IREC) hereby serves its Fourth Data Request upon Southern California Edison (SCE) in the above-referenced proceeding.

IREC requests a complete response to this data request as soon as possible, but in no event later than the close of business on December 13, 2021. To the extent any data requests are objected to, IREC requests that any and all objections be specified and the nature of those objections be fully articulated on or before December 8, 2021.

The responses should be sent via e-mail to the following:

Sky C. Stanfield
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Stacy Lee
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Slee@smwlaw.com

I. GENERAL INSTRUCTIONS

A. In responding to the following requests, please set forth the request and then state SCE's response.

B. Each request should be deemed continuing in nature. Thus, if SCE acquires additional information regarding any such request, SCE should supplement its response as soon as possible following its receipt of such additional information.

C. In the event that SCE objects to any request on the ground that the information sought is irrelevant or immaterial to any issue in the above-captioned matter, please state the specific basis for such objection, including the basis for any contention that such information is not or does not appear "reasonably calculated to lead to the discovery of admissible evidence . . . ." CPUC Rules of Practice and Procedure, Rule 10.1.

D. In the event that SCE asserts any privilege against the release of any information sought in any request, please specify the privilege asserted and explain the basis of its assertion. In addition, with respect to any document asserted to be privileged, please identify such document.

E. In the event that SCE asserts that any information or document sought is public information or is publicly available, please specify:

   1. The title of the document or other source in which the information may be found;

   2. The specific page and line number or other precise reference to where the information can be found; and

   3. Where the document or other source containing the information can be found.

F. In the event that SCE asserts that any requested information is not available in the form requested, please disclose the following:

   1. In what form the information currently exists, including identifying documents;

   2. Whether it is possible under any circumstances (and, if so, what circumstances) for SCE to provide the information in the form requested;

   3. The procedures or calculation necessary to provide the information in the form requested;

   4. The length of time (in hours and days) necessary for SCE to prepare the information in the form requested; and

   5. The earliest dates, time period and location that representatives of IREC may inspect SCE's files, records, or documents in which the requested information currently exist.

G. Terms.

1. The terms “documents,” “working papers,” “studies,” “reports,” “records,” “surveys,” “examinations,” “research,” “reviews,” “summaries,” “papers,” “notes,” “memos,” and “analysis” are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

2. The terms “data,” “figures,” “information,” “assumptions,” “facts,” “statistics,” “measurements,” “findings,” and “results” are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

3. “SCE” refers to Southern California Edison.

4. Capitalized terms shall have the same meaning as defined in Rule 21, section C (Definitions).

5. To the extent any other terms are unclear, please assume a reasonable meaning for the term, state the assumed meaning, and respond to the discovery request using the assumed meaning of the term.

H. Identify for each response the person(s) sponsoring the response and corresponding job title(s).

II. DATA REQUESTS

1. Please provide a sortable spreadsheet including all Non-Exporting projects that have applied to interconnect under Rule 21 in SCE’s territory in the last five years, with the following information about each project:

    a. Project ID,
    b. Project Status (e.g., application accepted, implementation, withdrawn, etc.),
    c. Technology Type (e.g. storage, solar, etc.),
    d. Customer Rate Class,
    e. Use case (e.g., backup power, demand charge reduction, etc.),
    f. Type of export control used (e.g., Reverse Power Protection, Minimum Power Protection, Certified Non-Islanding Protection, Relative Generating Facility Rating, Inadvertent Export, or Inadvertent Export Utilizing UL-1741 or UL-1741),
    g. Size (total proposed generating capacity in kW, broken out by technology if includes more than one type),
    h. Date Application Received,
    i. Upgrades required? (If yes, identify type of upgrade),
    j. Upgrade required due to load reduction? (yes or no), and
    k. If completed, operation date.

2. In the February 1, 2019 Response of Southern California Edison Company to Administrative Law Judge's Ruling Directing Responses to Questions on Working Group Two Report, SCE stated: "While SCE believes that the aforementioned safety and reliability issues would result if Non-Exporting projects of all sizes continue to be allowed to bypass screens—i.e., if Screen I is not moved to Rule 21's technical framework overview—SCE does not, at this time, have sufficient information available to answer when, or with what frequency, SCE could begin to experience overvoltage conditions." With respect to this statement, please answer the following questions:

    a. Does SCE now have sufficient information available to answer when, or with what frequency, SCE could begin to experience overvoltage or other adverse conditions from the interconnection of Non-Exporting customers? If so, please identify the expected frequency of occurrence (i.e., number of projects a year) and the magnitude of associated upgrade costs you anticipate as a result (in dollars per year). Please also explain the basis for SCE's belief that this will occur and how the company identified the number of events and magnitude of the upgrade costs.
    b. If SCE does not have sufficient information to answer when or with what frequency it would begin to experience safety and reliability issues if Non-Exporting projects continue to skip Screen I, what is the basis for SCE's expressed belief that this will result?

3. Under Rule 21, projects that qualify as Non-Exporting under Screen I are able to skip all subsequent screens, including Screen M. In light of this, if a Non-Exporting project were to trigger the need for an upgrade, how would the triggering conditions be identified today?

4. At page 54, the Working Group Two Report states that "[i]n the event load changes (i.e., increases or decreases) subsequent to that interconnection, the utility has several approaches to cost allocation for the associated costs. If the change falls under Rules 15 and 16, which cover new line extensions, cost responsibility is determined by the customer's obligations under the line extension contracts. If the change is not covered by Rule 15 and 16, such as for load increases or decreases that emerge in forecasted load, the utility would plan for necessary upgrades, seek approval of those costs from the Commission through a general rate case during the utilities' filing period, and, if approved, collect the costs of the upgrade from all customers." With respect to this language, please provide a sortable spreadsheet which identifies all necessary upgrades and costs associated with load reduction caused by individual Non-Exporting projects in the last five years, including:

    a. Project ID (please use the same ID as provided in response to Question 1),
    b. Manner in which the upgrade was identified (i.e., through the Rule 21 review process or other means. If other, please describe.),

c. Reason upgrade needed (e.g. protection, voltage, etc.),
d. The type of upgrade (e.g. transformer replacement, etc.),
e. The cost of the upgrade,
f. Whether the upgrade cost was covered by Electric Rules 15 or 16, and if so, which section or subsection,
g. Whether the upgrade cost was instead approved through a general rate case, and
h. Party responsible for cost (e.g., SCE, customer, etc.).

5. Is SCE aware of any distribution system violations having occurred due to the loss of load (for any reason) in the last five years? If so, please document the number of events that have occurred and for each event provide:
    a. The size of the load reduction,
    b. The type of violation or distribution system impact,
    c. How it was identified,
    d. Whether remediation was necessary, and if so, what remedial action was taken,
    e. If action was taken, the cost and the party responsible for the cost, and
    f. If known, the reason for the load reduction.

6. Has SCE conducted any research and/or analysis on changes in gross load at Non-Exporting sites following installation and operation of the Non-Exporting system? If so please provide a summary of the findings of that research and/or analysis and any underlying documentation.

7. Has SCE done load research and/or impact evaluation to ascertain the net load impact of Non-Exporting projects? If so please provide a summary of the findings of that research and/or analysis and any underlying documentation.

8. How has SCE ascertained the net load impacts of Non-Exporting projects to date?

9. How have these net load impacts been integrated into baseline load conditions for Integration Capacity Analysis (ICA), Grid Needs Assessment (GNA), Distribution Investment Deferral Framework (DIDF), and/or other relevant distribution planning analyses?

10. What, if any, load reductions have been attributed to the aggregate impact of Non-Exporting projects? If any, please describe how they were identified as being attributable to Non-Exporting projects, and identify if these load reductions resulted in the need for any upgrades.

11. How are load reductions from Non-Exporting projects identified and differentiated from load reductions caused by other sources (e.g., energy efficiency, changes in customer demand, etc.)?

12. In SCE's view, if a customer's proposed Non-Exporting project triggers the need for upgrades as a result of load reductions, should the customer be responsible for the cost of those upgrades? If so, what is the basis for requiring the customer to be responsible for those costs?

13. If a customer reduces their load as a result of installing energy efficiency measures, or changes operations in a manner that results in reduced load, and this load reduction triggers the need for upgrades, how does SCE currently recover the cost of those upgrades?

14. If SCE's responses indicate that the cost responsibility should be different for the customers described in questions 12 and 13, please explain the basis for the different treatment.

15. Please provide a spreadsheet that identifies the minimum and peak load for each feeder for each of the last five years, along with the timing of each at whatever granularity is available. If information for a feeder cannot be provided due to customer privacy concerns (i.e., violation of the 15/15 rule), then please indicate that the information is redacted for that reason.

16. Rule 3 provides: "The customer shall give SCE written notice of the extent and nature of any material change in the size, character, or extent of the utilizing equipment or operations for which SCE is supplying electric service before making any such change." Pursuant to this requirement, please identify the number of times that SCE has received a notification from a customer that their load was going to decrease in the last five years.

17. SCE's GNA report provides an accounting for how California Energy Commission load growth forecasts are disaggregated to the feeder level. Please describe the process and analysis that SCE undertakes to forecast localized load reductions, beyond feeder-level programmatic energy efficiency forecasts accounted for in SCE's GNA reporting. For example, in the DFWG Report, Itron noted that SCE makes special adjustments for known locational growth factors (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M229/K731/229731972.PDF); is a similar adjustment made for known load decreases?

18. Please provide normalized and/or per-unit electrification and Distributed Energy Resources load profile assumptions used to calculate peak impacts in SCE's 2021 GNA report.

19. Please describe the business process which SCE uses to identify and plan for distribution upgrades and recovery of costs, that result from large load reductions from a single customer, either due to changes in operations or closing of an account.

DATED: November 29, 2021 SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Sky C. Stanfield

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1438548.5

Southern California Edison
R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Ann Bringas
Job Title: Advisor
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 001:
1. Please provide a sortable spreadsheet including all Non-Exporting projects that have applied to interconnect under Rule 21 in SCE's territory in the last five years, with the following information about each project:
a. Project ID,
b. Project Status (e.g., application accepted, implementation, withdrawn, etc.),
c. Technology Type (e.g. storage, solar, etc.),
d. Customer Rate Class,
e. Use case (e.g., backup power, demand charge reduction, etc.),
f. Type of export control used (e.g., Reverse Power Protection, Minimum Power Protection, Certified Non-Islanding Protection, Relative Generating Facility Rating, Inadvertent Export, or Inadvertent Export Utilizing UL-1741 or UL-1741),
g. Size (total proposed generating capacity in kW, broken out by technology if includes more than one type),
h. Date Application Received,
i. Upgrades required? (If yes, identify type of upgrade),
j. Upgrade required due to load reduction? (yes or no), and
k. If completed, operation date.

Response to Question 001:
SCE understands this question's reference to "Non-Exporting" project to be explicitly non-export projects. There are other non-export facilities paired with exporting facilities (e.g. NEM and R21) that are not represented in the provided data because a queryable search does not exist for these types of paired facilities.

Reference "*IRC Data Request QUESTION 1_Final_Dec 7 2021.xsls*" for information regarding a, b, c, g, h and k.

Please see response for d, e, f, i and j below:

d. Customer Rate Class,

Currently, SCE does not collect this information as part of project application submittal; thus, this data is not readily available.

e. Use case (e.g., backup power, demand charge reduction, etc.),

SCE does not have an automated way to query this information and would need to review individual contracts on a project-by-project basis. Thus, this data is not readily available.

f. Type of export control used (e.g., Reverse Power Protection, Minimum Power Protection, Certified Non-Islanding Protection, Relative Generating Facility Rating, Inadvertent Export, or Inadvertent Export Utilizing UL-1741 or UL- 1741),

SCE does not have an automated way to query this information and every application would need to be reviewed on a project-by-project basis. Thus, this data is not readily available.

i. Upgrades required? (If yes, identify type of upgrade),

SCE does not have an automated way to query this information and every contract would need to be reviewed on a project-by-project basis. Thus, this data is not readily available.

j. Upgrade required due to load reduction? (yes or no), and

SCE does not have an automated way to query this information and every contract would need to be reviewed on a project-by-project basis. Thus, this data is not readily available.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/12/2021

Question 002:
In the February 1, 2019 Response of Southern California Edison Company to Administrative Law Judge's Ruling Directing Responses to Questions on Working Group Two Report, SCE stated: "While SCE believes that the aforementioned safety and reliability issues would result if Non-Exporting projects of all sizes continue to be allowed to bypass screens—i.e., if Screen I is not moved to Rule 21's technical framework overview—SCE does not, at this time, have sufficient information available to answer when, or with what frequency, SCE could begin to experience overvoltage conditions." With respect to this statement, please answer the following questions:
a. Does SCE now have sufficient information available to answer when, or with what frequency, SCE could begin to experience overvoltage or other adverse conditions from the interconnection of Non-Exporting customers? If so, please identify the expected frequency of occurrence (i.e., number of projects a year) and the magnitude of associated upgrade costs you anticipate as a result (in dollars per year). Please also explain the basis for SCE's belief that this will occur and how the company identified the number of events and magnitude of the upgrade costs.
b. If SCE does not have sufficient information to answer when or with what frequency it would begin to experience safety and reliability issues if Non-Exporting projects continue to skip Screen I, what is the basis for SCE's expressed belief that this will result?

Response to Question 002:
a) SCE does not have sufficient information to determine when or with what frequency SCE will begin experiencing overvoltage conditions due to not studying the impacts of Non-Exporting customers.

b) SCE is interconnecting over 400 MW of exporting and non-exporting DER capacity per year, which will lead to load reduction in areas of the grid where these resources are interconnected. Accordingly, to ensure safety and reliability of the grid, SCE needs to study the impact of non-export projects to the power flow within the distribution system. Because non-exporting projects can impact the reliability of the grid similarly to a new exporting generating facility, they should be evaluated comparably.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 003:
Under Rule 21, projects that qualify as Non-Exporting under Screen I are able to skip all subsequent screens, including Screen M. In light of this, if a Non-Exporting project were to trigger the need for an upgrade, how would the triggering conditions be identified today?

Response to Question 003:
The need for an upgrade associated with the operation of a Non-Exporting project would be identified in response to a reliability or safety condition that SCE observed or that was reported to SCE (*e.g.*, a customer reporting an overvoltage condition).

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 004:
At page 54, the Working Group Two Report states that "[i]n the event load changes (i.e., increases or decreases) subsequent to that interconnection, the utility has several approaches to cost allocation for the associated costs. If the change falls under Rules 15 and 16, which cover new line extensions, cost responsibility is determined by the customer's obligations under the line extension contracts. If the change is not covered by Rule 15 and 16, such as for load increases or decreases that emerge in forecasted load, the utility would plan for necessary upgrades, seek approval of those costs from the Commission through a general rate case during the utilities' filing period, and, if approved, collect the costs of the upgrade from all customers." With respect to this language, please provide a sortable spreadsheet which identifies all necessary upgrades and costs associated with load reduction caused by individual Non-Exporting projects in the last five years, including:
a. Project ID (please use the same ID as provided in response to Question 1),
b. Manner in which the upgrade was identified (i.e., through the Rule 21 review process or other means. If other, please describe.),
c. Reason upgrade needed (e.g. protection, voltage, etc.),
d. The type of upgrade (e.g. transformer replacement, etc.),
e. The cost of the upgrade,
f. Whether the upgrade cost was covered by Electric Rules 15 or 16, and if so, which section or subsection,
g. Whether the upgrade cost was instead approved through a general rate case, and
h. Party responsible for cost (e.g., SCE, customer, etc.).

Response to Question 004:
SCE does not have any records indicating that an individual Non-Exporting project caused a distribution upgrade after being interconnected. However, given the volume of Non-Exporting projects expected to be interconnecting to SCE's grid, the likelihood of a Non-Exporting project causing a distribution upgrade to be necessary after being interconnected is expected to increase over time.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 005:
Is SCE aware of any distribution system violations having occurred due to the loss of load (for any reason) in the last five years? If so, please document the number of events that have occurred and for each event provide:
a. The size of the load reduction,
b. The type of violation or distribution system impact,
c. How it was identified,
d. Whether remediation was necessary, and if so, what remedial action was taken,
e. If action was taken, the cost and the party responsible for the cost, and
f. If known, the reason for the load reduction.

Response to Question 005:
SCE understands "loss of load" to mean permanent reduction of load (factory closing, implementation of Energy Efficiency, interconnection of Non-Exporting projects, etc.). SCE is not aware of any distribution system violations having occurred due to loss of load in the last five years.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 006:
Has SCE conducted any research and/or analysis on changes in gross load at Non-Exporting sites following installation and operation of the Non-Exporting system? If so please provide a summary of the findings of that research and/or analysis and any underlying documentation.

Response to Question 006:
SCE has not conducted any analysis on changes in gross load at Non-Exporting sites following the installation and operation of the Non-Exporting system.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 007:
Has SCE done load research and/or impact evaluation to ascertain the net load impact of Non-Exporting projects? If so please provide a summary of the findings of that research and/or analysis and any underlying documentation.

Response to Question 007:
SCE has not conducted load research and/or impact evaluation to ascertain the net load impact of Non-Exporting projects.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 008:
How has SCE ascertained the net load impacts of Non-Exporting projects to date?

Response to Question 008:
To date, any net load impacts of Non-Exporting projects would have been identified as part of SCE's annual Distribution Planning Process.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Johnathon Hughes
Job Title: Engineer
Received Date: 11/29/2021

Response Date: 12/14/2021

Question 009:
How have these net load impacts been integrated into baseline load conditions for Integration Capacity Analysis (ICA), Grid Needs Assessment (GNA), Distribution Investment Deferral Framework (DIDF), and/or other relevant distribution planning analyses?

Response to Question 009:

SCE understands the Non-Exporting projects of this data request to be battery systems that comply with Non-Export/Non-Exporting definition of Rule 21: When the Generating Facility is sized and designed such that the Generator output is used for Host Load only and is designed to prevent the transfer of electrical energy from the Generating Facility to Distribution Provider's Distribution or Transmission System.

Regarding ICA:

- All Non-Exporting projects are modelled within the circuit models to their associated structure and attached to the load they are contracted. However, the Non-Export project is modelled with a zero profile such that the metered load is present within the ICA analysis. Non-Export DERs are assumed to be behind-the-meter, so the meter read for the structure contains the impact of the DER on the load, thus the DER is modeled with a zero profile to avoid double counting.

Regarding GNA, DIDF, and other relevant distribution planning analysis:

- The Distribution Planning Process begins with evaluating historical load profiles and peak load conditions, as detailed in Grid Needs Assessment and Distribution Deferral Opportunity Report Narrative, Section 4.
- The historical profiles include both load and DERs and are examined at the circuit breaker associated with the feeder. The load and DER profiles are aggregates of all associated load and DER customers connected to the circuit. Existing Non-Export projects are captured within the historical profile. SCE uses a globally applied hourly load profile for Energy Storage from the CEC IEPR where telemetry does not exist.
- Historical recorded profiles are assumed to capture all existing load and the impacts of non-export DER projects. This serves as the baseline for which the future forecasted load and DER is built upon to develop the final forecast for which all distribution planning processes and analysis are based.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 010:
What, if any, load reductions have been attributed to the aggregate impact of Non-Exporting projects? If any, please describe how they were identified as being attributable to Non-Exporting projects, and identify if these load reductions resulted in the need for any upgrades.

Response to Question 010:
As indicated in response to Question 8, SCE accounts for the net load impacts of Non-Exporting projects as part of its annual Distribution Planning Process. However, SCE has no records of attributing any load reduction to the Non-Exporting projects nor any records of upgrades being triggered from any potential load reduction of such Non-Exporting projects.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: [Response Date]

Question 011:
How are load reductions from Non-Exporting projects identified and differentiated from load reductions caused by other sources (e.g., energy efficiency, changes in customer demand, etc.)?

Response to Question 011:
Non-Exporting projects are Generating Facilities. Therefore, the identification of load reductions associated with Non-Exporting projects includes the use of generating telemetry data or representative generation profiles.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 012:
In SCE's view, if a customer's proposed Non-Exporting project triggers the need for upgrades as a result of load reductions, should the customer be responsible for the cost of those upgrades? If so, what is the basis for requiring the customer to be responsible for those costs?

Response to Question 012:
In general, for generating facility interconnections, the entity that triggers the need for an upgrade should be responsible for the cost of the upgrade. The basis for this position is the cost-causation principle. For the hypothetical scenario posed in Question 012, if a Non-Exporting (generating facility) project *triggered* the need for an upgrade, it seems consistent with the cost-causation principle that the Non-Exporting project would be responsible for the cost of the upgrade. However, SCE is still reviewing this scenario and will work with the Commission and stakeholders during Phase II of the R.17-07-007 proceeding to address the cost responsibility for upgrades that may be needed to maintain overall grid safety following the interconnection of a Non-Exporting project. In any event, SCE maintains that it is important to study the grid impacts of load reductions from Non-Exporting projects to ensure grid safety and reliability.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 013:
If a customer reduces their load as a result of installing energy efficiency measures, or changes operations in a manner that results in reduced load, and this load reduction triggers the need for upgrades, how does SCE currently recover the cost of those upgrades?

Response to Question 013:
While SCE does not have records of this type of situation occurring, SCE would recover these costs via the Distribution Plant Betterment program if such condition were to occur. The Distribution Plant Betterment Program includes upgrades that arise because of isolated local reasons, including changes in load profiles that drive localized low voltage problems. See SCE's 2021 General Rate Case (A.19-08-013) SCE-02, Vol. 4, Part 2 for additional information on the Plant Betterment Program.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 014:
If SCE's responses indicate that the cost responsibility should be different for the customers described in questions 12 and 13, please explain the basis for the different treatment.

Response to Question 014:
Under Commission jurisdictional tariffs, cost responsibility for retail loads and generating facilities are not the same. SCE will continue to work with the Commission and stakeholders to determine the appropriate cost responsibility for upgrades associated with Non-Export generation projects.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Belinda Vivas
Received Date: 11/29/2021

Response Date: 12/13/2021

Question 015:
Please provide a spreadsheet that identifies the minimum and peak load for each feeder for each of the last five years, along with the timing of each at whatever granularity is available. If information for a feeder cannot be provided due to customer privacy concerns (i.e., violation of the 15/15 rule), then please indicate that the information is redacted for that reason.

Response to Question 015:
Extensive time and effort would be needed to retrieve the requested data beyond the past twelve months as SCE does not have this data readily available. SCE would need IT and programming support to create new data extraction scripts that do not currently exist in order for SCE to provide such requested information. Minimum and maximum load values corresponding to the load profiles published to the public through DRPEP for all circuits over the past twelve months, however, is included in the attached spreadsheet (Min_Max_NetworkID_Profile_value.xlsx).

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Christine Tellez
Job Title: Senior Supervisor
Received Date: 11/29/2021

Response Date: 12/29/2021

Question 016:
Rule 3 provides: “The customer shall give SCE written notice of the extent and nature of any material change in the size, character, or extent of the utilizing equipment or operations for which SCE is supplying electric service before making any such change.” Pursuant to this requirement, please identify the number of times that SCE has received a notification from a customer that their load was going to decrease in the last five years.

Response to Question 016:
Over the last five years, SCE’s Customer Billing Operations group has received a total of 291 Permanent Change in Operating Condition (PCOC) rate change requests from customers permanently reducing their load below the threshold for their current rate. The PCOC is a specific form (Form 14-548) a customer signs to declare that he/she has made a permanent change in operating conditions by installing energy efficient equipment or permanently removing equipment and is therefore eligible for a lower rate or a different rate schedule before the required 12 months is met. Customers, however, can also contact SCE’s Customer Contact Center, Business Customer Division, Planning organization, and/or provide information online at SCE.com to convey changes in their operating conditions. This type of information or communication is generally not tracked in one report.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Phillip Toth
Job Title: Advisor
Received Date: 11/29/2021

Response Date: 12/14/2021

Question 017:
SCE's GNA report provides an accounting for how California Energy Commission load growth forecasts are disaggregated to the feeder level. Please describe the process and analysis that SCE undertakes to forecast localized load reductions, beyond feeder-level programmatic energy efficiency forecasts accounted for in SCE's GNA reporting. For example, in the DFWG Report, Itron noted that SCE makes special adjustments for known locational growth factors (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M229/K731/229731972.PDF); is a similar adjustment made for known load decreases?

Response to Question 017:
The Distribution Forecasting Working Group (DFWG) document mentioned in Question 17 is dated 2018. SCE's current 2021 disaggregation methodology is detailed in the GNA/DDOR narrative R.14-08-013-SCE 2021 GNA and 2021 DDOR Reports (Public), Section 5, pages 13-43.[1]

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Johnathon Hughes
Job Title: Engineer
Received Date: 11/29/2021

Response Date: 12/14/2021

Question 018:
Please provide normalized and/or per-unit electrification and Distributed Energy Resources load profile assumptions used to calculate peak impacts in SCE's 2021 GNA report.

Response to Question 018:
General Assumptions of Historical Profiles:

- Hourly profiles are used such that each hour throughout the year will have a value.
- The nameplate of each DER is used in conjunction with the representative shape to generate the specific DER's profile.
- Assets higher up in the hierarchy (A-Banks and B-Banks) will utilize an aggregate of the DER assets they serve.

Regarding Assumptions for Historical DER Profiles:

- ES:
    - If a DER has telemetry, the telemetry is used.
    - If a DER does not have telemetry, the prior year's CEC IEPR ES profile is used
- PV:
    - PV profiles are generated through a third-party vendor for each unique PV system based on their proprietary modelling process.
- Wind:
    - If a DER has telemetry, the telemetry is used.
    - If the DER does not have telemetry, a zero profile is used.
- Fuel Cell
    - If a DER has telemetry, the telemetry is used.
    - If the DER does not have telemetry, a 100% profile is used.

- Other DER Types
    - If DER has telemetry, the telemetry is used.
    - If the DER does not have telemetry, no profile is used.

Regarding Assumptions for Forecasted DER's:

- Light Duty EV shape:
  - Where EV owners typically charge (home/ away from home)
  - When EV owners start to charge
  - The duration of charging time
  - Residential rate class
- Electric Forklifts:
  - Developed using assumptions from "ICF International and Energy + Environmental Economics, California Transportation Electrification Assessment Phase 3-Part A Commercial and Non-Road Grid Impacts-Final Report, p.18-19 (January 2016)"
- Medium and Heavy Duty EV:
  - Developed using assumptions from "Comparison of Medium- and Heavy-Duty Technologies in California, Appendix B p.49 (December 2019)"
- Electric Bus:
  - Developed using assumptions from "Comparison of Medium- and Heavy-Duty Technologies in California, Appendix B p.49 (December 2019)"
- Electric Transportation Refrigeration Units:
  - Developed using assumptions from "ICF International and Energy + Environmental Economics, California Transportation Electrification Assessment Phase 3-Part A Commercial and Non-Road Grid Impacts-Final Report, p.19-20 (January 2016)"
- Non-Residential Energy Storage:
  - SCE utilized the hourly load profile from the 2019 IEPR
- Residential Energy Storage:
  - SCE utilized the hourly load profile from the 2019 IEPR
- Time of Use
  - SCE utilized the hourly load profile from the 2019 IEPR
- Energy Efficiency
  - SCE utilized the hourly load profile from the 2019 IEPR
- Load Modifying Demand Response
  - SCE developed DER shape based on the SCE's non-residential Critical Peak Pricing (CPP) programs. The CPP is typically dispatched during the summer months of June to September and from 4pm to 9pm a maximum of 12 times per year.
- PV
  - SCE utilized the methodology detailed in 2021 GRC Workpapers, SCE-02 Vol.04 Pt 02 Ch II Bk A, p.96

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 4

To: IREC
Prepared by: Roger Salas
Job Title: Sr. Manager
Received Date: 11/29/2021

Response Date: 12/14/2021

Question 019:
Please describe the business process which SCE uses to identify and plan for distribution upgrades and recovery of costs, that result from large load reductions from a single customer, either due to changes in operations or closing of an account.

Response to Question 019:
SCE interprets this question as asking for a specific business process by which a single customer would notify SCE of large load reductions and SCE would identify and plan for resulting distribution upgrades. SCE does not have a specific business process for this scenario at this time. Generally, SCE identifies distribution upgrades needed to serve retail loads as part of its Distribution System Planning process, which would include identifying load reductions on a system-wide (but not customer-specific) basis.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S FIFTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

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DATED: February 14, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S FIFTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

To:

Ainsley Carreno
Southern California Edison
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Mark McGregor
Southern California Edison
Mark.Mcgregor@sce.com

Pursuant to Article 10 of the California Public Utilities Commission's Rules of Practice and Procedure, the Interstate Renewable Energy Council, Inc. (IREC) hereby serves its Fifth Data Request upon Southern California Edison (SCE) in the above-referenced proceeding.

IREC requests a complete response to this data request as soon as possible, but in no event later than the close of business on March 1, 2022. To the extent any data requests are objected to, IREC requests that any and all objections be specified and the nature of those objections be fully articulated on or before February 22, 2022.

The responses should be sent via e-mail to the following:

Sky C. Stanfield
Shute, Mihaly & Weinberger LLP
Stanfield@smwlaw.com

Stacy Lee
Shute, Mihaly & Weinberger LLP
Slee@smwlaw.com

I. GENERAL INSTRUCTIONS

A. In responding to the following requests, please set forth the request and then state SCE's response.

B. Each request should be deemed continuing in nature. Thus, if SCE acquires additional information regarding any such request, SCE should supplement its response as soon as possible following its receipt of such additional information.

C. In the event that SCE objects to any request on the ground that the information sought is irrelevant or immaterial to any issue in the above-captioned matter, please state the specific basis for such objection, including the basis for any contention that such information is not or does not appear "reasonably calculated to lead to the discovery of admissible evidence . . . ." CPUC Rules of Practice and Procedure, Rule 10.1.

D. In the event that SCE asserts any privilege against the release of any information sought in any request, please specify the privilege asserted and explain the basis of its assertion. In addition, with respect to any document asserted to be privileged, please identify such document.

E. In the event that SCE asserts that any information or document sought is public information or is publicly available, please specify:

1. The title of the document or other source in which the information may be found;

2. The specific page and line number or other precise reference to where the information can be found; and

3. Where the document or other source containing the information can be found.

F. In the event that SCE asserts that any requested information is not available in the form requested, please disclose the following:

1. In what form the information currently exists, including identifying documents;

2. Whether it is possible under any circumstances (and, if so, what circumstances) for SCE to provide the information in the form requested;

3. The procedures or calculation necessary to provide the information in the form requested;

4. The length of time (in hours and days) necessary for SCE to prepare the information in the form requested; and

5. The earliest dates, time period and location that representatives of IREC may inspect SCE's files, records, or documents in which the requested information currently exist.

G. Terms.

1. The terms "documents," "working papers," "studies," "reports," "records," "surveys," "examinations," "research," "reviews," "summaries," "papers," "notes," "memos," and "analysis" are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

2. The terms "data," "figures," "information," "assumptions," "facts," "statistics," "measurements," "findings," and "results" are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

3. "SCE" refers to Southern California Edison.

4. Capitalized terms shall have the same meaning as defined in Rule 21, section C (Definitions).

5. To the extent any other terms are unclear, please assume a reasonable meaning for the term, state the assumed meaning, and respond to the discovery request using the assumed meaning of the term.

H. Identify for each response the person(s) sponsoring the response and corresponding job title(s).

II. DATA REQUESTS

1. In IREC Data Request #4 Question 1, IREC requested a sortable spreadsheet including all Non-Exporting projects that have applied to interconnect under Rule 21 in SCE's territory in the last five years. On December 13, 2021, SCE submitted a data set in its response to Question 1, titled "IRC Data Request QUESTION 1_Final_Dec 7 2021.xlsx," created and modified on Monday, December 13, 2021, 4:57:18 PM. With respect to this document, please answer the following questions:

   a. Does this document include Inadvertent Export projects?

   b. If not, please submit a spreadsheet including all Non-exporting and Inadvertent Export projects that have applied to interconnect under Rule 21 in SCE's territory in the last five years, with the following information about each project listed below. IREC understands that SCE may not have the data for all requested fields.

      i. Project ID,
      ii. Project Status (e.g., application accepted, implementation, withdrawn, etc.),
      iii. Technology Type (e.g. storage, solar, etc.),
      iv. Customer Rate Class,

v. Use case (e.g., backup power, demand charge reduction, etc.),
vi. Type of export control used (e.g., Reverse Power Protection, Minimum Power Protection, Certified Non-Islanding Protection, Relative Generating Facility Rating, Inadvertent Export, or Inadvertent Export Utilizing UL-1741 or UL-1741),
vii. Size (total proposed generating capacity in kW, broken out by technology if includes more than one type),
viii. Date Application Received,
ix. Upgrades required? (If yes, identify type of upgrade),
x. Upgrade required due to load reduction? (yes or no), and
xi. If completed, operation date.

2. The API for SCE's Integration Capacity Analysis (ICA) does not provide access to the criteria threshold violations (thermal, voltage and voltage delta, protection and reduction of reach, operational flexibility, etc.) for each node. Nor does it appear that there is a way to collect that data from the map itself without manually downloading each individual circuit file.

   Please provide the full ICA data, including the criteria violation values for all locations in one comma-separated values (CSV) file, through the API software, or in another accessible manner. IREC is open to discussing the best approach to send and receive a large data set(s).

DATED: February 14, 2022

SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Sky C. Stanfield

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Attorneys for Interstate Renewable Energy Council, Inc.

cc: Kristin Landry, Kristin.Landry@cpuc.ca.gov

1467637.1

Southern California Edison
R.17-07-007 – Rule 21 OIR to Streamline

DATA REQUEST SET I R E C - S C E - 0 0 5

To: IREC
Prepared by: Dane Evenrud
Job Title: Business Analyst II
Received Date: 2/14/2022

Response Date: 3/1/2022

Question 01.a-b:
In IREC Data Request #4 Question 1, IREC requested a sortable spreadsheet including all Non-Exporting projects that have applied to interconnect under Rule 21 in SCE's territory in the last five years. On December 13, 2021, SCE submitted a data set in its response to Question 1, titled "IRC Data Request QUESTION 1_Final_Dec 7 2021.xlsx," created and modified on Monday, December 13, 2021, 4:57:18 PM. With respect to this document, please answer the following questions:

a. Does this document include Inadvertent Export projects?

b. If not, please submit a spreadsheet including all Non-exporting and Inadvertent Export projects that have applied to interconnect under Rule 21 in SCE's territory in the last five years, with the following information about each project listed below. IREC understands that SCE may not have the data for all requested fields.

i. Project ID,
ii. Project Status (e.g., application accepted, implementation, withdrawn, etc.),
iii. Technology Type (e.g. storage, solar, etc.), iv. Customer Rate Class,
v. Use case (e.g., backup power, demand charge reduction, etc.),
vi. Type of export control used (e.g., Reverse Power Protection, Minimum Power Protection, Certified Non-Islanding Protection, Relative Generating Facility Rating, Inadvertent Export, or Inadvertent Export Utilizing UL-1741 or UL-1741),
vii. Size (total proposed generating capacity in kW, broken out by technology if includes more than one type),
viii. Date Application Received, ix. Upgrades required? (If yes, identify type of upgrade),
x. Upgrade required due to load reduction? (yes or no), and
xi. If completed, operation date.

Response to Question 01.a-b:
01.a: Yes
01.b: Please find attached revised spreadsheet which identifies the inadvertent export projects (IR Data Request QUESTION 1_Revised_Feb_28_2022.xlsx)

Southern California Edison
R.17-07-007 – Rule 21 OIR to Streamline

DATA REQUEST SET I R E C - S C E - 0 0 5

To: IREC
Prepared by: Nery Navarro Medrano
Job Title: Engineering Manager
Received Date: 2/14/2022

Response Date: 3/2/2022

Question 02:
The API for SCE's Integration Capacity Analysis (ICA) does not provide access to the criteria threshold violations (thermal, voltage and voltage delta, protection and reduction of reach, operational flexibility, etc.) for each node. Nor does it appear that
there is a way to collect that data from the map itself without manually downloading each individual circuit file. Please provide the full ICA data, including the criteria violation values for all locations in one comma-separated values (CSV) file, through the API software, or in another accessible manner. IREC is open to discussing the best approach to send and receive a large data set(s).

Response to Question 02:
The SCE and IREC teams met on February 24th, 2022, at 4:00 PM (Pacific Time) to discuss Q2. Based on that discussion, SCE is providing this response that provides a proposal on how SCE can provide the requested data, in the most expedited manner, to the IREC team.

During the same Feb. 24th meeting, the IREC team mentioned being able to make a secured cloud storage location available for the SCE team to upload the requested ICA data. SCE would like to request IREC provide such location, with the following considerations:

1. Secured cloud storage location with a minimum storage capacity of 30 GB
2. Access rights to upload data to the location to the following SCE team members:
    a. Sucheta Chakraborty (Sucheta.Chakraborty@sce.com),
    b. Rathish Kumar (Ravindran.Kumar@sce.com), and
    c. Gary C Chin (Gary.Chin@sce.com)

Once SCE obtains access and can verify its ability to upload data to the location IREC provides, the SCE team can start uploading the requested data to that location within one week. SCE estimates the total upload time for all the data can be up to one week, but the estimate is subject to change based on actual network performance and/or system configurations.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S SIXTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

SKY C. STANFIELD
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Slee@smwlaw.com

Attorneys for Interstate Renewable Energy Council, Inc.

DATED: May 19, 2022

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.	Rulemaking 17-07-007 (Filed July 13, 2017)

INTERSTATE RENEWABLE ENERGY COUNCIL, INC.'S SIXTH SET OF DATA REQUESTS TO SOUTHERN CALIFORNIA EDISON

To:

Ainsley Carreno
Southern California Edison
Ainsley.Carreno@sce.com

Mark McGregor
Southern California Edison
Mark.Mcgregor@sce.com

Pursuant to Article 10 of the California Public Utilities Commission's Rules of Practice and Procedure, the Interstate Renewable Energy Council, Inc. (IREC) hereby serves its Sixth Data Request upon Southern California Edison (SCE) in the above-referenced proceeding.

IREC requests a complete response to this data request as soon as possible, but in no event later than the close of business on June 3, 2022. To the extent any data requests are objected to, IREC requests that any and all objections be specified and the nature of those objections be fully articulated on or before May 26, 2022.

The responses should be sent via e-mail to the following:

Sky C. Stanfield
Shute, Mihaly & Weinberger LLP
Stanfield@smwlaw.com

Stacy Lee
Shute, Mihaly & Weinberger LLP
Slee@smwlaw.com

I. GENERAL INSTRUCTIONS

A. In responding to the following requests, please set forth the request and then state SCE's response.

B. Each request should be deemed continuing in nature. Thus, if SCE acquires additional information regarding any such request, SCE should supplement its response as soon as possible following its receipt of such additional information.

C. In the event that SCE objects to any request on the ground that the information sought is irrelevant or immaterial to any issue in the above-captioned matter, please state the specific basis for such objection, including the basis for any contention that such information is not or does not appear "reasonably calculated to lead to the discovery of admissible evidence . . . ." CPUC Rules of Practice and Procedure, Rule 10.1.

D. In the event that SCE asserts any privilege against the release of any information sought in any request, please specify the privilege asserted and explain the basis of its assertion. In addition, with respect to any document asserted to be privileged, please identify such document.

E. In the event that SCE asserts that any information or document sought is public information or is publicly available, please specify:

1. The title of the document or other source in which the information may be found;

2. The specific page and line number or other precise reference to where the information can be found; and

3. Where the document or other source containing the information can be found.

F. In the event that SCE asserts that any requested information is not available in the form requested, please disclose the following:

1. In what form the information currently exists, including identifying documents;

2. Whether it is possible under any circumstances (and, if so, what circumstances) for SCE to provide the information in the form requested;

3. The procedures or calculation necessary to provide the information in the form requested;

4. The length of time (in hours and days) necessary for SCE to prepare the information in the form requested; and

5. The earliest dates, time period and location that representatives of IREC may inspect SCE's files, records, or documents in which the requested information currently exist.

G. Terms.

1. The terms "documents," "working papers," "studies," "reports," "records," "surveys," "examinations," "research," "reviews," "summaries," "papers," "notes," "memos," and "analysis" are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

2. The terms "data," "figures," "information," "assumptions," "facts," "statistics," "measurements," "findings," and "results" are interchangeable and should not be construed to limit the scope of the material sought by this discovery.

3. "SCE" refers to Southern California Edison.

4. Capitalized terms shall have the same meaning as defined in Rule 21, section C (Definitions).

5. To the extent any other terms are unclear, please assume a reasonable meaning for the term, state the assumed meaning, and respond to the discovery request using the assumed meaning of the term.

H. Identify for each response the person(s) sponsoring the response and corresponding job title(s).

II. DATA REQUESTS

In IREC Data Request #5 Question 2, IREC requested full Integration Capacity Analysis (ICA) data, including the criteria violation values for all nodes at all feeder locations. On March 14, 2022, SCE provided IREC ICA results in comma-separated values (CSV) files for 3,877 feeders; the vintage date of the CSV files is therefore assumed to be March 14, 2022. With respect to this data and SCE's Application Programming Interface (API) software, please answer the following questions:

1. IREC noticed that the total number of nodes in the CSV files is greater than the total number of nodes on SCE's API.[1] The "ICA - Circuit Segments, Non-3 Phase" data set available through the API contains data for 624,403 nodes, whereas the CSV files provided to IREC contains 1,443,350 nodes. IREC also noticed that for each feeder, the API data set lists fewer nodes than do the feeders in the CSV files. For example, the "ARBOLES 16KV" circuit in the API contains 242 nodes whereas the "ARBOLES_16kV.csv" CSV contains 781 nodes. Additionally, the node labels (IDs) in the API do not match the node IDs in the CSV files. Please explain why there is a discrepancy in the number of nodes and why there are different node IDs in the API data set and CSV files.

[1] https://drpep-sce2.opendata.arcgis.com/datasets/SCE2::ica-circuit-segments-non-3-phase/

2. IREC combined the CSV files together and extracted the minimum ICA criteria violation values and associated month and hour for each ICA criteria at each node for both minimum and maximum load day conditions. In the CSV files, IREC identified the following observations in the data for each ICA criteria and separated them into two categories in Table 1:

    - **High Capacity**: The percentage of nodes that have a minimum hosting capacity greater than 10,000 kW. ICA criteria where a significant fraction of nodes have a minimum hosting capacity greater than 10,000 kW are highlighted in Table 1.

    - **No Capacity**: The percentage of nodes that have a minimum hosting capacity equal to 0 kW. ICA criteria where a significant fraction of nodes have a minimum hosting capacity equal to 0 kW are highlighted in Table 1.

Table 1: SCE ICA Data Observations, by Percentage of Distribution System Nodes

	High Capacity (Min Capacity > 10,000 kW)		**No Capacity** (Min Capacity = 0 kW)	
ICA Criteria	**Max Load Day**	**Min Load Day**	**Max Load Day**	**Min Load Day**
Generation – Protection	71%	71%	25%	25%
Generation – Operational Flexibility	0%	0%	38%	29%
Generation – Steady State Voltage	18%	19%	17%	11%
Generation – Voltage Variation	30%	31%	1%	1%
Generation – Thermal	15%	15%	2%	2%
Generation – Uniform Operational Flexibility	0%	0%	60%	52%
Generation – Uniform Static Grid	5%	5%	38%	32%
Solar PV – Uniform Operational Flexibility	0%	0%	40%	36%
Solar PV – Uniform Static Grid	2%	2%	31%	28%
Load – Voltage Variation	0%	0%	25%	27%
Load – Thermal	0%	1%	70%	51%
Load – Uniform	0%	1%	77%	58%

3. Based on the results shown in Table 1**Error! Reference source not found.**, IREC requests explanations for the following observations:

    a. For "Generation – Protection" minimum hosting capacity values in Table 1:

        i. Please provide an explanation as to what the Protection technical criteria is evaluating in the ICA model.

        ii. Please confirm that about 71 percent of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain. For reference, PG&E and SDG&E's ICA show greater than 95 percent of nodes having greater than 10,000 kW of capacity for the protection criteria. IREC understands that each utility's distribution system is distinct, but wants to ensure the difference is understood for this criteria.

iii. Please confirm that about 25 percent of nodes having no capacity (0 kW) is consistent with what SCE would expect for its system, and if not, please explain.

iv. Please explain why there are few (about four percent) nodes where the value is between 0 and 10,000 kW.

b. For "Generation – Operation Flex" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 38 percent (at max load day) and 29 percent (at min load day) of nodes having 0 kW capacity is consistent with what SCE would expect for its system, and if not, please explain.

c. For "Generation – Steady State Voltage" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 18 percent (at max load day) and 19 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

ii. Please confirm that approximately 17 percent (at max load day) and 11 percent (at min load day) of nodes having 0 kW capacity is consistent with what SCE would expect for its system, and if not, please explain.

d. For "Generation –Voltage Variation" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 30 percent (at max load day) and 31 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

e. For "Generation –Load" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 15 percent (at max load day) and 15 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

f. For "Load – Voltage Variation" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 25 percent (at max load day) and 27 percent (at min load day) of nodes having 0 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

g. For "Load – Thermal" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 70 percent (at max load day) and 51 percent (at min load day) of nodes having 0 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

DATED: May 19, 2022

SHUTE, MIHALY & WEINBERGER LLP

By: /s/ Sky C. Stanfield

SKY C. STANFIELD
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Attorneys for Interstate Renewable Energy Council, Inc.

cc: Kristin Landry, Kristin.Landry@cpuc.ca.gov

1505498.3

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 6

To: IREC
Prepared by: Belinda Vivas
Job Title: Engineer
Received Date: 5/19/2022

Response Date: 6/3/2022

Question 01:
IREC noticed that the total number of nodes in the CSV files is greater than the total number of nodes on SCE's API.1 The "ICA - Circuit Segments, Non-3 Phase" data set available through the API contains data for 624,403 nodes, whereas the CSV files provided to IREC contains 1,443,350 nodes. IREC also noticed that for each feeder, the API data set lists fewer nodes than do the feeders in the CSV files. For example, the "ARBOLES 16KV" circuit in the API contains 242 nodes whereas the "ARBOLES_16kV.csv" CSV contains 781 nodes. Additionally, the node labels (IDs) in the API do not match the node IDs in the CSV files. Please explain why there is a discrepancy in the number of nodes and why there are different node IDs in the API data set and CSV files.

Response to Question 01:
The API functionality has been updated to show the latest data. The latest analysis shows that API contains a total of 690,472 3-phase nodes. It is expected to see more results in the ICA downloadable files versus the API data because equipment node IDs and segments do not get published in DRPEP; more complete data is therefore being shown in the downloadable files. The ICA and DRPEP teams will analyze if equipment nodes with the corresponding ICA results should be removed from the downloadable files; if equipment related results are removed, the data will match what is being published and shown in the API data set. To SCE's knowledge, the node IDs that do appear in both sets would have the same node labels (IDs). Please note that this is for ICA 3-phase nodes; SCE does not run ICA data for non 3-phase nodes.

Southern California Edison

R.17-07-007 – Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

DATA REQUEST SET I R E C - S C E - 0 0 6

To: IREC
Prepared by: Antonio Nunez
Job Title: Engineer
Received Date: 5/19/2022

Response Date: 6/6/2022

Question 02-03:
IREC combined the CSV files together and extracted the minimum ICA criteria violation values and associated month and hour for each ICA criteria at each node for both minimum and maximum load day conditions. In the CSV files, IREC identified the following observations in the data for each ICA criteria and separated them into two categories in Table 1:

o High Capacity: The percentage of nodes that have a minimum hosting capacity greater than 10,000 kW. ICA criteria where a significant fraction of nodes have a minimum hosting capacity greater than 10,000 kW are highlighted in Table 1.

o No Capacity: The percentage of nodes that have a minimum hosting capacity equal to 0 kW. ICA criteria where a significant fraction of nodes have a minimum hosting capacity equal to 0 kW are highlighted in Table 1.

Based on the results shown in Table 1, IREC requests explanations for the following observations:

a. For "Generation – Protection" minimum hosting capacity values in Table 1:

i. Please provide an explanation as to what the Protection technical criteria is evaluating in the ICA model.

ii. Please confirm that about 71 percent of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain. For reference, PG&E and SDG&E's ICA show greater than 95 percent of nodes having greater than 10,000 kW of capacity for the protection criteria. IREC understands that each utility's distribution system is distinct, but wants to ensure the difference is understood for this criteria.

iii. Please confirm that about 25 percent of nodes having no capacity (0kW) is consistent with what SCE would expect for its system, and if not, please explain.

iv. Please explain why there are few (about four percent) nodes where the value is between 0 and 10,000 kW.

b. For "Generation – Operation Flex" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 38 percent (at max load day) and 29 percent (at min load day) of nodes having 0 kW capacity is consistent with what SCE would expect for its system, and if not, please explain.

c. For "Generation – Steady State Voltage" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 18 percent (at max load day) and 19 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

ii. Please confirm that approximately 17 percent (at max load day) and 11 percent (at min load day) of nodes having 0 kW capacity is consistent with what SCE would expect for its system, and if not, please explain.

d. For "Generation –Voltage Variation" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 30 percent (at max load day) and 31 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

e. For "Generation –Load" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 15 percent (at max load day) and 15 percent (at min load day) of nodes having greater than 10,000 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

f. For "Load – Voltage Variation" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 25 percent (at max load day) and 27 percent (at min load day) of nodes having 0 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

g. For "Load – Thermal" minimum hosting capacity values in Table 1:

i. Please confirm that approximately 70 percent (at max load day) and 51 percent (at min load day) of nodes having 0 kW of capacity is consistent with what SCE would expect for its system, and if not, please explain.

ICA Criteria	**High Capacity** (Min Capacity > 10,000 kW)		**No Capacity** (Min Capacity = 0 kW)	
	Max Load Day	**Min Load Day**	**Max Load Day**	**Min Load Day**
Generation – Protection	71%	71%	25%	25%
Generation – Operational Flexibility	0%	0%	38%	29%
Generation – Steady State Voltage	18%	19%	17%	11%
Generation – Voltage Variation	30%	31%	1%	1%
Generation – Thermal	15%	15%	2%	2%
Generation – Uniform Operational Flexibility	0%	0%	60%	52%
Generation – Uniform Static Grid	5%	5%	38%	32%
Solar PV – Uniform Operational Flexibility	0%	0%	40%	36%
Solar PV – Uniform Static Grid	2%	2%	31%	28%
Load – Voltage Variation	0%	0%	25%	27%
Load – Thermal	0%	1%	70%	51%
Load – Uniform	0%	1%	77%	58%

Response to Question 02-03:
Without extensive rework of the efforts undertaken by IREC, SCE cannot recreate Table 1 from the same data provided to IREC in IREC-SCE-005. However, SCE was able to utilize the latest ICA results to populate Table A below. Assuming that IREC's calculations are correct, SCE's responses to question 3 compare the data shown in Table 1 to the data in Table A in an effort to respond to IREC's questions. SCE is currently undergoing an extensive system-wide refresh that is incorporating major improvements in how input data is transferred into ICA and improving on the data provided. The results below incorporate some level of these system-wide refresh activities, which are scheduled to be completed in August 2022. SCE expects these values to change over time as the system-wide refresh is completed and as further refinements and improvements are made. Consequently, SCE cannot ascertain whether the values presented are "consistent with an SCE expectation level." However, the results in Table A can be used to determine if there is relative consistency with IREC's values. Where the values are not close, an in-depth evaluation will be required to determine reasons for significant differences. SCE has commenced activities to evaluate results and derive levels of expectations for the items noted in Table A.

Table A – Based on Current ICA Results

ICA Criteria	High Capacity (Min Capacity > 10,000 kW)		No Capacity (Min Capacity = 0 kW)	
	Max Load Day	Min Load Day	Max Load Day	Min Load Day
Generation - Protection	85%	85%	13%	13%
Generation - Operational Flexibility	3%	0%	84%	61%
Generation - Steady State Voltage	76%	67%	30%	17%
Generation - Voltage Variation	48%	47%	0%	0%
Generation - Thermal	27%	26%	1%	1%
Generation - Uniform Operational Flexibility	2%	0%	88%	69%
Generation - Uniform Static Grid	18%	17%	38%	26%
Load - Voltage Variation	42%	41%	0%	0%
Load - Thermal	12%	17%	63%	37%
Load - Uniform	9%	12%	74%	47%

3.a.i. The Protection technical criteria used in evaluating ICA is based on the amount of generation that can be installed without creating an adverse impact to end-of-line protection. This is done by defining the phase and ground pickup settings on our protective devices to detect short circuit duties beyond a multiple of 2.3 for phase and 5.0 for ground.

3.a.ii. As shown in Table A, utilization of the latest ICA results indicates that approximately 85% of nodes, as compared to 71% reflected in IREC's table, have capacity greater than 10,000 kW for "Generation – Protection."

3.a.iii. As shown in Table A, utilization of the latest ICA results indicates that approximately 13%

of nodes, as compared to 25% reflected in IREC's Table 1, have 0 kW capacity for "Generation – Protection."

3.a.iv. SCE does not have information readily available to address this question. SCE would have to undertake an extensive analysis to determine why the most limiting hour for each node between 0 and 10,000 kW are within the respective values. Consequently, SCE cannot provide a response to this question at this time.

3.b.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 84% (at max load day) and 61% (at min load day) of nodes, as compared to 38% and 29% reflected in IREC's Table 1, have 0 kW capacity for "Generation – Operational Flexibility."

3.c.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 76% (at max load day) and 67% (at min load day) of nodes, as compared to 18% and 19% reflected in IREC's Table 1, have capacity greater than 10,000 kW for "Generation – Steady State Voltage."

3.c.ii. As shown in Table A, utilization of the latest ICA results indicates that approximately 30% (at max load day) and 17% (at min load day) of nodes, as compared to 17% and 11% reflected in IREC's Table 1, have 0 kW capacity for "Generation – Steady State Voltage."

3.d.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 48% (at max load day) and 47% (at min load day) of nodes, as compared to 30% and 31% reflected in IREC's Table 1, have capacity greater than 10,000 kW for "Generation – Voltage Variation."

3.e.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 27% (at max load day) and 26% (at min load day) of nodes, as compared to 15% and 15% reflected in IREC's Table 1, have capacity greater than 10,000 kW for "Generation – Thermal."

3.f.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 0% (at max load day) and 0% (at min load day) of nodes, as compared to 25% and 27% reflected in IREC's Table 1, have 0 kW capacity for "Load – Voltage Variation."

3.g.i. As shown in Table A, utilization of the latest ICA results indicates that approximately 63% (at max load day) and 37% (at min load day) of nodes, as compared to 70% and 51% reflected in IREC's Table 1, have 0 kW capacity for "Load – Thermal."

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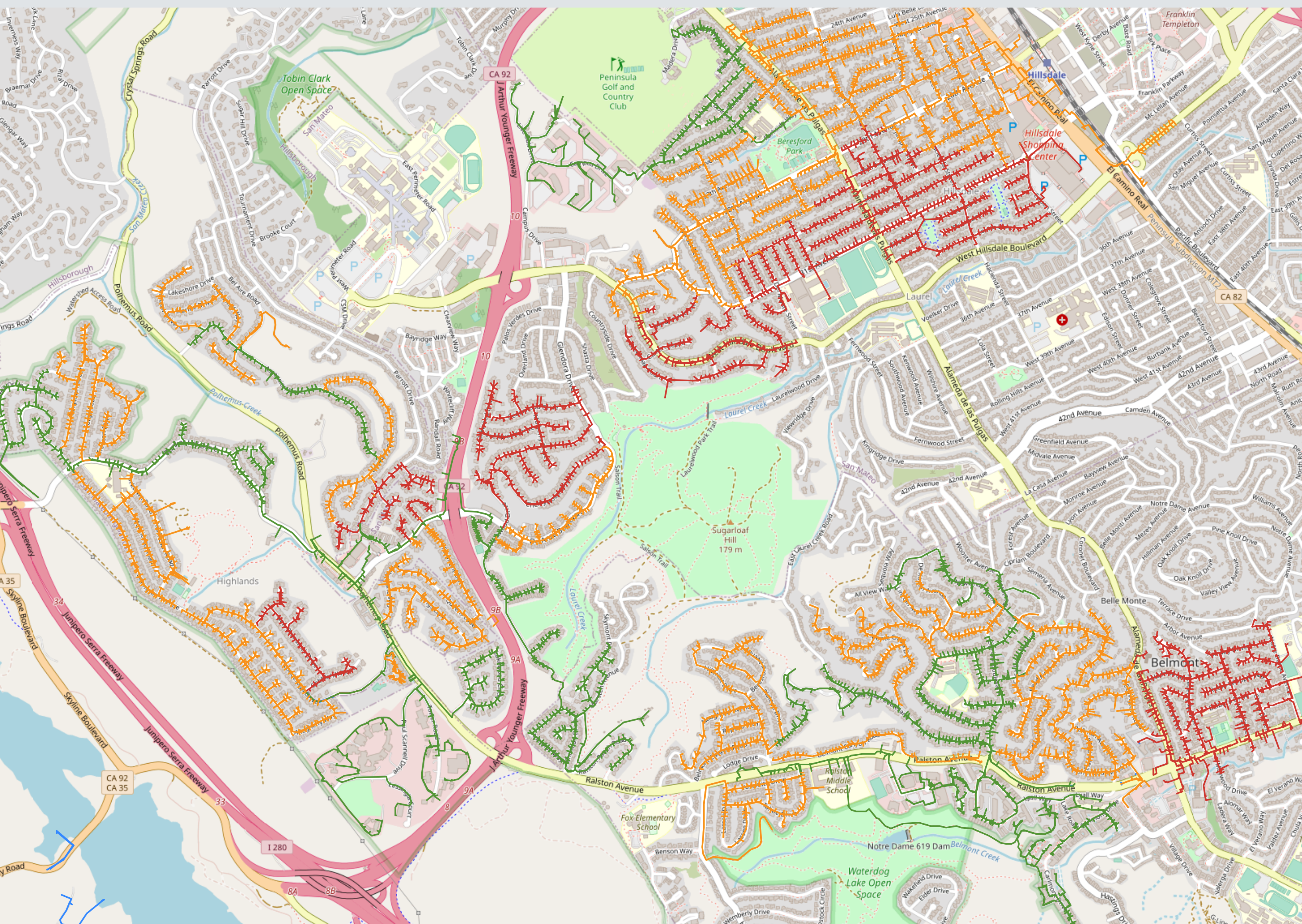
Data Validation for Hosting Capacity Analyses



Data Validation for Hosting Capacity Analyses

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Preface

This report was authored by the National Renewable Energy Laboratory (NREL) and the Interstate Renewable Energy Council, Inc. (IREC).

NREL is a national laboratory of the U.S. Department of Energy (DOE) that specializes in the research and development of renewable energy sources, such as solar, wind, water, and geothermal. NREL is a lead in developing the future of sustainable and integrated energy systems with researchers who harness the power of data and high-performance computing, integrated testing and who focus on integrated solutions, delivering grid modernization and security. NREL has decades of experience providing leadership and novel research in distribution system analyses and planning. The research team that supported this project consisted of subject matter experts on the topic of hosting capacity analysis and has experience exceeding a decade. NREL regularly performs power flow analyses for various purposes, including analyses to further its research on advanced hosting capacity analyses and as a service to distribution utilities.[1]

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. Its vision is a 100% clean energy future that is reliable, resilient, and equitable. IREC develops and advances the regulatory reforms, technical standards, and workforce solutions needed to enable the streamlined integration of clean, distributed energy resources. IREC has been trusted for its independent clean energy expertise for nearly 40 years, since its founding in 1982. IREC's Regulatory Team has been involved in numerous regulatory dockets and research projects associated with the development of distribution system plans and Hosting Capacity Analyses (HCAs).[2] IREC has published two papers and multiple in-depth blog posts about HCA design, which are available at: https://irecusa.org/our-work/hosting-capacity-analysis/.

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[1] For more information, see "Advanced Hosting Capacity Analysis," NREL, https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html.

[2] CA Pub. Util. Comm., Dkt. R.14-08-013, Distribution Resources Plans; CA Pub. Util. Comm., Dkt. R.21-06-017, Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future; NV Pub. Util. Comm., Dkt. 17-08022, Rulemaking to Implement Senate Bill 146 (2017); NY Pub. Service Comm., Dkt. 14-M-0101, Reforming the Energy Vision; NY Pub. Service Comm., Dkt. 16-M-0411, Distributed System Implementation Plans; MN Pub. Util. Comm., Dkt. E999/CI-15- 556, Investigation into Grid Modernization; MN Pub. Util. Comm., Dkt. E002/M-15-962, Xcel Energy Biennial Report on Distribution Grid Modernization; MN Pub. Util. Comm., Dkt. E002/M-17-777, Xcel Energy 2017 Hosting Capacity Study; MN Pub. Util. Comm., Dkt. E002/CI-18-251, Xcel Energy Distribution System Planning; MN Pub. Util. Comm., Dkt. E002/M-18-684, Xcel Energy 2018 Hosting Capacity Study; MN Pub. Util. Comm., Dkt. E002/M-19-685, Xcel Energy 2019 Hosting Capacity Study; MN Pub. Util. Comm., Dkt. E999/CI-20-800, Grid And Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data; MN Pub. Util. Comm., Dkt. E002/M-20-812, Xcel Energy 2020 Hosting Capacity Analysis.

Executive Summary

Solar generation, energy storage, electric vehicles, and other distributed energy resources (DERs) are arriving on the electric distribution grid in fast-growing numbers, but it is not always clear how much incremental DER capacity the distribution system can accommodate. Clarity about grid capacity is of special importance to utilities, developers, and regulators, as well as customers, who are adding more DERs and require accurate, accessible, and trustworthy information.

Such information can be gathered in a hosting capacity analysis (HCA)—a process used by utilities and regulators in multiple states to determine the available capacity for new DERs without requiring expensive and time-consuming studies or grid upgrades. If performed properly, an HCA can streamline and add transparency to DER planning and interconnection processes.

However, some of the first-published HCAs included inaccurate data. For example, a published HCA result showed a feeder with zero capacity, but after an interconnection application was processed, it turned out the feeder actually could accommodate multiple megawatts. This undermined users' confidence in the HCA and raised doubts that the analysis accurately reflected real-world grid conditions. Without confidence in the HCA, users are unlikely to rely on the data and the HCA cannot fulfill its intended purpose. To improve the quality, accuracy, and trust in HCA data and to avoid the challenges found in early rollouts, the National Renewable Energy Laboratory (NREL) and the Interstate Renewable Energy Council (IREC) provide in this report a suite of best practices for HCA data validation.

Implementing this report's HCA data validation practices can increase trust in the HCA, making the results more useful for DER planning and interconnection processes. **The best practices recommended here could be useful for:**

- **Utilities**, to develop or refine their HCA data validation procedures
- **Regulators**, to inform their oversight of utilities' HCA data validation practices
- **Other stakeholders**, to evaluate the effectiveness of utility efforts.

For this work, NREL and IREC interviewed utilities, software vendors, U.S. Department of Energy national laboratories, regulatory commissions, and solar developers to identify common issues in HCA, and reviewed examples of HCA from utilities around the United States to understand current practices. From these findings, this report identifies both procedural and technical best practices for HCA data validation. Our goal is to reduce barriers and provide utilities, regulators, and all stakeholders with a replicable roadmap to help HCA deployments provide accurate, trustworthy, and reliable results from the day they are published.

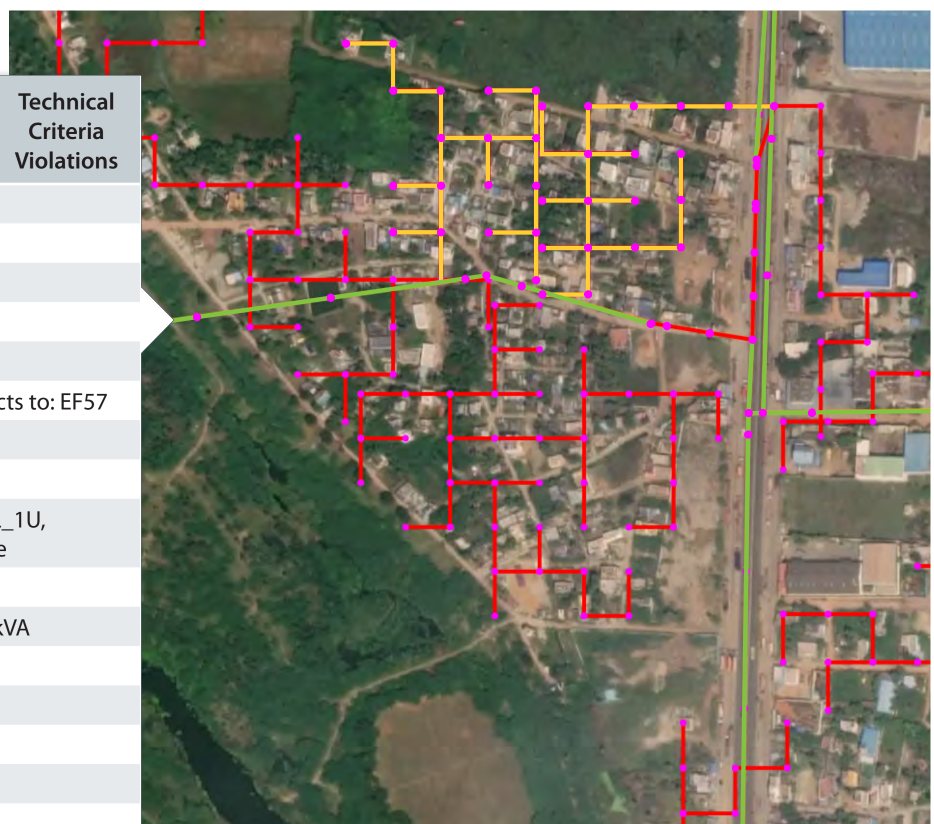
At a high level, HCA best practices include:

- **An appropriately resourced HCA team** that tracks metrics at each step of the process
- A **well-documented, repeatable process** for data validation, using suitable software to ensure digital feeder models reflect real-world grid conditions
- **Transparent and collaborative information sharing** for feedback and identification of errors.

To start, an HCA requires dedicated attention. Successful HCAs are managed by a specific HCA manager to oversee data validation and ensure their HCA team is well resourced. The role of the manager includes establishing and tracking metrics to assess the quality of HCA data in each step, as well as the quality of final results. The manager also works to ensure that each step of the HCA process functions efficiently altogether.

Effective data validation practices include developing, documenting, and following a standardized approach, so that the HCA team can efficiently identify errors and correct the failures in the thousands of nodes that comprise a typical service area. HCA data can have diverse origins involving different utility departments. HCA processes run most efficiently when errors identified by the HCA team are corrected in the source database, even when a different department is responsible for that database.

An HCA also involves building models of distribution feeders to simulate power flow, which is the most common root cause of errors. This report includes tables with examples of validation procedures for each step in the feeder model building process. It is a best practice



Line Section	Substation	Load Profile	Technical Criteria Violations
Section ID: 148104500			
Hosting Capacity: 5,000 kW			
Feeder ID: 23			
Feeder voltage: 12.47			
Number of phases: 3			
Which substation transformer the feeder connects to: EF57			
Feeder type: radial			
Feeder length: 6.213 miles			
Feeder conductor size and impedance: 1000_AL_1U, R1=0.517416 ohm/mile, X1= 0.267376 ohm/mile			
Service transformer rating: 100kVA			
Service transformer daytime minimum load: 35kVA			
Existing generation (weekly refresh rate): 50 kW			
Queued generation (weekly refresh rate): 20 kW			
Total generation (weekly refresh rate): 70 kW			
Currently scheduled upgrades: No			
Federal or state jurisdiction: State			

HCA map example by NREL

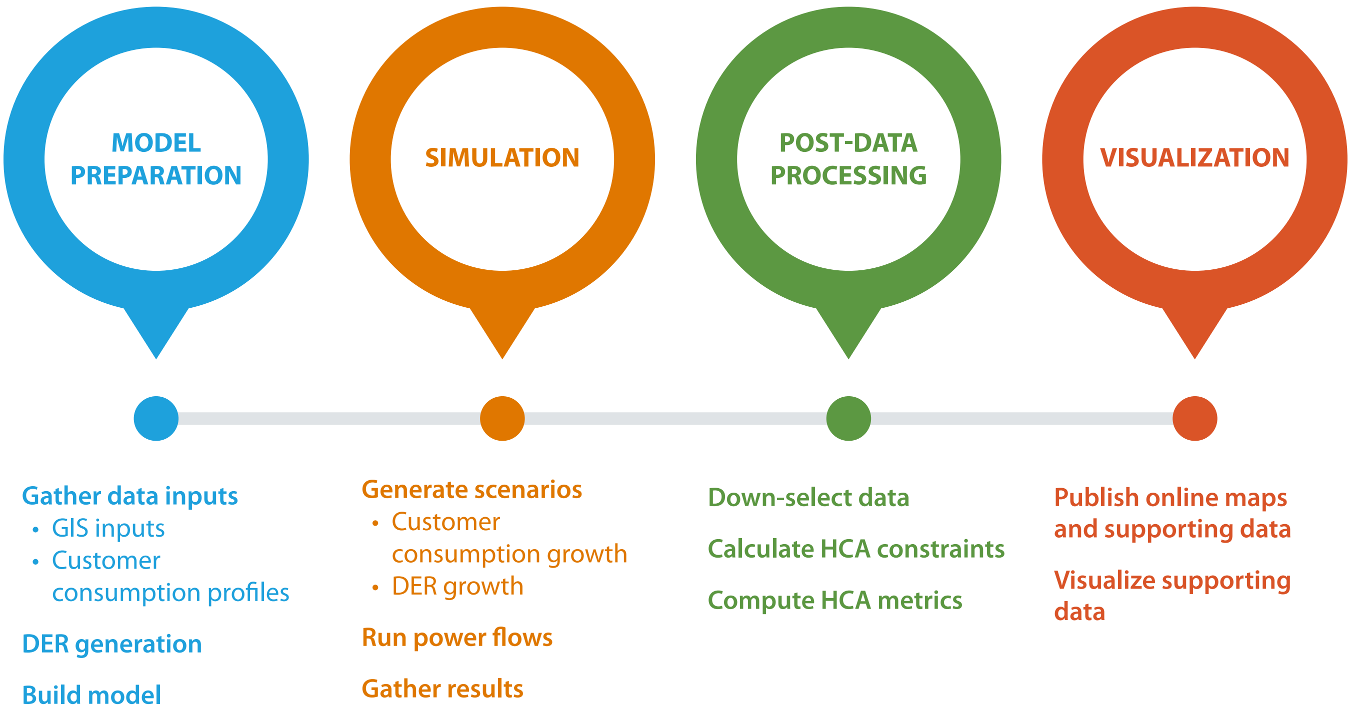


Figure 1. Steps in an HCA. *Illustration by Nicole Leon, NREL*

for utilities to standardize and document the steps in the feeder model building and validation process:

- Feeders that experience similar challenges would benefit from **being batched** so that engineers can easily develop solutions to common problems.
- **Scripting** can be used to automate error correction when building feeder models and to significantly accelerate decision making. Code base management tools are effective in preventing and resolving errors because they allow utilities to track the evolution of code and quickly revert to previous versions if needed.
- Using **actual—not estimated—customer consumption data** improves data accuracy. Existing commercial software, versus tools developed in-house, also provides an advantage in managing consumption profiles since they typically include helpful data validation features.
- Instead of attempting to perform the power flow simulations for an entire year and an entire service area at once, we propose examining a **prioritized set of load hours and a representative sample of feeders** first.

To maximize efficiency and effective public oversight, the HCA process can include measures that prioritize transparency and feedback to help catch errors and elevate confidence in HCA results. Suggested measures include a review process to flag irregularities before publication, as well as a mechanism to allow customers and HCA data users to offer feedback about user experience, identified errors, and usefulness of the HCA data.

Likewise, it is a best practice for regulators to provide transparency into the data validation process. This could be done by reviewing and requiring improvements to data validation plans, tracking the quality of HCA results over time with metrics that describe data quality, and requiring a root cause analysis for recurring problems in the HCA process.

The report identifies best practices for validation procedures, specific rules for identifying data errors, and suggestions for regulatory oversight. Using these processes, utilities and regulators can provide confidence that HCA results accurately reflect grid conditions. With that confidence, trusted HCA data can be used in modernized DER planning and interconnection processes.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. Many NREL and IREC colleagues reviewed and improved this report, including Jess Townsend, Killian McKenna, Peter Gotseff, Aadil Latif, Sky Stanfield, Midhat Mafazy, Radina Valova, and Gwen Brown. We thank the HCA experts listed in section 2.1 that took the time to sit down for an interview with us. As described in section 2.2, this report builds on the recommendations found in Quanta Technology's assessment of California's HCA data validation plans performed by Vic Romero, Stephen Teran, and Andrija Sadikovic. We also thank our DOE colleagues for providing critical review of interim and final work products, including Shay Banton, Michele Boyd, and Susanna Murley. This work was funded by the U.S. Department of Energy's Solar Energy Technologies Office under contract number DE-AC36-08GO28308. All errors and omissions are the sole responsibility of the authors.

List of Acronyms and Abbreviations

AMI	advanced metering infrastructure
CA	California
Comm.	Commission
DER	distributed energy resource
Dkt.	Docket
DOE	U.S. Department of Energy
GAT	grid analysis tool
GIS	geographic information system
HCA	hosting capacity analysis
ICA	integration capacity analysis
IREC	Interstate Renewable Energy Council
kVAr	kilovolt amps reactive
kW	kilowatts
MN	Minnesota
MW	megawatts
NREL	National Renewable Energy Laboratory
NV	Nevada
PG&E	Pacific Gas and Electric Co.
Pub.	Public
QA	quality assurance
QC	quality control
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
Util.	Utilities
VAr	volt amps reactive

Table of Contents

List of Figures

List of Tables

1 Introduction

The usefulness of hosting capacity analysis (HCA) depends on users' confidence that the HCA results accurately reflect grid conditions. Confirming that the data used as inputs to the HCA are ready for use in sophisticated power flow simulations is essential to ensuring HCA results are accurate. This represents one of the most time-intensive parts of developing an HCA.

Failure to adequately validate HCA data before publication will produce an inaccurate representation of the distribution grid that users will not trust. Utility management and regulators can ensure trustworthy HCAs by overseeing the data validation process. This recommendation is rooted in the experience of the first utilities to perform HCA, some of whom published unvalidated results which users did not trust. For example, in January 2019, California utilities published their first systemwide HCA results.[1] Surprisingly, Pacific Gas and Electric's (PG&E's) first HCA showed that approximately 80% of PG&E's feeders had little or no hosting capacity for new solar available, and PG&E, San Diego Gas & Electric (SDG&E), and Southern California Edison's (SCE's) HCA showed 60%–70% of their distribution systems had little to no hosting capacity for new load.[2]

Though it is widely known that PG&E has higher solar deployment, it was highly unlikely that most of the PG&E system had no remaining capacity for new solar projects of any size. Similarly, it would be surprising if 60%–70% of California's grid could not support new distributed loads. These 2019 HCA results did not reflect the reality experienced by customers interconnecting projects and were met with immediate frustration and suspicion that the results were inaccurate.

Stakeholders pointed out to PG&E, SDG&E, and SCE that the results appeared anomalous, and subsequent discussions among stakeholders and regulators led to the conclusion that the results were erroneous.[3] As a result, PG&E implemented a concerted data validation effort that took about 15 months to produce validated results for solar generation.[4] PG&E's solar HCA results have largely been fixed, but problems remain with all three California investor-owned utilities' load HCA results. Over two years after the initial load HCA results were published, those results remain suspect and have yet to be validated. As a result, regulators decided to scrutinize utilities' data validation efforts more closely. The California Public Utilities Commission required each

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[1] In California, HCA is called Integrated Capacity Analysis, but for consistency we use HCA in this document.

[2] CA Pub. Util. Comm. Dkt. R.17-07-007, Response of Pacific Gas and Electric Co. to Data Request 1 of the Interstate Renewable Energy Council, Clean Coalition, and California Solar and Storage Association, at p. 3 (Sept. 28, 2018) (Question 2 re "ICAOF" results); CA Pub. Util. Comm., Dkt. R.14-08-013, Reply Comments of The Interstate Renewable Energy Council, Inc. on Refinements to the Integration Capacity Analysis, Attachment 5: Sept. 9, 2019 Joint Investor-Owned Utility Presentation on Load ICA Methodology and Process, at p. 5 (Sept. 30, 2019) (IREC Reply Comments on ICA Refinements).

[3] See, e.g., IREC Reply Comments on ICA Refinements, at pp. 1–12; CA Pub. Util. Comm., Dkt. R.14-08-013, Administrative Law Judge's Ruling on Joint Parties' Motion for an Order Requiring Refinements to the Integration Capacity Analysis, at pp. 4–6 (Jan. 27, 2021) (CPUC ICA Refinements Order).

[4] PG&E implemented GridUnity's Network Model Management software beginning in Q1 2019 and reported that its maps included verified and published results on May 7, 2020. CA Pub. Util. Comm., Dkt. R.14-08-013, Pacific Gas & Electric's Integration Capacity Analysis Implementation Update, at p. 1 (May 7, 2020).

utility to file a data validation plan, invited stakeholders to comment on the plans, and then hired an independent technical expert to review the plans and suggest improvements.[5]

Concerns about HCA results have also been raised in Minnesota and Massachusetts. In Minnesota, developers reported that Xcel Energy's initial HCA results were unreliable and thus not used. For example, one developer reported that over half "of the locations we screened had more capacity indicated in the screen than the map. We no longer use the map as a result. One location that showed 0 capacity, had 14MW of capacity without upgrades when in final design with Xcel."[6] And in Massachusetts, a developer reported that a utility employee told the developer not to use the HCA because the results were unreliable.

As a result of the flawed HCA rollouts in California and Minnesota, as well as questions raised about the accuracy of first-published HCA maps in other states, the U.S. Department of Energy's Solar Energy Technologies Office agreed to support development of a guide on HCA data validation best practices. This report provides the findings and recommendations from that research. Specifically, it provides utilities with best practices for HCA data validation processes—and recommends that regulators and policymakers oversee the process—so that future HCA deployments provide useful and accurate data from the day they are published. Utilities can use the report to develop or refine their HCA data validation procedures. Regulators can use the report to inform their oversight of utilities' HCA data validation practices. And stakeholders can use it to evaluate the effectiveness of utility efforts.

[5] CPUC ICA Refinements Order, at pp. 4–6 (according to CPUC rules, stakeholders may comment on advice letters).

[6] MN Pub. Util. Comm., Dkt. E002/M-18-684, Fresh Energy's Comments on Xcel's 2018 Hosting Capacity Study, at p. 3 (Feb. 28, 2019).

2 Research Methodology

This project drew on four sources of information to identify HCA data validation procedures: interviews with HCA experts (Section 2.1); a review of relevant documents, including distribution system plans and HCA reports (Section 2.2); NREL's experience conducting power flow analyses and HCAs, and IREC's experience participating in regulatory proceedings that developed and refined HCAs.

Based on the data collected from these sources, NREL and IREC identified issues and errors that commonly occur when performing hosting capacity analyses, and procedures that can address these errors and enhance accuracy of HCA results. Based on the identified issues, errors, and procedures, NREL and IREC in this report identify the use of certain quality assurance (QA), quality control (QC), and regulatory best practices that can help produce HCA results that are accurate and trustworthy.

2.1 Interviews with HCA Experts

We interviewed individuals actively involved in HCA who work for utilities, software vendors, U.S. Department of Energy (DOE) national laboratories, regulatory commissions, and solar developers to identify issues and errors that commonly occur when performing HCAs, and procedures that can address these errors and produce sufficiently accurate HCA results. Before conducting interviews, NREL distributed surveys to each participant to learn about their role in the HCA process and to enable the project team to tailor the interview questions to the participant's experience. We then prepared interview questions based on the survey responses.

The interviews included HCA experts at two distribution utilities, four power flow simulation software vendors, two national laboratories, three regulatory commissions, three solar developers, and one nonprofit. Persons with the following roles and affiliations participated in the interviews, but please note that the report's recommendations are the work of the authors and do not necessarily reflect the views of the interview participants or their employers:

- Synergi Electric Principal Consultant, DNV
- CYME Power System Engineering Manager, Eaton
- Principal Engineer, Electrical Distribution Design, Distributed Engineering Workstation
- Lead Engineer for Distribution Operations and Planning, Electric Power Research Institute
- Principal Engineer, Pacific Gas and Electric Co. (PG&E)
- Manager Distributed Resources Engineering, Arizona Public Service Co.
- Distribution System Engineer, National Renewable Energy Laboratory
- Principal Member of Technical Staff, Sandia National Laboratory
- Staff, Colorado Public Utilities Commission
- Staff, Maryland Public Service Commission
- Staff, Nevada Public Utilities Commission
- Director, Sunrun
- Project Developer, Engie
- Engineer, Borrego Solar Systems
- Regulatory Engineer, IREC

2.2 Review of Distribution System Plans and Hosting Capacity Analysis Reports

We reviewed various documents from California, Minnesota, Nevada, and New York that provide descriptions of and recommendations for HCA data validation procedures.

As described above, the California Public Utilities Commission required utilities that perform HCAs to file a data validation plan and then hired an independent technical expert to review the plans and suggest improvements.[7] We reviewed multiple iterations of the data validation plans of PG&E, SCE, and SDG&E,[8] as well as the independent technical expert's assessment of those data validation plans.[9]

We also reviewed multiple years of Xcel Energy's HCA reports, NV Energy's Distribution System Plans, and New York utilities' HCA workshops, which describe the utilities' HCA data validation practices.[10]

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[7] CPUC ICA Refinements Order, at pp. 4–6.

[8] See, e.g., CA Pub. Util. Comm., San Diego Gas & Electric Co. Advice Letter 3773-E-A, Improved Integrated Capacity Analysis Data Validation Plans, at 4 (Aug. 27, 2021) (SDG&E Data Validation Plan), https://tariff.sdge.com/tm2/pdf/3773-E-A.pdf; CA Pub. Util. Comm., Pacific Gas & Electric Co. Advice Letter 6212-E, Improved Integrated Capacity Analysis Data Validation Plan, Attachment 1: PG&E ICA Data Validation Plan (May 28, 2021) (PG&E ICA Data Validation Plan), https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6212-E.pdf; CA Pub. Util. Comm., Southern California Edison Co., Advice Letter 4508-E, Improved Integration Capacity Analysis Data Validation Plan (May 28, 2021) (SCE Data Validation Plan), https://library.sce.com/content/dam/sce-doclib/public/regulatory/filings/pending/electric/ELECTRIC_4508-E.pdf.

[9] Vic Romero and Stephen Teran, SDG&E Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology (June 24, 2021) (Quanta SDG&E Assessment), https://irecusa.org/wp-content/uploads/2022/02/QTech-SDGE-ICA-Data-Validation-Plan-Assessment-Report-6-28-21.pdf; Stephen Teran and Vic Romero, SCE Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology (June 24, 2021) (Quanta SCE Assessment), https://irecusa.org/wp-content/uploads/2022/02/QTech-SCE-ICA-Data-Validation-Plan-Assessment-Report-6-28-21.pdf; Andrija Sadikovic and Vic Romero, PG&E Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology (June 24, 2021) (Quanta PG&E Assessment), https://irecusa.org/wp-content/uploads/2022/02/QTech-PGE-ICA-Data-Validation-Plan-Assessment-Report_Redacted-6-25-21.pdf.

[10] MN Pub. Util. Comm., Dkt. E-002/M-20-812, Xcel Energy Hosting Capacity Analysis Report (Nov. 2, 2020) (Xcel Energy 2020 HCA Report); MN Pub. Util. Comm., Dkt. E-002/M-18-684, Order Accepting Study and Setting Further Requirements, Xcel HCA, at 4-5 (Aug. 15, 2019); Pub. Util. Comm. of NV, Dkt. 21-06-001, Nevada Power Co. Integrated Resource Plan Vol. 13, Narrative Distributed Resources Plan (June 1, 2021) (NVE 2021 DRP); Joint Utilities of New York, Hosting Capacity, https://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/ (accessed Dec. 14, 2021).

3 Interview Findings

This section presents the interview findings about the common errors encountered in HCAs, and procedures that can address these errors and produce sufficiently accurate HCA results.

3.1 Steps in an HCA

After consulting with HCA experts at the DOE national laboratories, NREL identified four general stages to producing HCAs (Figure 1). Although the specific procedures used in each stage can vary considerably, every successful HCA will include these four stages. This remains true regardless of the use case or methodology selected for the HCA.

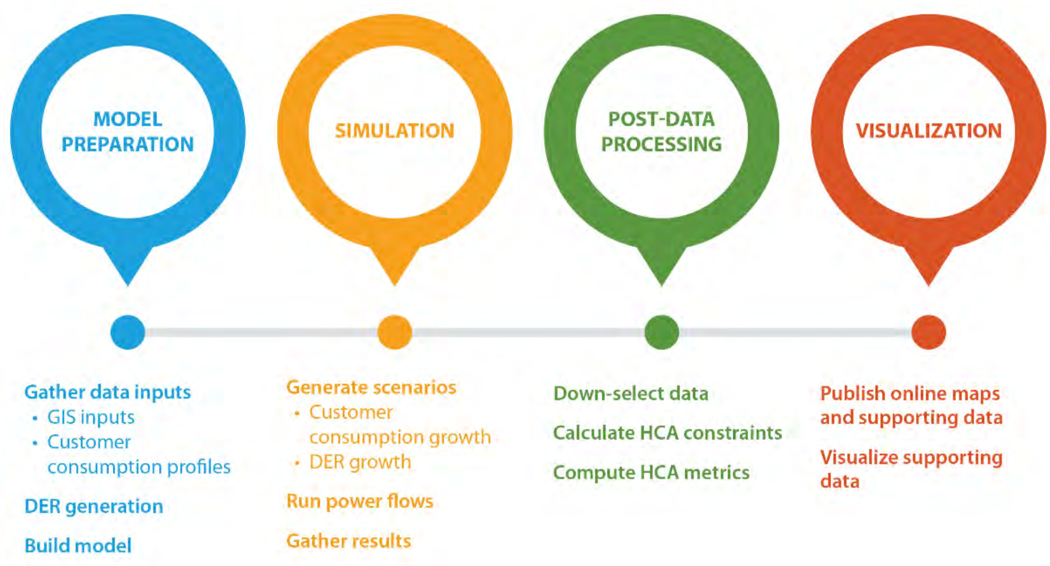

Figure 1. Steps in an HCA. ***Illustration by Nicole Leon, NREL***

The first step is model preparation. A feeder model is a digital representation of a part of the distribution system. The model is designed to match the characteristics of the feeder in the physical world. Ensuring the baseline feeder model accurately reflects the distribution feeder topology, and the load and DER profiles is a critical effort that can take considerable time and resources. Validating a distribution feeder model may require coordination between diverse teams within a utility.

In the second step, engineers and software developers create scenarios that test the ability of the distribution system to accommodate new DERs. The team performing the HCA must manage the status of each feeder as it travels between the various steps. For example, HCA experts we interviewed indicated that the presence of an error or inaccurate results in simulation could indicate the need for revisions to the baseline model, sending the feeder back to the first step.

Utilities often have hundreds of distribution system feeders, and HCAs commonly include hundreds of scenarios for each feeder. The power flow simulation software produces several output files for each scenario. These files are comprehensive and contain voltages, loads, hours, and generation profiles for each node in a feeder. A typical HCA team processes thousands of files.

In the third step, post-data processing often produces errors and inaccurate results that require investigation and correction. This step is critical to assessing accuracy of results at hand. Given the magnitude of data this step needs processes in place to evaluate key metrics. And in the last step, the HCA results are validated, visualizations representing available hosting capacity are produced and then published in various formats, including online maps, tabular files, geographic information system (GIS) files, and application programming interfaces.

3.2 Common Sources of Error

3.2.1 Model Input Errors and Lack of Process to Coordinate Across Utility Crosscutting Teams

The HCA experts we interviewed indicated that the most error-prone stage is feeder model preparation because:

- During the feeder model development and validation process, the HCA team is likely to encounter numerous feeder topology problems whose root cause is an error in the GIS database.
- Fixing GIS errors so that they do not repeat requires established processes, sufficient staffing resources, and cross-team coordination within utilities.
- GIS databases and software were not originally developed to support power flow modeling, and GIS is insufficiently integrated with power flow modeling software.

Power flow simulations assume the feeder model is correct and validated. Without a validated feeder model, a small error at this stage may be amplified and lead to clearly erroneous HCA results. In addition, investing insufficient upfront effort in the data validation process will ultimately cause more work for the HCA team.

3.2.2 Appropriate Use of Software

Power flow modeling software provides the HCA team automated tools that aid data validation efforts by flagging certain errors. Given the magnitude of data involved in an HCA, these tools help streamline and automate the HCA process. Software vendors we interviewed indicated that existing software tools provide basic QA/QC support. Table 1 lists selected capabilities in power flow modeling software that support QA/QC.

Table 1. Selected Capabilities in Power Flow Modeling Software That Support QA/QC

Error Flags	Checks Performed
Missing conductor types	Checks for conductor attributes with null values
Incorrect regulator settings	Checks of regulator controls; verifies whether controllers reach their limit and stop moving up or down
Transformer configuration	Checks for severely overloaded transformers
Inaccurate load data	Checks for anomalies in load values; flags load values far from average

Error Flags	Checks Performed
Mesh or loops in network topology	Checks for meshes and loops; identifies loops and alerts user with warnings
Inaccurate solar irradiance curves	Checks for solar irradiance curves; tools can provide clear sky irradiance based on the latitude and longitude of the solar facility
Zero hosting capacity result	Checks for large areas with zero hosting capacity

3.2.3 HCA Design Choices

In the interviews, several HCA experts we interviewed brought up HCA design choices that often lead to irrelevant HCA results. First, utilities brought up the need to select and clearly define a use case for the HCA. A clearly defined use enables utilities, developers, and regulators to focus their efforts on actions that provide customers the value described in the use case. Second, software vendors brought up the importance of carefully considering and vetting the limiting criteria and thresholds used in the HCA. Selecting improper limiting criteria or thresholds could have a significant impact on HCA results. These design choices are important to consider in the development of an HCA because the wrong choices can lead to irrelevant HCA results, even when accompanied by a data validation process. These design choices, however, are outside the scope of data validation procedures addressed in this report.[11]

3.3 Growing Prominence of HCA

HCA data are receiving additional attention and scrutiny from stakeholders and regulators. Some utilities envisioned an initial use case for their HCA data, but they now see stakeholders and regulators asking to use the data in decision-making processes in more consequential ways. Put another way, stakeholders and regulators may ascribe a higher value to HCA data, and conversely a higher cost to inaccuracies and errors in HCA data. As a result, stakeholders and regulators see significant value in investing in HCA data validation processes.

3.4 Regulatory Activities

We interviewed staff from regulatory commissions in Colorado, Maryland, and Nevada that oversee the publication of HCA data, and two DER developers that are active in markets with published HCAs.

These interviewees indicated a robust stakeholder engagement process produces more useful HCA data for customers. They noted that effective stakeholder engagement processes look to learnings from other states that provide HCA data to customers. As a part of the process, interviewees advised that regulators be open to learning from stakeholders as well as from utilities. Those developing a new HCA tool for the benefit of stakeholders should not presume utilities know the best HCA design. Interviewees indicated they are more likely to trust HCA results when stakeholders are provided the opportunity to make presentations at workshops

[11] For more information about these and other design choices, see Sky Stanfield, Yochi Zakai, Matthew McKerley, *Key Decisions for Hosting Capacity Analyses*, IREC (Sept. 2021), https://irecusa.org/resources/keydecisions-for-hosting-capacity-analyses.

discussing HCA program design, and stakeholders can provide their own proposals for HCA program design.

Regulatory staff are typically unaware of the quality of databases used as inputs into HCA for the utilities that they regulate, according to the regulatory staff we interviewed.

When developers believe HCA results are unreliable, they ask for and prefer to use basic distribution system data instead. Basic distribution system data are normally provided on the same website as the HCA data but are distinct from HCA results.[12] Developers would find HCAs more helpful if they were updated more frequently, used in the interconnection process, and used to identify areas for proactive upgrades. Developers support this recommendation by arguing that utilities are more likely to produce valid and accurate HCAs when utilities use the HCA results in their own interconnection and distribution planning decision-making processes.

[12] Basic distribution system data includes information about feeders and substations, including hourly load profiles, existing and queued generation, voltages, phases, type, length, transformer rating, and known constraints. See, e.g., Key Decisions for Hosting Capacity Analysis, at pp. 11–12.

4 Best Practices

This report provides best practices for utilities and regulators for the design of data validation procedures to support HCAs. In Section 4.1, we discuss the business processes and types of resources necessary to support a robust HCA data validation process. Section 4.2 establishes validation procedures for each step in the feeder model development process. For each step, we include a table with examples of validation procedures. Though the tables are not comprehensive, they provide a starting point for the development of a complete validation process. Section 4.3 highlights ways to ensure results are valid after the utility completes its HCA but before the results are published. In Section 4.4, we discuss accepting feedback from users, and Section 4.5 discusses regulatory oversight of a data validation plan and regular reporting.

4.1 Business Processes

4.1.1 Identify Who Is Responsible for Managing and Improving the HCA and Verification Processes

HCA map generation involves using data generated or maintained across teams within a distribution utility. Successful HCAs involve appointing a specific HCA manager, supported by a team, who will be responsible for managing and improving the HCA processes by providing strategic direction, identifying specific objectives, and establishing a structure for the HCA and data validation activities.[13] The HCA manager, supported by their team, would have ultimate responsibility for data validation, performing the HCA, ensuring the accuracy of HCA results, and improving the efficiency of HCA processes.

HCA and data validation processes are complex and use significant utility resources. An HCA manager helps ensure they are completed in a manner that avoids waste and encourages continuous efficiency improvements. The HCA manager's specific responsibilities include, but are not be limited to: standardizing and documenting the HCA process, validating results, tracking and implementing identified needs for improvement, establishing a long-term strategy to maintain HCA results quality, and managing the processes described in the remainder of this section.

4.1.2 Establish Metrics to Track the Quality of Input Data and HCA Results Over Time

It is a best practice for HCA managers to establish and track metrics.[14] These metrics assess the quality of data used in each step of the HCA process, whether the HCA process is functioning efficiently, and the quality of results. Tracking these metrics over time will help identify trends

[13] Vic Romero and Stephen Teran, SDG&E Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology, at p. 2 (June 24, 2021) (Quanta SDG&E Assessment).
[14] Stephen Teran and Vic Romero, SCE Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology, at p. 3 (June 24, 2021) (Quanta SCE Assessment).

related to data quality and inform root cause analyses.[15] Some examples of metrics that the HCA manager could track include:

- The frequency of errors and issues for each HCA update[16]
- The frequency of each type of failed flag or check (as detailed in Sections 4.2 and 4.3) for each HCA update[17]
- The number of recurring problems in the model building process, and with which source database the problem is associated, if any[18]
- Whether the team completed its processes in the desired time frame and the HCA update was published on time[19]

4.1.3 Fix Identified Problems in the Source Database

Information from a utility's distribution system asset database, GIS database, load database, and generation profile database constitutes the primary inputs used to create the feeder models needed to perform power flow analyses.

Errors in the power flow analyses used to perform the HCA are often due to data quality and integrity problems in the source databases.[20] Efficient HCA processes fix identified errors in the source databases so HCA engineers are not required to fix the same errors each time they use the source database to update a feeder model. Otherwise, engineers often develop a script or another automated solution to fix the error each time they use the source database to update a feeder model. Though scripts remove the need for manual intervention, they are not the best solution because they require the continued use of computing resources and do not correct the problem for other users of the database.

It is a best practice for HCA managers to follow up with the source database owner when a root cause analysis shows the database includes inaccurate data or causes HCA errors.[21] Utilities are often large organizations, and the HCA staff may not interact regularly with the staff that maintain the source databases. We recommend that utilities overcome the challenges associated

[15] Andrija Sadikovic and Vic Romero, PG&E Integration Capacity Analysis Data Validation Plan Assessment, Quanta Technology, at p. 3 (June 24, 2021) (Quanta PG&E Assessment) ("While individual values for the metrics are informative (e.g., there are currently 100 nodes with zero hosting capacity), trends in the metrics can help identify emerging issues in the input data or process (e.g., the count of nodes with zero hosting capacity is not changing over time) or show improvements in quality (e.g., the count of nodes with zero hosting capacity is decreasing on feeders that have recently had limiting factors mitigated). The metrics should also be tracked to support analysis at various levels of system granularity (e.g., system-level, feeder-level, node-level, etc.) and troubleshoot potential data issues.").
[16] Quanta SCE Assessment at p. 14.
[17] Quanta PG&E Assessment at p. 12.
[18] Quanta SCE Assessment at pp. 12–14.
[19] Quanta SCE Assessment at p. 10.
[20] See, e.g., CA Pub. Util. Comm., San Diego Gas & Electric Co. Advice Letter 3773-E-A, Improved Integrated Capacity Analysis Data Validation Plans, at 4 (Aug. 27, 2021) (SDG&E Data Validation Plan), https://tariff.sdge.com/tm2/pdf/3773-E-A.pdf; Quanta SCE Assessment, at pp. 4–5, 12.
[21] Quanta PG&E Assessment at p. 4.

with siloing in large organizations and establish processes that fix identified errors in the source database.

4.1.4 Use Appropriate Employee and Computational Resources

The efficiency and accuracy of HCA processes depends on using appropriate resources, including skilled engineers and computational resources. Resources could be located within the utility or provided by external contractors.

Engineers working on an HCA should have experience with their utility's distribution engineering practices (including planning and operations), circuit models, and design standards.[22] They should also be familiar with the HCA methodology, their utility's implementation of the methodology, and the flow of data from source databases to the feeder model and then to the HCA software. All told, HCA requires skilled engineers with knowledge of the entire HCA process, from input data to the publication of the results.

Using appropriate computational technologies, such as high-performance computers or cloud computing, avoids unnecessary slowdowns due to hardware constraints and accelerates debugging.[23] Performing computationally intensive tasks without the appropriate resources (e.g., on a traditional laptop) will likely slow the entire HCA process, frustrate employees, and prevent HCA results from reaching customers in a timely manner. Providing employees access to the appropriate computing resources can increase the effectiveness and accuracy of the entire HCA process.

While portions of the HCA data validation program can be automated, engineers will always need to correct some problems. Effective HCA managers consider how to strike the right balance between automation and manual work. Although scripting is a powerful tool and commercial software tools are always improving, effective HCA managers monitor for the point at which increased automation provides diminishing efficiency returns.

4.2 Quality Control During the Feeder Model Development Process

The HCA experts we interviewed identified feeder model development as the most error-prone stage of HCA. To address this, recommendations for developing repeatable and streamlined processes to check and correct model input errors at each stage in the HCA process are presented in this section.

4.2.1 Create a Baseline Model and Validate Its Accuracy

A feeder model is a digital representation of a part of the distribution system. A baseline, or base case, digital feeder model is designed to match the characteristics of the feeder in the physical world. Ensuring the baseline feeder model accurately reflects the actual feeder is the first step in

[22] Quanta SCE Assessment at p. 3.

[23] See CA Pub. Util. Comm., Pacific Gas & Electric Co. Advice Letter 6212-E, Improved Integrated Capacity Analysis Data Validation Plan, Attachment 1: PG&E ICA Data Validation Plan, at p. 3 (May 28, 2021) (PG&E ICA Data Validation Plan) ("PG&E's current platform consists of 23 AWS servers with 18 cores (3GHz) processors each, that perform iterative ICA calculations. The platform is supporting ICA calculation of approximately 15% of PG&E circuits, on average, each month."), https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6212-E.pdf.

HCA data validation. Failing to take the time to confirm the accuracy of the initial baseline feeder will create unnecessary work for the HCA team later in the process. Table 2 lists procedures that can be used to validate the baseline model before running hosting capacity scenarios.

Table 2. Baseline Model Validation Procedures

Validation Checks	Validation Procedure
Voltage base	Check whether the feeder head voltage matches the real-world value.
Voltage at nodes	Check for nodal voltage violations at peak load allocation and minimum load allocation.
Loading check	Check for device overloads including transformers and conductor thermal ratings.
Equipment default settings	Check the settings of transformers, capacitors, and regulators in the model to ensure they match the settings of this equipment in the field. If the utility changes settings seasonally, check the model to reflect this seasonal change.
Short circuits	Check value of fault duty (i.e., the maximum current) on each node.
Circuit reactive power	Check the power factor at the feeder head at peak and minimum load.
Circuit losses	Check aggregate active power losses and check power losses as a percentage of load served at the feeder head.
Aggregate active power	Check whether the aggregate active power consumption at the feeder head matches the allocated peak load.

4.2.2 Develop, Document, and Follow a Standardized Approach to Resolving Errors

During the feeder model development and validation process, the HCA team is likely to encounter numerous issues and errors. To efficiently identify errors and correct the failures for the hundreds of feeders in a typical distribution system, the HCA managers develop, document, and follow a standardized approach. Without an organized approach to identifying and resolving problems with feeder models, the process will take longer, and human errors are more likely to occur.[24]

For example, once the baseline feeder models are created, the HCA team will perform the validation checks listed in Table 2. Some feeders will pass all the automated and manual checks, some feeders will produce an automatic warning that indicates review is recommended, and others that fail will require manual review. Effective HCA managers develop a tool that allows the HCA team to track which and how many circuits have passed, produced warnings, or failed at each milestone in the HCA process. Table 3 shows the labels one utility uses to track the progress of feeders through its HCA process. The data produced by this tracking tool can be used to create metrics that allow the HCA manager to monitor the team's progress.

[24] Quanta SCE Assessment at p. 6 ("A best practice to reduce potential human errors when manual intervention is required is using a standardized approach to identify and resolve issues with the distribution circuit models and the [HCA] process.").

Table 3. Statuses Distribution Engineers Can Use to Batch Distribution Circuits for Batch Processing

Status	Description
Completed	The circuit has successfully passed the stage.
Failed	A problem occurred that was serious enough to stop the workflow.
Completed with errors	Indicates an engineer should review the circuit results because the software raised a warning flag.
Stopped	A user chooses to stop a circuit.
In progress	Analysis is actively running.

Source: PG&E Integration Capacity Analysis (ICA) Data Validation Plan, at p. 8.

NREL recommends HCA managers, after identifying feeders with errors, batch feeders with similar challenges to allow engineers to develop efficient, systematic, and repeatable solutions to common problems. If individual engineers begin fixing feeder model errors before the HCA manager knows the number and type of errors found in a large area, other engineers could end up manually fixing the same problem multiple times when an automated solution would have been more appropriate, or different engineers could create automated solutions that are incompatible.

After batching feeders for review, an engineer is typically assigned to review the failed circuits and solve the problem. To streamline the root cause analysis of failures, it is important to document the procedures used to verify four categories of data: topology, equipment, conductor, and customer consumption and generation. The remainder of this section provides detailed recommendations for each category.

4.2.2.1 Topology Verification

A distribution circuit's geographical information is typically stored in a GIS database. This information is used to build the feeder model. When incorrect geographical information is used to build a feeder model, a feeder topology error will result. Errors stemming from incorrect geographical information should be corrected in both the feeder model and the source GIS database to avoid having to fix the same problem every time GIS data are transferred from the GIS database to the feeder model. We recommend adopting the procedures listed in Table 4 to identify errors in feeder topology.

Table 4. Topology Validation Procedures

Validation Check	Validation Procedure
Unintentional islands	Check for the presence of a cluster of nodes with voltages close to zero. This occurrence may indicate the presence of an unintentional island.
Unintentional meshes	Check for meshes in the feeder. Some radial feeders may erroneously mesh due to incorrect switching states. Erroneous meshes will produce incorrect hosting capacity limits.
Incorrect phase loadings	Checking for incorrect phase loadings is not always straightforward. One possible way is to check voltages at nodes during peak load. Incorrect phase loadings are often caused by errors in GIS data, phasing information, or loads.

Validation Check	Validation Procedure
Incorrect feeder switching states	Check if switch states match field data. If a switch is modeled in the incorrect position, the topology of the feeder model is also likely incorrect.
Incorrect phases for voltage correction equipment	Check the phasing of this equipment matches its placement in the real world. Voltage correction equipment such as regulators or capacitors can be single-phase equipment.
Location of existing DERs	Check whether the model places existing DERs on the correct feeder and in the correct phase.[25]

4.2.2.2 Equipment Verification

Distribution system asset databases are used to track equipment, including transformers, capacitors, and regulators. For an HCA, such regulating devices should be considered at their full operation range. The database typically includes the equipment's nameplate rating, configuration settings (e.g., voltage correction settings), and other information. When equipment information in a distribution system asset database is incorrect, the feeder model typically produces incorrect voltages. Table 5 provides a list of equipment validation procedures.

Table 5. Equipment Validation Procedures

Equipment to Check	Typical Issues Associated with Equipment
Substation data for default settings	Substation equipment with default setting (e.g., switches, regulators, reactors, and load tap changing transformers) need to be verified.
Substation regulator or load tap changer	This device sets the voltage of the feeder head and changes the voltage depending on time and the load it is serving. Incorrect voltage step band, time delays, and ratings need to be checked.
Line regulators	Line regulators should be checked for voltage band, time delays, phase, and control modes. With reverse power flows, control modes available in physical device may not have a match in the software.
Capacitors	Capacitors should be checked for kVAr ratings, voltage triggers, time delays, phase, control modes, and seasonal variations.

[25] CA Pub. Util. Comm., Southern California Edison Co., Advice Letter 4508-E, Improved Integration Capacity Analysis Data Validation Plan, at pp. 6–7 (May 28, 2021) (SCE Data Validation Plan) ("One area that has been particularly challenging is the complete and accurate modeling of DER projects in an automated fashion, especially in cases where multiple DER technologies are present at a single location, e.g. solar photovoltaic and battery storage. SCE is in the process of transitioning from multiple existing legacy DER databases to the Grid Interconnection Processing Tool, while making functionality enhancements in parallel to support accurate modeling of DERs. In the interim, SCE performs the following steps on a monthly basis to validate DER project records across multiple source systems to ensure DER projects are modeled accurately: . . . a. Check for DER project location updates: compare project location information from source systems with current customer connectivity to determine if the DER project's circuit has changed due to system reconfiguration
b. Verify equipment size modeled in Grid Connectivity Model (GCM) matches valid project list from source system
c. Verify DER profile information in GAT matches valid project list from source system
d. Verify final circuit modeling data in CYME gateway matches valid project list from source system
7. Compare current month's aggregate DER nameplate size by circuit to previous month's. Identify significant differences, validate and/or correct source data."), https://library.sce.com/content/dam/sce-doclib/public/regulatory/filings/pending/electric/ELECTRIC_4508-E.pdf.

4.2.2.3 Conductor Verification

A feeder model with incorrect conductor types will produce an incorrect reactive power mix, incorrect losses, and incorrect voltage profiles. HCA experts we interviewed indicated that identifying incorrect conductor types can be challenging. For instance, software tools may use different units to describe conductor lengths (e.g., mile, feet, or meters) and line capacitance (e.g., siemens or ohms), which may not align with the units used in the utility databases. Automating the verification of conductor types is not straightforward and thus typically requires a trained distribution engineer. Table 6 outlines some helpful conductor validation procedures.

Table 6. Conductor Validation Procedures

Validation Check	Validation Procedure
Reactive power	Check for the power factor at the feeder head. If a model shows higher or lower VAr or power factor at the feeder head, conductor inductance or capacitance may need validation. This may also mean incorrect power factor allocate for each load as well.
Circuit losses	Check for aggregate power losses of the feeder. Suppose these values are higher or lower than expected and validate line resistances.
Voltage drops at peak load	Check for voltage drop per mile for peak load allocation; higher or lower voltage drops for peak load allocation should indicate higher or lower circuit losses.
Short circuit currents	Check for short circuit currents; higher or lower short circuit currents at nodes may mean incorrect conductor impedances.

4.2.2.4 Customer Consumption (Load) and Generation Profile Verification

Customer consumption profiles consist of two parts: consumption from the grid (load) and behind-the-meter generation profiles.

Using actual consumption data in the HCA produces more accurate results than using estimated consumption data. For example, in its initial HCA rollout, Xcel Energy's HCA team did not have access to daytime minimum load data for almost half the feeders in Minnesota, so they estimated the daytime minimum load by multiplying the feeder's peak load by 20%.[26] After the Minnesota Public Utility Commission ordered Xcel to use actual instead of estimated daytime minimum load data in the HCA,[27] Xcel Energy reported a significant drop in the number of feeders inaccurately showing zero available hosting capacity.[28]

[26] MN Pub. Util. Comm., Dkt. E-002/M-18-684, Order Accepting Study and Setting Further Requirements, Xcel HCA, at pp. 4–5 (Aug. 15, 2019).
[27] MN Pub. Util. Comm., Dkt. E-002/M-18-684, Order Accepting Study and Setting Further Requirements, Xcel HCA, at 14 ("Xcel shall make the tracking and updating of actual feeder daytime minimum load a priority in 2019, and include those values in its 2019 hosting capacity analysis.").
[28] MN Pub. Util. Comm., Dkt. E-002/M-20-812, Xcel Energy Hosting Capacity Analysis Report, Attachment A, at 23 (Nov. 2, 2020) (Xcel Energy 2020 HCA Report) ("The number of feeders with zero maximum hosting capacity decreased by seven from the 2019 analysis, and this was likely the results of using more actual daytime minimum load data for feeders with SCADA in the 2020 analysis.").

Commercial software tools manage consumption data more efficiently and effectively than software developed in-house. Most utilities that perform HCAs use commercial software tools, as they typically include more features, including data validation features, and they are updated regularly.[29]

Consumption data are measured by supervisory control and data acquisition (SCADA) or advanced metering infrastructure (AMI) equipment. SCADA measures the net power flow at a few medium-voltage points, while each customer has their own AMI meter. If a utility has an operating AMI data system, using those AMI data for customer consumption is preferable. To date, utilities have used AMI data primarily to generate customer bills, suggesting it is likely more accurate and precise than SCADA data. Modern AMI equipment can record active power consumption from the grid, and in a separate channel, active power generation from a DER. Modern AMI equipment can also measure voltage and reactive power. AMI measurements are often taken every 15 minutes, and feeders typically have more AMI measurement points than SCADA measurement points. Therefore, there are likely more frequent AMI measurements, and more AMI measurement points, than with a traditional SCADA system. Selected validation procedures for reactive power and load power allocations are provided in Table 7.

Generation profiles should include the maximum potential export for each DER. Generation profiles should include the maximum possible DER output based on solar irradiance information, or a generation schedule for a particular DER. Some utilities maintain their own solar resource database for their service area, but most use open-source databases or third-party vendors.

Table 7. Customer Consumption and Generation Profile Validation Procedures

Validation Check	Validation Procedure
Reactive power allocation	Check whether the load power factor matches the customer class. Each customer class (residential, commercial, and industrial) consumes a different amount of reactive power. Utilities may match reactive power consumption to individual customers or typical power factors for each class. Other times utilities allocate a certain power factor to all loads on a feeder irrespective of customer class. Different assumptions can lead to different errors.[30]

[29] See, e.g., SCE Data Validation Plan, at p. 4 ("SCE has recognized the limited scope of profile validation [using an in-house tool to manage consumption data]. In partnership with SCE's Grid Modernization and Distribution System Planning (DSP) Teams, SCE is in the process of transitioning from [in-house software] to the Grid Analytics Tool (GAT), a commercially supported software tool."); Xcel Energy 2020 HCA Report, Attachment F, at p. 10 ("LoadSEER will allow us to probabilistically simulate DER adoption at a customer level based on system-wide adoption forecasts. This will allow us to study hosting capacity not only based on existing DER on the system, but also based on forecasted levels of DER that may be on the system in the future. Further, LoadSEER will allow us to export forecasted loads at a line section level directly to Synergi – one of the key systems involved in our HCA – which will decrease the amount of time required to allocate load in the Synergi model build process."); SDG&E Data Validation Plan, at p. 5.

[30] See, e.g., Robert Arritt & Roger Dugan, *Comparing load estimation methods for distribution system analysis*, 22nd International Conference and Exhibition on Electricity Distribution (CIRED 2013), pp. 1-4 (June 2013); Li Lin, et al., *Effect of load power factor on voltage stability of distribution substation*, 2012 IEEE Power and Energy Society General Meeting, pp. 1-4 (July 2012).

Validation Check	Validation Procedure
Load allocation	Check for accuracy of active power values (kilowatts or megawatts) either as a proportion of aggregate feeder consumption or as individual values. Raw AMI or SCADA load data must be validated and corrected before used in an HCA.[31] For example, load data from abnormal events (e.g., public safety power shutoffs) should be excluded.[32] Typical checks in customer consumption data include, but are not limited to, nonnumerical results, zeros, and blanks.[33]

4.2.3 Scripting and Versioning the Code Bases

Scripting involves developing a deterministic repeatable process that allows engineers to solve problems and make automations quickly and efficiently. These rule-of-thumb strategies shorten processing times, enhance decision-making, and allow teams to function without constantly stopping to think about their next course of action. Scripting is used to automate error correction in the feeder model building process, and it can significantly accelerate decision making. However, it is important to note that just because a script is developed to efficiently fix a data quality problem in the HCA process does not mean the HCA manager should not attempt to fix the root cause of the data quality problem in the source database.

Because feeders are not uniform, scripting code bases are often modified to reflect the needs of one or two unique feeder configurations. If not properly managed, scripts originally developed to be applied across an entire service area may get complex and customized for various feeder configurations, some of which are unique. Accordingly, using code base management tools ensures the HCA team knows who changed the code most recently, can track the evolution of code, and can revert to previous versions if needed. Using central code bases facilitates better script versioning and reduces misalignment in post-processing. For example, once stakeholders alerted SCE that approximately one-third of the HCA data was missing from its data portal, SCE acknowledged the need to improve its code base management. SCE began using a code base management tool to prevent this problem from reoccurring and now regularly publishes complete results.[34]

4.2.4 Prioritize the Screening Process

After baseline distribution circuit validation, the HCA team prepares scenarios. HCA experts we interviewed indicated that, even after an elaborate baseline feeder validation process, they expect the first set of power flow simulation scenarios to produce numerous errors. This is unsurprising, as HCA is an iterative process, where errors are first identified and resolved, and then eventually a useful result is produced. For this reason, it is important for HCA managers to develop and implement an efficient process for identifying and resolving errors.

Therefore, we propose the scenario simulation process begin by examining a prioritized set of load hours and a representative sample of feeders, rather than attempting to perform the power

[31] See, e.g., Pub. Util. Comm. of NV, Dkt. 21-06-001, Nevada Power Co. Integrated Resource Plan Vol. 13, Narrative Distributed Resources Plan, at pp. 36-37 (June 1, 2021) (NVE 2021 DRP) ("Invariably, not all the loading data for all of the feeders represented normal or accurate telemetry."); SCE Data Validation Plan, at p. 4.
[32] PG&E ICA Data Validation Plan at pp. 15-16; Quanta PG&E Assessment at p. 5.
[33] See, e.g., NVE 2021 DRP, at pp. 36-37; SDG&E Data Validation Plan, at pp. 5–6.
[34] SCE Data Validation Plan, at pp. 11-12.

flow simulations for the entire year and the entire service area at once.[35] The prioritized power flow simulations can help identify issues that are likely to be found throughout the distribution system. We recommend prioritizing critical load hours, including summer peak, summer minimum, winter peak, winter minimum, summer daytime peak, summer daytime minimum, winter daytime peak, and winter daytime minimum. In addition, we recommend selecting a set of representative feeders to prioritize. After errors in the selected hours and feeders are identified, the errors can be fixed throughout the system (in the source database or using automated scripts). This way, the manual intervention required to fix identified problems in later analyses is minimized.

4.3 Validation of HCA Results Before Publication

We recommend HCA managers establish a process to spot errors in HCA results and correct them before publication. As discussed in Section 1, utilities have published HCA results that, upon review by stakeholders, included clearly erroneous data. Therefore, we recommend that after the utility performs the power flow simulation, it establishes a process to flag irregularities that will trigger a review before publication. Table 8 provides a consolidated list of triggers and validation procedures. Most HCA experts we interviewed perform prepublication reviews, but they noted that the feeder model building process is most commonly the root cause of errors identified in the visualization and data publication processes.

Table 8. Consolidated List of Triggers to Validate HCA Results Before Publication

Validation Check	Validation Procedure
No (null) or invalid results	Check for null or invalid results. Implement rule-based screening for null or invalid results, for example:[36] • Are results present for all hours? • Are more than 20 node-hour results blank (null)? • Does the number of null results increase by more than 5% in the current HCA cycle compared to the previous HCA cycle? • Are results numeric? • Are there any null nodes in the final output map?
Zero hosting capacity available	Check for zero hosting capacity values. Implement rule-based screening of zero hosting capacity sections to identify potentially erroneous results. Trigger based on count of feeders or nodes: Most utilities check all HCA results for false negatives, manually reviewing a feeder model if the results show no hosting capacity remains on the entire feeder or when results for 10% or more nodes equal zero for each study criterion.[37]
Duplicate entries	Check for repeating or duplicate entries. Implement rule-based screening for duplicate entries, for example:[38] • Check for duplicate records in final output map.

[35] PG&E ICA Data Validation Plan at pp. 9–10.
[36] SCE Data Validation Plan, at pp. 9–10; Quanta SCE Assessment at pp. 7–8; PG&E ICA Data Validation Plan at pp. 10-11; SDG&E Data Validation Plan, at p. 3.
[37] SCE Data Validation Plan, at p. 9; Quanta SCE Assessment at p. 7; SDG&E Data Validation Plan, at pp. 6–7.
[38] PG&E ICA Data Validation Plan at pp. 10-11; SDG&E Data Validation Plan at p. 7.

Validation Check	Validation Procedure
	• Check for duplicate records in network section table. • Check whether the node has the same or repeating result in more than two hours.
Large discrepancy between previous HCA cycle results and current HCA cycle results	Check for variation between previous HCA cycle results and current HCA cycle results. There are multiple ways to do this, including:[39] • Review the most limiting result for all line segments and bin them into the ranges. Where the binned results for the current cycle differ by more than 5% from the binned results of the previous cycle, flag those results for review. • Review significant changes in the number of times a certain technical criterion is violated.
Random and spot checks	Check a certain number of randomly selected feeders or frequently error encountered circuits. Check for false positives and false negatives. False negatives are results that are not zero but are nonetheless incorrect (e.g., the model produced a result of 100 kW, but the actual result should have been 500 kW).
Additional triggers	Additional miscellaneous checks include:[40] • Check for changes in results because of software upgrades or other changes (e.g., switching to a new version of power flow simulation software or switching to a new load database). • Check for differences in load profile variation and nodal results that could signal an error (e.g., if a load profile varies over time but the hosting capacity at a node does not).

4.4 Acceptance of Feedback from Customers and Users

As explained in Section 1, HCA data users can (1) identify errors that the utility is unaware of and (2) suggest improvements the utility would not conceive of on its own. Therefore, we recommend utilities provide a mechanism to allow customers and HCA data users to provide feedback about the user experience, any errors identified, and the usefulness of the HCA data provided.[41] Utilities can track the feedback they receive and report on any actions taken as a result of the feedback.

4.5 Regulatory Oversight of Data Validation Processes

Utilities can perform data validation independently or regulators can oversee these efforts, for example by requiring a utility to submit a data validation plan and periodic reports including metrics that track the quality of HCA results.[42] We recommend regulators provide transparency into the data validation process by reviewing and requiring improvements to HCA data

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[39] Xcel Energy 2020 HCA Report, Attachment A, at p. 18; Quanta PG&E Assessment at p. 7; SCE Data Validation Plan at p. 10.

[40] Quanta SDG&E Assessment at p. 15; *id.* at p. 7.

[41] Quanta PG&E Assessment at p. 16.

[42] CA Pub. Util. Comm., Dkt. 14-08-013, Administrative Law Judge's Ruling on Joint Parties' Motion for an Order Requiring Refinements to the Integration Capacity Analysis, at pp. 4–6 (Jan. 27, 2021).

validation plans. For example, regulators could require submission of a draft data validation plan, accept feedback from stakeholders on the draft, and then require the submission of an improved data validation plan with periodic reporting on its implementation. HCA experts we interviewed indicate that stakeholder involvement in regulatory processes results in HCAs that provide more useful data to customers. For example, regulators can allow stakeholders to propose that the utility follow certain processes, and regulators can undertake an independent review of HCA processes in other states.

4.5.1 Require Data Validation Plans to Describe the Utility's Data Validation Processes

We recommend regulators require utilities to prepare a data validation plan that describes the utility's data validation process. The plan should identify the HCA manager and describe that person's responsibilities, as outlined in Section 4.1.1. Data validation plans should also describe the employee and computation resources devoted to HCA implementation and data validation. As a part of this description, we propose the utility describe how its plan balances the use of computerized and manual processes, as described in Section 4.1.4.

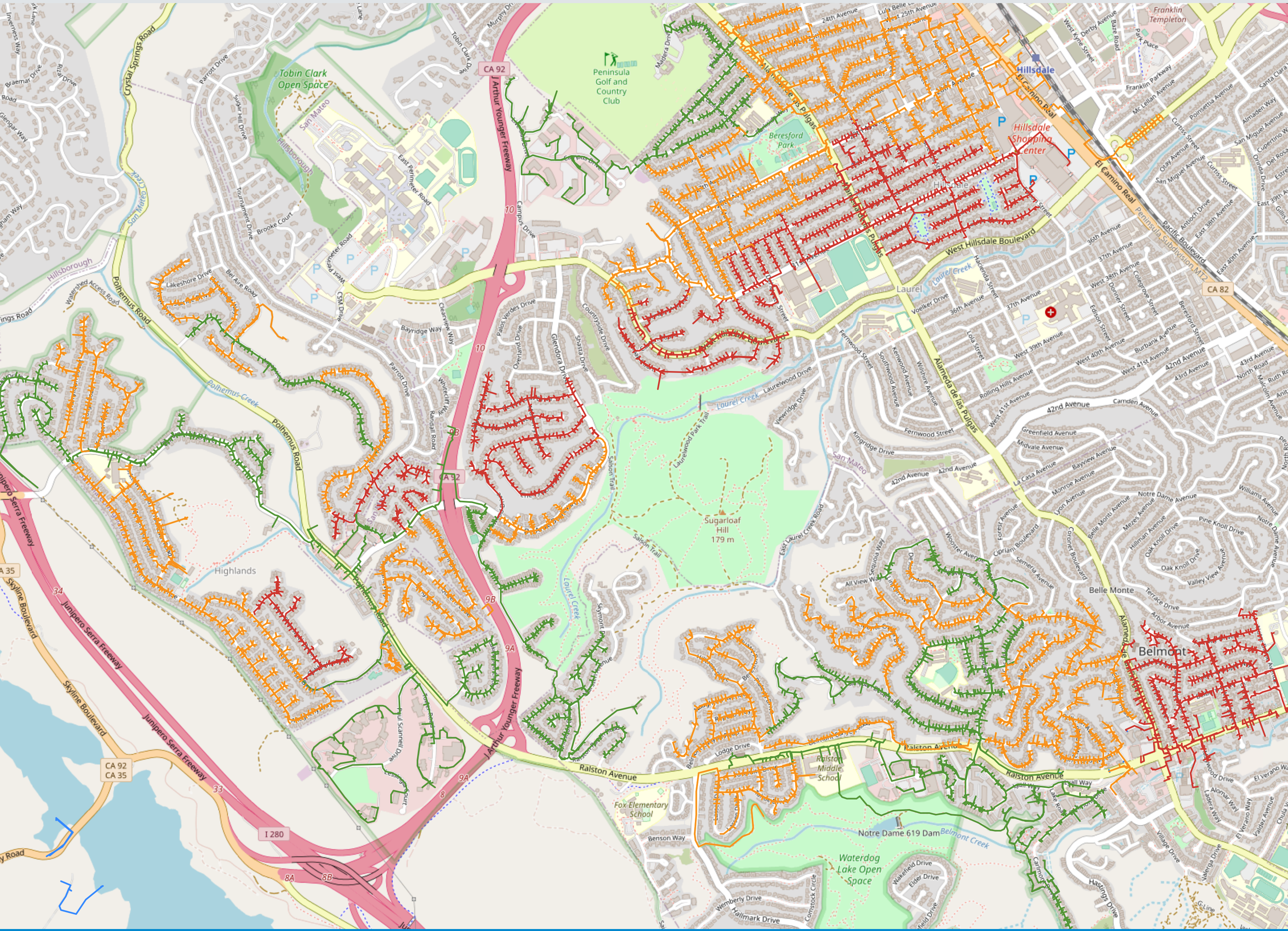
The data validation plans should describe the utility's standardized approach to resolving errors, as outlined in Section 4.2.2, including the use of a prioritized screening process as described in Section 4.2.4. This can include the processes used to verify the baseline model, feeder topology, equipment, conductors, load profiles, and generation profiles. Finally, the plan should describe how the utility validates HCA results before publication, as described in Section 4.3.

4.5.2 Require Periodic Reports to Track the Quality of the HCA Results Over Time

We recommend regulators require periodic reports of metrics that monitor the utility's performance and the accuracy of its HCA results. The reports could include summaries of how many circuits have passed, produced warnings, or failed at each milestone in the HCA process. The reports should include a root cause analysis for recurring problems in the HCA process and action plans with implementation timelines identifying improvements to fix recurring problems. If the action plans do not fix the problems at their source (e.g., a script that automatically corrects errors after importing data from the source database, rather than fixing the errors in the source database), the reports should identify the reasons problems could not be fixed at the source. Finally, we recommend the reports summarize feedback provided by customers concerning the user experience, problems identified, and usefulness of the HCA data (as outlined in Section 4.4) and either action plans for resolving issues identified or explanations why the utility cannot fix the problems or believes doing so is unnecessary.

5 Conclusion

This report is designed to provide utilities, regulators, and stakeholders a set of best practices so that future HCA deployments provide useful, trustworthy, and accurate data from the day they are published, thus avoiding the pain points experienced in early HCA deployments. These best practices include the use of QA, QC, and regulatory processes to help produce accurate and reliable results. We outline how these robust HCA data validation processes can be supported through the establishment of a standard HCA business processes and a well-resourced team. We provide tables with specific examples of validation procedures for each step of the feeder model development and validation process. Finally, we suggest ways to ensure HCA results are valid before they are published and propose that regulators oversee the data validation process by requiring a written plan and regular reporting on data quality metrics.



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