INFORMATION SHEET

PRESIDING: Chairman Finley, Presiding; and Commissioners Brown-Bland, Dockham, Patterson, Gray, Clodfelter, and Mitchell
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: Wednesday, January 30, 2019
TIME: 9:30 a.m. to 12:43 p.m.
DOCKET NO.: E-100, Sub 101; E-2, Sub 1159; E-7, Sub 1156
VOLUME NUMBER: 5
COMPANIES: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
DESCRIPTION: Petition for Approval of Generator Interconnection Standard and Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program

APPEARANCES
Please see attached.

WITNESSES
Please see attached.

EXHIBITS
Please see attached.

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CONFIDENTIAL: Kells (CANNOT RECEIVE DUKE CONFIDENTIAL); Jirak, Breitschwerdt, Kemerait, Ledford, Smith, Dodge, Cummings, Harrod and Townsend

REPORTED BY: Joann Bunze	TRANSCRIPT PAGES: 159
DATE FILED: February 13, 2019	PREFILED PAGES: 86
	TOTAL PAGES: 245

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, January 30, 2019

TIME: 9:30 a.m. - 12:43 p.m.

DOCKET NO.: E-100, Sub 101

E-2, Sub 1159

E-7, Sub 1156

ORIGINAL

BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Charlotte A. Mitchell

IN THE MATTER OF:

Petition for Approval of Generator Interconnection Standard

and

Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program

Volume 5

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC and
DUKE ENERGY PROGRESS, LLC:
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Raleigh, North Carolina 27602

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FOR VIRGINIA ELECTRIC AND POWER COMPANY, d/b/a
DOMINION ENERGY NORTH CAROLINA:
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Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Peter H. Ledford, Esq.

General Counsel

Benjamin Smith, Esq.

Regulatory Counsel

4800 Six Forks Road, Suite 300

Raleigh, North Carolina 27609

FOR INTERSTATE RENEWABLE ENERGY COUNCIL:

Laura Beaton, Esq.

Shute, Mihaly & Weinberger, LLP

396 Hayes Street

San Francisco, California 94102

Lauren Bowen, Esq.

Southern Environmental Law Center

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Chapel Hill, North Carolina 27516

A P P E A R A N C E S Cont'd.:

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Raleigh, North Carolina 27601

FOR NORTH CAROLINA PORK COUNCIL:
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The Law Office of Kurt J. Olson
Post Office Box 10031
Raleigh, North Carolina 27605

FOR CYPRESS CREEK RENEWABLES:
Benjamin Snowden, Esq.
Kilpatrick, Townsend & Stockton, LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

Jennifer Harrod, Esq.
Special Deputy Attorney General
Teresa Townsend, Esq.
Special Deputy Attorney General
Department of Justice
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Tim R. Dodge, Esq.
Layla Cummings, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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EXAMINATIONS

E X H I B I T S

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE 1/28/2019

DOCKET #: E-100 Sub 101

NAME OF ATTORNEY Andrea Kells

TITLE Counsel

FIRM NAME McGuireWoods LLP

ADDRESS 434 Fayetteville St. Ste 2600

CITY Raleigh NC

ZIP 27601

APPEARING FOR: Dominion Energy NC

APPLICANT ✓ **COMPLAINANT** ___ **INTERVENOR** ___

PROTESTANT ___ **RESPONDENT** ___ **DEFENDANT** ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE 1/28

DOCKET #: E100 Sub 1001

NAME OF ATTORNEY Jack Jirak

TITLE Associate General Counsel

FIRM NAME Duke Energy

ADDRESS

CITY

ZIP

APPEARING FOR: Duke Energy

APPLICANT ✓ **COMPLAINANT** ___ **INTERVENOR** ___

PROTESTANT ___ **RESPONDENT** ___ **DEFENDANT** ___

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1-28-11
DOCKET #: E-100 Sub 191
NAME OF ATTORNEY E Brett Breitschwerdt
TITLE Partner
FIRM NAME McGuire Woods
ADDRESS
CITY
ZIP

APPEARING FOR: Duke Energy

APPLICANT X **COMPLAINANT** ____ **INTERVENOR** ____

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Signature: E Brett Breitschwerdt

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1/29/2019
DOCKET #: E-100 sub 101
NAME OF ATTORNEY Karen Kemerait
TITLE attorney for NCCEBA
FIRM NAME
ADDRESS
CITY
ZIP

APPEARING FOR:

APPLICANT ___ **COMPLAINANT** ___ **INTERVENVOR** ✓

PROTESTANT ___ **RESPONDENT** ___ **DEFENDANT** ___

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Signature: Karen Kemerait

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE January 28, 2019
DOCKET #: E-100 Sub 101
NAME OF ATTORNEY Peter Ledford
TITLE General Counsel
FIRM NAME NC Sustainable Energy Association
ADDRESS 4800 Six Forks Road, Suite 300
CITY Raleigh, NC
ZIP 27609

APPEARING FOR: NC Sustainable Energy Association

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** X

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1/23/2019
DOCKET #: E-100 Sub 101
NAME OF ATTORNEY Benjamin Smith
TITLE Regulatory Counsel
FIRM NAME N/A
ADDRESS 4800 Six Forks Road, Ste. 300
CITY Raleigh
ZIP 27609

APPEARING FOR: North Carolina Sustainable Energy Association

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1-28-2019

DOCKET #: E 100 Sub 101

NAME OF ATTORNEY Laura Beaton

TITLE Attorney

FIRM NAME Shute, Mihaly & Weinberger LLP

ADDRESS 396 Hayes St.

CITY San Francisco, CA ~~94102~~

ZIP 94102

APPEARING FOR: Interstate Renewable Energy Council, Inc.

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE E100 Sub 101
DOCKET #: E-100 Sub 101
NAME OF ATTORNEY Lauren Bowen
TITLE Staff Attorney
FIRM NAME Southern Environmental Law Center
ADDRESS 601 W Rosemary St Ste 220
CITY Chapel Hill, NC
ZIP 27516

APPEARING FOR: Interstate Renewable Energy Council

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Email: lbowen@selcnc.org
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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE 1/28/19

DOCKET #: E-100 Sub 101

NAME OF ATTORNEY Kurt Olson

TITLE Counsel

FIRM NAME Law Office of Kurt J. Olson

ADDRESS P.O. Box 10031

CITY Raleigh NC

ZIP 27605

APPEARING FOR: North Carolina Pork Council

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Signature: Kurt J. Olson

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Feb 13 2019

NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1/28/2019
DOCKET #: E-100, Sub 101
NAME OF ATTORNEY Benjamin Snowden
TITLE Counsel
FIRM NAME Kilpatrick Townsend Stockton LLP
ADDRESS 4208 Six Forks Rd., Suite 1400
CITY Raleigh
ZIP 27609

APPEARING FOR: Cypress Creek Renewables

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Email: bsnowden@kilpatricktownsend.com
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Signature: Benj. L.S.

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 01/28/19
DOCKET #: E-100, Sub 101
NAME OF ATTORNEY Tim Dodge & Layla Cummings
TITLE Staff Attorneys
FIRM NAME Public Staff
ADDRESS ~~1503 Bellevue Ave~~ 430 N. Salisbury St.
CITY ~~Durham~~ Raleigh NC
ZIP ~~27~~ 27699-4300

APPEARING FOR: Public Staff

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Email: ~~tim~~ tim.dodge@psncuc.nc.gov
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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE 1/28/19

DOCKET #: E-100, Sub 101

NAME OF ATTORNEY Teresa Townsend Jennifer Harrod

TITLE Special Deputy Attorney General Special Deputy Atty Gen

FIRM NAME DOJ- AGO "

ADDRESS 114 W. Edenton St. "

CITY Raleigh, NC "

ZIP 27603

APPEARING FOR: Using & consuming public & on behalf of State & its citizens in this matter that affects the public interest

APPLICANT ____ **COMPLAINANT** ____ **INTERVENOR** ✓

PROTESTANT ____ **RESPONDENT** ____ **DEFENDANT** ____

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Email: ttownsend@ncdoj.gov + jharrod@ncdoj.gov
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☑ Yes, **I have signed the confidentiality agreement** and would like an electronic copy of the **confidential transcript(s)**

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Signature: Teresa Townsend

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NCCGBA Direct
Exhibit 1

I/-

3.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer and submit a deposit for the estimated costs, or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Utility will return such excess within 20 Business Days of the invoice without interest.

3.4.1 Within ten (10) Business Days following receipt of the deposit for a supplemental review, the Utility will determine if the Generating Facility can be interconnected safely and reliably.

3.4.1.1 In the event that (i) the Interconnection Request is for a modification of an operating generator or a Generating Facility that has completed the Study Process but has not yet been constructed, (ii) limited output hours were assumed in developing the load cases used in the initial study process, and (iii) the Interconnection Request seeks to add energy storage to the Generating Facility, then the Supplemental Review shall evaluate whether the Generating Facility can be operated during hours outside of the limited output hours assumed in developing the load cases used in the initial study process. The Supplemental Review shall identify assumptions around load levels in the System Impact Study, and use that loading to screen other hours based on the Utility's historical load data. The results of this supplemental review shall identify the hours of the day, per season, at which the System Impact Study results are applicable, and the amended Interconnection Agreement shall include the updated Facility specifications and hourly seasonal schedule under which the energy storage system is permitted to operate.

3.4.1.2 Revised Interconnection Agreement

3.4.1.2.1 If the Utility determines that the Generating Facility can be interconnected safely and reliably, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days.

3.4.1.2.2 If the Utility determines that the Generating Facility can be interconnected safely and reliably, and Interconnection Customer facility modifications are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within 15 Business Days after confirmation that the Interconnection Customer has agreed to make the necessary modifications at the Interconnection Customer's cost.

3.4.1.2.3 If the Utility determines that the Generating Facility can be interconnected safely and reliably, and minor modifications to the Utility's System are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days that requires the Interconnection Customer to pay the costs of such System modifications prior to interconnection.

If not, the Interconnection Request will continue to be evaluated under the Section 4 Study Process, provided the Interconnection Customer indicates it wants to proceed and submits the required deposit within 15 Business Days.

Norqual Exhibit 1

Bond No. ______________

I/A

OFFICIAL COPY Nov 20 2018

OFFICIAL COPY Feb 13 2019

FINANCIAL GUARANTEE BOND

Principal: Customer Name
Address
Address
City, State Zip
ATTN: Insert Contact Name and Title

Surety: Surety Name
Address
Address
City, State Zip Code

Obligee: Beneficiary Name
Address
City, State Zip
ATTN: Insert Contact Name and Title

WHEREAS, Principal and Obligee have entered into one or more contracts or agreements for the Description of Activity (collectively, as such contracts or agreements may be amended, modified, supplemented, or extended from time to time, the "Contract") ; and

WHEREAS, pursuant to the Contract, Principal has agreed to provide this Financial Guarantee Bond ("Bond") to meet certain credit requirements of Obligee.

NOW THEREFORE, IT IS AGREED as follows:

1. We, the Principal and the Surety, are jointly and severally held and firmly bound unto Obligee, in the amount of US$________ (Written Amount United States Dollars) ("Bond Amount") for the payment of which we bind ourselves, our heirs, executors, administrators, and successors, and assigns, jointly and severally.

2. Principal and Surety agree this Bond shall remain in full force and effect until the sooner of (a) the date upon which this Bond is replaced with another financial guarantee bond or other form of financial assurance acceptable to Obligee (in its sole discretion); (b) the date upon which this Bond is expressly released in writing by Obligee; or (c) the date upon which Surety has paid Obligee an aggregate amount for claims, whether one or more, equal to the Bond Amount..

3. Surety represents it is duly authorized by the proper authorities to transact the business of indemnity and suretyship in the State of ____________, where it is domiciled and represents it is licensed to be surety and guarantor on bonds and undertakings, which license has not been revoked. Surety represents that it is registered as a Surety with the Department of Treasury and has an A.M. Best Company, Inc. ("A.M. Best") rating of at least A-; VII. Surety further represents that the Bond Amount of this Bond and of all

other bonds issued in connection with the Contract are collectively within Surety's authorized limits for a single risk.

4. Surety represents it has duly executed a Power of Attorney appointing the hereinafter named representative as its duly authorized deputy and the true and lawful Attorney-in-Fact of such Surety as evidenced by the Power of Attorney attached hereto.

5. Nonpayment of premium and costs will not invalidate this Bond nor shall the Obligee be obligated for the payment thereof; Principal shall bear all responsibility for payment of premiums and costs, also to include any replacement bonds required. Surety's obligations to Obligee under this Bond are wholly independent from any agreement or arrangement that may exist now or in the future between Surety and Principal.

6. Surety hereby guarantees and agrees that it is liable for the full and prompt payment, without defense, reduction, or setoff, of all of Principal's obligations and responsibilities set forth in the Contract, as such Contract may be amended from time to time, up to but not exceeding the Bond Amount (the "Obligations"). The Obligations include, without limitation, any amount asserted by Obligee as damages for breach of the Contract, including the amount determined by Obligee to be Principal's remaining transportation fee obligations and responsibilities under the Contract up to but not exceeding the Bond Amount. The Obligations also include any amount initially paid by Principal to Obligee that is subsequently disgorged, clawed back, or returned by Obligee to Principal or its estate as a result of applicable insolvency or bankruptcy laws.

7. Within ten (10) calendar days after delivery by Obligee of written demand to Surety (which may be delivered by hand, registered mail, or overnight courier to Surety's address at INSERT SURETY NAME, ADDRESS, ATTN:) for payment of Obligations hereunder, signed by Obligee's duly authorized official and stating that such Obligations are due and payable under the terms of this Bond, Surety shall pay Obligee the amount demanded in freely transferable funds, without defense, reduction, or offset, up to and including the Bond Amount, in accordance with payment instructions set forth in the demand. There shall be no further condition to Surety's obligation to pay Obligee, and Surety expressly waives any right to assert against Obligee any defense (legal or equitable), counterclaim, setoff, cross-claim, or any other claim that Surety or Principal may now have or at any time hereafter may acquire. It is understood that multiple/partial payments shall be permitted up to the aggregate amount of the Bond Amount. The Bond Amount shall be permanently reduced by the amount of each payment of any Obligation made by Surety to Obligee, except as agreed in writing by Surety. All charges are for the account of the Principal.

8. Surety expressly waives the benefit of any laws requiring Obligee to proceed first against the Principal. Principal and Obligee may make any change to the terms and provisions of the Contract at any time without notice to or consent of Surety and without impairing or releasing the obligations of Surety hereunder. Surety expressly waives protest, notice of acceptance, and demand. The obligations of Surety hereunder are absolute and unconditional, irrespective of the value, validity or enforceability of the obligations of Principal or Obligee under the Contract or any other agreement or instrument referred to therein and, to the fullest extent permitted by applicable law, irrespective of any other circumstance whatsoever that might otherwise constitute a legal or equitable discharge or

defense of a surety in its capacity as such. Surety expressly waives and agrees not to assert any defenses arising out of bankruptcy, insolvency, dissolution or liquidation of Principal, including, without limitation, any defense relating to the automatic stay.

9. Surety shall indemnify Obligee for reasonable attorney's fees Obligee incurs to recover any sums found to be due and owing to Obligee under this Bond, which indemnification obligation shall not be subject to the Bond Amount.

10. Any suit or action under this Bond shall be brought in the courts of the State of North Carolina, the jurisdiction of which Principal and Surety irrevocably submit themselves. This Bond shall be construed according to the laws of the State of North Carolina not including its choice of law rules.

SIGNATURE PAGE FOLLOWS

Bond No. ____________________

IN WITNESS WHEREOF, Principal and Surety have executed this Bond, and it shall be effective on the date set forth below.

The persons whose signatures appear below hereby certify they are authorized to execute this surety bond on behalf of Principal and Surety.

Witnesses our hands to be effective this _____ day of ________________, 20___.

WITNESSES:

By: ______________________________

PRINCIPAL

By: ______________________________
Authorized Signature

Name: ______________________________
Title: ______________________________
Title: ______________________________

SURETY

By: ______________________________

By: ______________________________
Attorney-in-Fact

____
(Name / Title)

I/Vol 4
IA Vol 5

Exhibit SBA-Direct-1

[redacted]

SARA BALDWIN AUCK
774 E 3rd Avenue, Salt Lake City, UT 84103 | (801) 651-7177
sarab@irecusa.org | LinkedIn: @Sara Baldwin Auck

PROFESSIONAL EXPERIENCE

Director, Regulatory Program April 2014 – Present
Interstate Renewable Energy Council, Inc.
Develop and implement national regulatory strategy on interconnection, grid modernization, energy storage, smart inverters, multifamily solar access policies, and community solar; track and oversee intervention in 20 concurrent state proceedings in 15 states, coordinating with local and state partners and developing policy positions; write grants, develop program budgets, and report on successes to private and public funders; develop communication products, including reports, blogs, articles, and podcasts to expand influence and impact among target audiences; respond to media inquiries, conduct interviews, and contribute to social media discussions; create and deploy new regulatory tools and resources to educate state and national audiences about policy best practices; develop sessions and present at national educational conferences and events; supported National Technical Team for U.S. Department of Energy Solar Market Pathways effort; serve on Grid Lab Advisory Board; identify and execute strategic partnerships with national network of industry, educational, research and advocacy organizations.

Senior Policy & Regulatory Associate May 2004 – March 2014
Utah Clean Energy
Directed and implemented strategic policy and regulatory efforts to advance clean energy successes in Utah and the West; managed award-winning U.S. Department of Energy funded projects, including the Wasatch Solar Challenge and Solar Salt Lake Project; coordinated with U.S. national labs and other experts on technical assistance efforts on policy and technical issues; interfaced with regulators, policymakers, and local governments on clean energy projects; led adoption of favorable clean energy legislation and regulatory reforms.

Adjunct Instructor, Renewable Technologies Course Spring 2011
Salt Lake Community College
Developed core curriculum around renewable energy technologies; coordinated with industry representatives on class presentations, tours, and industry briefings; assessed student performance.

BOARDS, TASK FORCE AND SERVICE

- Grid Lab Advisory Board (present)
- Distributed Generation Interconnection Collaborative Advisory Committee (present)
- Solar Power International Education Committee (2017)
- Renewable Energy Advocates Convening Advisory Committee (2017)
- Chair & Vice-Chair, Salt Lake Climbers Association (2012 - 14)
- Utah Technology Council Public Policy Committee (2010 - 14)
- Utah Governor's 10-Year Energy Initiative, Energy & Environment Subcommittee (2010 - 11)
- Utah Solar Energy Association Advisory Board (2007 - 12)
- Utah's Renewable Energy Zone Task Force (Phase I and Phase II) (2008 - 09)
- Original co-founder and Advisory Board Member, Utah Solar Industries Association (2008)
- Utah's Renewable Energy Initiative Working Group (2007)
- Utah Governor's Blue Ribbon Advisory Council on Climate Change Stakeholder Group (2006 - 07)

[redacted]

AWARDS, RECOGNITION & RELATED EFFORTS

- Grid Geeks Podcast Host (present)
- 2017 Innovator & Influencer, Solar Power World (2017)
- Finalist for Governor's Excellence in Energy Award for Salt Lake Community Solar (2013)
- Utah Business Magazine Sustainable Business Award, Salt Lake Community Solar (2012)
- Community Foundation of Utah 2012 Enlighted 50 (2012)
- U.S. Department of Energy Solar America Cities "Barrier Buster Award" (2011)
- U.S. Department of Energy Solar America Cities "Mountain Mover Award" (2010)
- NREL, Wind Powering America "Outstanding Young Wind Advocate" (2008)

PRESENTATIONS (SAMPLE)

- National Association of State Utility Consumer Advocates Mid-Year Meeting (2018)
- National Governors' Association Policy Summit (2018)
- National Governors' Association Experts Roundatable (2018)
- SEIA/ESA Breakfast at NARUC Annual Meeting (2018)
- NARUC Energy Resources and Environment Committee Meeting (2018)
- GTM U.S. Energy Storage Summit (December 2017)
- National Governors' Association Ahead of the Curve Energy Summit (October 2017)
- US Department of Energy 7-Day Race to Solar Workshop on Interconnection at Solar Power International (September 2017)
- Utah Legislature Public Utilities, Technology, & Energy Interim Committee (September 2017)
- Pacific Northwest Energy Storage and Demand Response Summit (September 2017)
- Solar Power International, SEIA Grid Modernization Workshop (September 2017)
- Energy Storage North America (August 2017)
- Intersolar North America (July 2017)
- Maryland Public Service Commission, PC 44 Energy Storage Workgroup (May/June, 2017)
- US Department of Energy Solar Market Pathways Leadership Academy (May 2017)
- Energy Storage Association Policy Committee Webinar (May 2017)
- EUCI New York REV Summit (April 2017)
- Maryland Public Service Commission, PC 44 Interconnection Workgroup (March 2017)
- NARUC Winter Committee Meeting (February 2017)
- Energy Storage Association NARUC Winter Meeting Breakfast (February 2017)
- Energy Storage Association Policy Forum (February 2017)
- Legislative Energy Horizon Institute (October 2016)
- National Association of State Energy Offices and National Conference of State Legislatures Joint Meeting (July 2015)

EDUCATION AND TRAINING

Honors B.S., Environmental Studies and B.A. Spanish, Phi Beta Kappa 2000-2005
University of Utah
Honors Program Graduate | Academic Achievement Award Recipient | Environmental Studies Student Advisory Committee | Co-Director, Environmental Action Team, Lowell Bennion Community Service Center

International Student Exchange Spain 2003
Universidade de Vigo
Certificado en Curso de Español Para Extranjeros; *Superi*

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Exhibit SBA-Direct-2

NORTH CAROLINA

INTERCONNECTION PROCEDURES, FORMS, AND AGREEMENTS

For State-Jurisdictional Generator Interconnections

IREC Proposed
Revisions 11/17/2018
~~Effective 5/15/2015~~

Docket No. E-100, Sub 101

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Section 1. General Requirements

1.1 Applicability

1.1.1 This Standard contains the requirements, in addition to applicable tariffs and service regulations, for the interconnection and parallel operation of Generating Facilities with Utility Systems in North Carolina. These procedures apply to Generating Facilities that are interconnecting to Utility Systems in North Carolina where the Interconnection Customer is not selling the output of its Generating Facility to an entity other than the Utility to which it is interconnecting.

Interconnection Requests for new Generating Facilities shall be submitted to the Utility for approval at the final design stage and prior to the beginning of construction.

The submission of a written request for a Section 1.2 Pre-Request Response and/or Section 1.3 Pre-Application Report is encouraged to identify potential interconnection issues unforeseen by the Interconnection Customer.

Revised Interconnection Requests for equipment or design changes should be submitted pursuant to Section 1.5.

Notification by the Interconnection Customer to the Utility of change of ownership or change in control should be submitted pursuant to Section 6.11.

1.1.1.1 A request to interconnect a certified inverter-based Generating Facility no larger than 20 kW shall be evaluated under the Section 2, 20 kW Inverter Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.2 A request to interconnect a certified Generating Facility no larger than the capacity specified in Section 3.1 shall be evaluated under the Section 3 Fast Track Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.3 A request to interconnect a Generating Facility larger than the capacity stated in Section 3.1, or a Generating Facility that does not qualify for or pass the Fast Track Process or qualify for the 20 kW Inverter Process, shall be evaluated under the Section 4 Study Process. Interconnection Customers that qualify for Section 2 or Section 3 may also choose to proceed directly to Section 4 if they believe Section 4 review is likely to be necessary.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 [A1]The 2015 revisions to the Commission's interconnection standard shall not apply to Generating Facilities already interconnected as of the effective date of the 2015 revisions to this Standard, unless the Interconnection Customer proposes a Material Modification, transfers ownership of the Generating Facility, or application of the 2015 revisions to the Commission's interconnection standard are agreed to in writing by the Utility and the Interconnection Customer. This Standard shall apply if the Interconnection Customer has not actually interconnected the Generating Facility as of the effective date of the 2015 revisions.

Any Interconnection Customer that has not executed an interconnection agreement with the Utility prior to the effective date of the 2015 revisions to this Standard shall have 30 Calendar Days following the later of the effective date of the Standards or the posted date of notice in writing from the Utility to demonstrate site control pursuant to Section 1.6, and to post the deposit outlined in Section 1.4.

Any Interconnection Customer that has executed an interconnection agreement with the Utility prior to the effective date of this Standard but the Utility has not actually interconnected the Generating Facility, shall have 60 Calendar Days to submit Upgrade and Interconnection Facility payments (or Financial Security acceptable to the Utility for Interconnection Facilities only) required pursuant to Section 5.2. Any amounts previously paid by the Interconnection Customer at the time deposit or payment is due under this Section shall be credited towards the deposit amount or other payment required under this Section.

1.1.4 Prior to submitting its Interconnection Request, the Interconnection Customer may ask the Utility's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Utility shall respond within 10 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to Interconnection Agreement are to the North Carolina Interconnection Agreement. (See Attachment 9.)

1.2 Pre-Request Response

1.2.1 The Utility shall designate an employee or office from which information on the application process can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Utility's Internet web site.

1.2.2 The Interconnection Customer may request a Pre-Request Response by providing the Utility details of a potential project in writing, including site address, grid coordinates, project size and proposed Point of Interconnection.

Electric system information provided to the Interconnection Customer should include number of phases and voltage of closest circuit, distance to existing source, distance to substation, and other information and/or materials useful to an understanding of an interconnection at a particular point on the Utility's System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Utility shall comply with reasonable requests for such information in a timely manner, not to exceed ten (10) Business Days. The Pre-Request Response produced by the Utility is non-binding and does not confer any rights. The Interconnection Customer must still meet the Section 1.4 requirements to apply to interconnect to the Utility's system and to obtain a Queue Number. Any one developer shall have no more than five (5) requests for Pre-Request Responses in the Pre-Request Response queue at one time.

1.3 Pre-Application Report

1.3.1 In addition to, or instead of, requesting an informal Pre-Request Response, an Interconnection Customer may submit a formal written Pre-Application Report request form (see Attachment 3) along with a non-refundable fee of $300 for a Pre-Application Report on a proposed project at a specific site. The Utility shall provide the Pre-Application data described in Section 1.3.2 to the Interconnection Customer within ten (10) Business Days of receipt of the completed request form and payment of the $300 fee. The Pre-Application Report produced by the Utility is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Utility's system and to obtain a Queue Number. The written Pre-Application Report request form shall include the information in Sections 1.3.1.1 through 1.3.1.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection. Any one developer shall have no more than five (5) requests for Pre-Application Reports in the Pre-Application Report queue at one time.

1.3.1.1 Project contact information, including name, address, phone number, and email address.

1.3.1.2 Project location (street address, location map with nearby cross streets and town, etc.).

1.3.1.3 Meter number, pole number, location map or other equivalent information identifying proposed Point of Interconnection, if available.

1.3.1.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.3.1.5 Size (alternating current kW).

1.3.1.6 Single or three phase generator configuration.

1.3.1.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.3.1.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.3.2. Using the information provided by the Interconnection Customer in the Pre-Application Report request form in Section 1.3.1, the Utility shall identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Utility does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple Points of Interconnection is requested. Subject to Section 1.3.3, the Pre-Application Report shall include the following information:

1.3.2.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.3.2.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.3.2.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.3.2.4 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.3.2.5 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.3.2.6 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.3.2.7 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

1.3.2.8 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.3.2.9 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.3.2.10 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.3.2.11 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.3.2.12 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.3.2.13 Other information regarding an Affected System the Utility deems relevant to the Interconnection Customer.

1.3.3 The Pre-Application Report need only include existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Utility cannot complete all or some of the Pre-Application Report due to lack of available data, the Utility shall provide the Interconnection Customer with a Pre-Application Report that includes the data that is readily available. Notwithstanding any of the provisions of this section, the Utility shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting. Further, the total capacity provided in Section 1.3.2.1 does not indicate that an interconnection of aggregate generation up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the Pre-Application Report may become outdated at the time of the submission of the complete Interconnection Request.

1.4 Interconnection Request

1.4.1 The Interconnection Customer shall submit its Interconnection Request to the Utility, and the Utility shall notify the Interconnection Customer confirming receipt of the Interconnection Request within three (3) Business Days of receiving the Interconnection Request.

The Interconnection Request Application Form shall be date- and time-stamped upon receipt of the following:

1.4.1.1 A substantially complete Interconnection Request Application Form contained in Attachment 2 submitted by a valid legal entity registered with the North Carolina Secretary of State, and signed by the Interconnection Customer.

1.4.1.2 The applicable fee or Interconnection Request Deposit. The applicable fee is specified in the Interconnection Request Application Form and applies to a certified inverter-based Generating Facility no larger than 20 kW reviewed under Section 2 and to any certified Generating Facility no larger than the capacity specified in Section 3.1 to be evaluated under the Section 3 Fast Track Process.

For all Generating Facilities that do not qualify for the 20 kW Inverter Process or the Fast Track Process, fail the Fast Track and Supplemental Review Process under Section 3.0 and are to be evaluated under the Section 4 Study Process, an Interconnection Request Deposit is required. The Interconnection Request Deposit shall equal \$20,000 plus one dollar (\$1.00) per kWac of capacity specified in the Interconnection Request Application Form, not to exceed an aggregate Interconnection

Request Deposit of $100,000. The Interconnection Request Deposit is intended to cover the Utility's reasonably anticipated costs for conducting the System Impact Study and the Facilities Study. Such deposit shall, however, be applicable towards the cost of all studies, Upgrades and Interconnection Facilities.

1.4.1.3 A Site Control Verification letter (sample included within Attachment 2).

1.4.1.4 A site plan indicating the location of the project, the property lines and the desired Point of Interconnection.

1.4.1.5 An electrical one-line diagram for the Generating Facility.

1.4.1.6 Inverter specification sheets for the Interconnection Customer's equipment that will be utilized.

1.4.2 The original date- and time-stamp applied to the Interconnection Request Application Form shall be accepted as the qualifying date- and time-stamp for the purposes of establishing Queue Position and any timetable in these procedures.

1.4.3 The Utility shall notify the Interconnection Customer within ten (10) Business Days of the receipt of the Interconnection Request Application Form as to whether the Form and initial supporting documentation specified in Sections 1.4.1.1 through 1.4.1.6 are complete or incomplete. An Interconnection Request will be deemed complete upon submission of the listed information in Section 1.4.1 to the Utility.

1.4.4 If the Interconnection Request Application Form and/or the initial supporting documentation is incomplete, the Utility shall provide, along with notice that the information is incomplete, a written list detailing all information that must be provided. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. If the Interconnection Customer does not provide the listed information or a request for an extension of time, not to exceed ten (10) additional Business Days, within the deadline, the Interconnection Request will be deemed withdrawn.

1.5 Modification of the Interconnection Request

"Material Modification" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of the

Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.

1.5.1 Indicia of a Material Modification, include, but are not limited to:

1.5.1.1 A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

1.5.1.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.1.3 A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

1.5.1.4 A change of transformer connection(s) or grounding from that originally proposed;

1.5.1.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;

1.5.1.6 An increase of the AC output of a Generating Facility; or

1.5.1.6 A change reducing the AC output of the generating facility by more than 10%.

1.5.2 The following are not indicia of a Material Modification:

1.5.2.1 A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.

1.5.2.2 A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.2.3 An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;

1.5.2.4 A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.

1.5.3 To the extent Interconnection Customer proposes to modify any information provided in the Interconnection Request deemed complete by the Utility, the Interconnection Customer shall submit any such modifications to the Utility in writing. If the Utility determines that the proposed modification(s) constitutes a Material Modification, the Utility shall notify the Interconnection Customer in writing within ten (10) Business Days that the modification is a Material Modification and the Interconnection Request shall be withdrawn from the Queue unless the Interconnection Customer withdraws the proposed Material Modification within 15 Calendar Days of receipt of the Utility's written notification. If the modification is determined by the Utility not to be a Material Modification, then the Utility shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its Queue Number. Any dispute as to the Utility's determination that a modification constitutes a Material Modification shall proceed in accordance with Section 6.2 below.

1.5.4 Modification Inquiry

1.5.4.1 Prior to making any modification, the Interconnection Customer may first submit an informal modification inquiry in writing that requests the Utility to evaluate whether such modification to the original or most recent Interconnection Request is a Material Modification. The Interconnection Customer shall provide specific details on all changes that are to be considered by the Utility.

1.5.4.2 In response to Interconnection Customer's informal request, if the Utility evaluates the proposed modification(s) and determines that the changes are not Material Modifications, the Utility shall inform the Interconnection Customer in writing within ten (10) Business Days. If the Interconnection Customer wishes to proceed with the proposed modification(s), the Interconnection Customer shall submit a revised Interconnection Request Application Form that reflects the approved modifications.

1.6 Site Control

Documentation of site control shall be submitted to the utility with the Interconnection Request using the sample site control verification form included in the Interconnection Request in Attachment 3.

Site control may be demonstrated through:

1. Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility;

2. An option to purchase or acquire a leasehold site for such purpose; or

3. An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

Should Interconnection Customer's site control lapse at any point in time prior to interconnection and such lapse is brought to the attention of Utility, the Utility shall notify the Interconnection Customer in writing of the alleged lapse in site control. The Interconnection Customer shall have ten (10) Business Days from the posted date on the notice from the Utility to cure and submit documentation of re-established site control, where failure to cure the lapse will result in the Interconnection Request being deemed withdrawn.

1.7 Queue Number

1.7.1 The Utility shall assign a Queue Number pursuant to Section 1.4.2. The Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. Subject to Section 1.8, the Queue Number of each Interconnection Request shall also determine the order in which each Interconnection Request is studied.

1.7.2 Subject to the provisions of Sections 1.4, 1.5, and 1.6, Generating Facilities shall retain the Queue Number assigned to their initial Interconnection Request throughout the review process, including where moving through the processes covered by Sections 2, 3, and 4.

1.8 Interdependent Projects

"Interdependent Customer" (or "Project"), "Project A" and "Project B" are defined in the glossary of terms (see Attachment 1).

1.8.1 Upon an Interconnection Customer's submission of a Section 1.4 Interconnection Request for the Section 3 Fast Track Process or Section 4 Study Process, the Utility shall review the Interconnection Request and make a preliminary determination whether any known Interdependency exists between the Interconnection Customer's proposed Generating Facility and any other Interconnection Customer with a lower Queue Number. Any preliminary determination by the Utility that the Generating Facility does not create an Interdependency will result in the Interconnection Request being preliminarily designated as a Project A and the Utility shall proceed immediately to either the Section 3 Fast Track Process or the Section 4 Study process, as applicable. The Utility shall advise the Interconnection Customer at the Section 4.2 Scoping Meeting, if requested by the Interconnection Customer, regarding its preliminary determination of whether Interdependency would be created by the Generating Facility. A Generating Facility designated and reviewed for system impacts as a Project A may still be determined to create an Interdependency and may be designated by the Utility as an Interdependent Project during the Section 4.3 System Impact Study Process. Once the System Impact Study report is issued by the Utility designated a Generating Facility as a Project A for purposes of the Section 4.4 Facilities Study, the Interconnection Request shall retain this designation without change.

1.8.2 If the Utility determines that that the Interconnection Customer's proposed Generating Facility is Interdependent with one (1) other Interconnection Request with a lower Queue Number, the Utility shall notify the Interconnection Customer at the Section 4.2 Scoping Meeting that the Interconnection Request is designated as a Project B.

1.8.2.1 Following the Section 4.2 Scoping Meeting and execution of the System Impact Study Agreement, the Project B shall proceed to the Section 4.3 System Impact Study process. Project B shall receive a System Impact Study report that assumes the interdependent Project A Interconnect Request with the lower Queue Number completes construction and interconnection and another System Impact Study report that assumes the interdependent Project A Interconnect Request with the lower Queue Number is not constructed and is withdrawn.

1.8.2.2 The Utility shall not proceed to a Project B Facilities Study until after the Project B Interconnection Customer returns a signed Facilities Study Agreement to the Utility and the Utility has issued the Section 4.4.4 Facilities Study report for the Interdependent Project A. The Project B Interconnection Customer shall then have the option of whether to proceed with a Facility Study, or wait until the Interdependent Project A executes a Final Interconnection Agreement and makes payment for any required Upgrade, Interconnection Facilities, and other charges under Section 5.2. If the Project B Interconnection Customer with a signed Facilities Study Agreement prior to Interdependent Project A committing to Section 5 construction, the Project B's Facility Study shall assume that the interdependent Project A Interconnection Request with the lower Queue Number completes construction and interconnection. If Project A is later cancelled prior to the Project A Interconnection Customer making payment for the required Upgrade, the Utility will revise the Project B Facility Study at Project B Interconnection Customer's expense. If Project B Interconnection Customer chooses to wait to request the Project B Facility Study, Project B is not required to adhere to the timeline in Section 4.4.1 until Project A has signed an Interconnection Agreement and paid the payment charge specified in Section 5.2.4 of these Interconnection Procedures or withdrawn.

1.8.3 If the Utility determines that that the Interconnection Customer's proposed Generating Facility is Interdependent with more than one (1) other Interconnection Request with lower Queue Numbers, the Utility shall make a preliminary determination and notify the Interconnection Customer at the Section 4.2 Scoping Meeting, if requested by the Interconnection Customer, describing generally the number and type of Interdependencies of Interconnection Requests with lower Queue Numbers.

1.8.3.1 The Utility shall not study a project if it is interdependent with more than one project, each of which has a lower Queue Number. The utility will study a project when interdependency with only one lower Queue Number project exists. The removal of interdependency with multiple projects may be the result of 1) upgrades to the Utility System which eliminate the cause of the interdependency, 2) withdrawal of interdependent project(s) with lower Queue Numbers, or 3) a lower Queue Number project signing an Interconnection Agreement and making payments required in Section 5.2.4.

1.8.3.2 Within five (5) Business Days of an Interconnection Request becoming a Project B Interconnection Request that is Interdependent with only one (1) other Interconnection Request with a lower Queue Number, the Utility shall schedule the Section 4.2 Scoping Meeting and provide the new Project B an executable System Impact Study Agreement. Upon being designated by the Utility as a Project B the Interconnection Customer's Queue Number will be used to determine the order in which the Interconnection Request is studied under section 4.3 relative to all other Interconnection Requests.

1.9 Interconnection Requests Submitted Prior to the Effective Date of these Procedures

Other than as set forth in Section 1.1.3, nothing in this Standard affects an Interconnection Customer's Queue Number assigned before the effective date of these procedures. Interconnection Requests which have received a System Impact Study report as of the effective date of these procedures that did not identify any interdependency with another project shall be deemed a Project A.

Any Interconnection Requests for which the Utility has not completed the System Impact Study and issued a System Impact Study report to the Interconnection

Customer as of the effective date of these procedures shall be reviewed for Interdependency pursuant to Section 1.8.

Should an Interconnection Customer fail to comply with Section 1.1.3 following receipt of written notice specifying how the Interconnection Customer failed to comply and the expiration of an opportunity to cure by the close of business on the tenth (10th) Business Day following the posted date of such notice to cure, such Interconnection Customer will lose its Queue Number and such Interconnection Request shall be deemed withdrawn.

Section 2. Optional 20 kW Inverter Process for Certified Inverter-Based Generating Facilities No Larger than 20 kW

2.1 Applicability

The 20 kW Inverter Process is available to an Interconnection Customer proposing to interconnect its inverter-based Generating Facility with the Utility's System if the Generating Facility is no larger than 20 kW and if the Interconnection Customer's proposed Generating Facility meets the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

The Utility may require the Interconnection Customer to install a manual load-break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the Interconnection Customer. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code) and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications (see also Section 6.16).

2.2 Interconnection Request

The Interconnection Customer shall complete the Interconnection Request Application Form for a certified inverter-based Generating Facility no larger than 20 kW in the form provided in Attachment 6 and submit it to the Utility, together with the non-refundable processing fee specified in the Interconnection Request Application Form and the documentation required pursuant to Section 1.4.1.

2.2.1 The Utility shall verify that the Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process. (See Section 3.2.1.) The Utility has 15 Business Days to complete this process. Unless the Utility determines and demonstrates that the Generating Facility cannot be interconnected safely and reliably, the Utility shall approve the Interconnection Request upon fulfillment of all requirements in Section 1.4 and return the Interconnection Request Application Form to the Interconnection Customer.

2.2.1.2 If the proposed interconnection passes the screens but the Utility determines that minor Utility construction is required to interconnect the Generating Facility to the Utility's system, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with the Interconnection Request Application Form within 15 Business Days after the determination.

2.2.1.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

2.2.2 Screens failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the Utility cannot determine that the Generating Facility may be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Interconnection Customer with detailed information on the reasons for failure in writing within ten (10) Business Days. In addition, the Utility shall either:

2.2.2.1 Notify the Interconnection Customer in writing that the Utility is continuing to evaluate the Generating Facility under Section 3.4 Supplemental Review if the Utility concludes that the Supplemental Review might determine that the Generating Facility could continue to qualify for interconnection pursuant to Fast Track: or

2.2.2.2 Offer to continue evaluating the Interconnection Request under the Section 4 Study Process.

2.3 Certificate of Completion

2.3.1 After installation of the Generating Facility, the Interconnection Customer shall submit the Certificate of Completion in the form provided in Attachment 6 to the Utility. Prior to parallel operation, the Utility may inspect the Generating Facility for compliance with standards including a witness test and the scheduling of an appropriate metering replacement, if necessary.

2.3.2 The Utility shall notify the Interconnection Customer in writing that interconnection of the Generating Facility is authorized. If the witness test is not satisfactory, the Utility has the right to disconnect the Generating Facility. The Interconnection Customer has no right to operate in parallel with the Utility until a witness test has been performed, or previously waived on the Interconnection Request. The Utility is obligated to complete this witness test within ten (10) Business Days of the receipt of the Certificate of Completion. If the Utility does not inspect within ten (10) Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

2.3.3 Interconnection and parallel operation of the Generating Facility is subject to the Terms and Conditions stated in Attachment 6 of these procedures.

2.4 Contact Information

The Interconnection Customer must provide its contact information. If another entity is responsible for interfacing with the Utility, that contact information must also be provided on the Interconnection Request Application Form.

2.5 Ownership Information

The Interconnection Customer shall provide the legal name(s) of the owner(s) of the Generating Facility.

2.6 UL 1741 Listed

The Underwriters' Laboratories (UL) 1741 standard (Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources) addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a nationally recognized testing laboratory that verifies compliance with UL 1741. This "listing" is then marked on the equipment and supporting documentation.

Section 3. Optional Fast Track Process for Certified Generating Facilities

3.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility's capacity does not exceed the size limits identified in the table below. Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Generating Facility will pass the Fast Track screens in Section 3.2 below or the Supplemental Review screens in Section 3.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Generating Facilities connecting to lines greater or equal to 35 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. For inverter-based systems, only certified inverter-based systems are eligible for the Fast Track Process and the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds set forth in the table below. In addition to the size threshold, the Interconnection Customer's proposed Generating Facility must meets the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has to have reviewed the design or tested the proposed Generating Facility and be satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems[1]		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[2] and ≤ 2.5 Electrical Circuit Miles from Substation[3]
< 5 kV	≤ ~~100~~ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 35 kV	≤ 2 MW	≤ 2 MW

1 Must be an UL certified inverter.

2 For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

3 An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

3.2 Initial Review

Within 15 Business Days after the Utility notifies the Interconnection Customer it has received a complete Interconnection Request pursuant to Section 1.4, the Utility shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Utility's determinations under the screens.

3.2.1 Screens

3.2.1.1 The proposed Generating Facility's Point of Interconnection must be on a portion of the Utility's Distribution System.

3.2.1.2 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.[1]

3.2.1.3 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 90% of the circuit and/or bank minimum load at the substation.

3.2.1.4 All synchronous and induction machines must be connected to a distribution circuit where the local minimum load to generation ratio on the circuit line segment is larger than 3 to 1. A 3-1 load to generation ratio screen utilizes actual recorded data that is sufficient to establish the minimum threshold.

3.2.1.5 For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

3.2.1.6 The proposed Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

3.2.1.7 The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

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[1] A. If the point of common coupling is downstream of a line recloser, include those medium voltage (MV) line sections from the recloser to the end of the feeder. If the 15% criterion is passed for aggregate distributed generation and peak load at first upstream recloser, then the screen is passed.

B. If the point of common coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak load for the whole feeder, then the screen is passed.

3.2.1.8 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service to be provided to the Interconnection Customer, including line configuration and the transformer connection for the purpose of limiting the potential for creating over-voltages on the Utility's System due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen
Three-phase, four wire	Effectively-grounded three-phase or single phase, line-to-neutral	Pass Screen

3.2.1.9 If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating.

3.2.1.10 If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

3.2.1.11 The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

3.2.2 Screen Results

3.2.2.1 If the proposed interconnection passes the screens and requires no construction by the Utility on its own System, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.2 If the proposed interconnection passes the screens and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect the Generating Facility to the Utility's system, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

3.2.2.4 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, and requires no construction by the Utility on its own System, the Utility shall provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.5 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect with the Generating Facility, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.6 If the proposed interconnection fails the screens, and the Utility does not or cannot determine from the initial review that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Utility shall provide the Interconnection Customer with the opportunity to attend a customer options meeting as described in Section 3.3 below.

3.3 Customer Options Meeting

If the Utility determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Utility shall notify the Interconnection Customer of that determination within five (5) Business Days after the determination, and provide copies of all data and analyses underlying its conclusion. Within ten (10) Business Days of the Utility's determination, the Utility shall offer to convene a customer options meeting to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Generating Facility to be connected safely and reliably. At the time of notification of the Utility's determination, or at the customer options meeting, the Utility shall:

3.3.1 Offer to perform facility modifications or minor modifications to the Utility's System (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Utility's System. The Interconnection Customer shall have ten (10) Business Days to agree to pay for the modifications to the Utility's electric system or the Interconnection Request shall be deemed to be withdrawn. If the Interconnection Customer agrees to pay for the modifications to the Utility's electric system, the Utility will provide the Interconnection Customer with an executable Interconnection Agreement within ten (10) Business Days of the Interconnections Customer's agreement to pay; or

3.3.2 Offer to perform a supplemental review ~~under~~ in accordance with Section 3.4 ~~if the Utility concludes that the supplemental review might determine that the Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process,~~ and provide a non-binding good faith estimate of the costs of such review. The Interconnection Customer shall have ten (10) Business Days to accept the Utility's offer to perform a Supplemental Review and post any deposit requirement for the Supplemental Review, or the Interconnection Request shall be deemed to be withdrawn; or

3.3.3 ~~Offer to continue~~Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the Section 4 Study Process. The Interconnection Customer shall have ten (10) Business Days to agree in writing to its Interconnection Request continuing to be evaluated under the Section 4 Study Process, and post any deposit requirement for the Study Process, or the Interconnection Request shall be deemed to be withdrawn.

3.4 Supplemental Review

3.4.1 If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit for the estimated costs or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Utility will return such excess within 20 Business Days of the invoice without interest.

3.4.2 The Interconnection Customer may specify the order in which the Utility will complete the screens in Section 3.4.4.

3.4.3~~1~~ Within ~~ten~~ thirty (~~10~~30) Business Days following receipt of the deposit for a supplemental review, the Utility shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Utility's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Utility shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in Section 3.4.3.1, within two (2) Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this Section 3.4.3; (2) terminate the supplemental review and continue evaluating the Generating Facility under Section 4; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer. ~~will determine if the Generating Facility can be interconnected safely and reliably.~~

3.4.~~1~~3.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Utility shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 3.4.3.~~If so, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days.~~

3.4.3.1.1 The type of generation used by the proposed Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 3.4.3.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

3.4.3.1.2 When this screen is being applied to a Generating Facility that serves some station service load, only the net injection into the Utility's electric system will be considered as part of the aggregate generation.

3.4.3.1.3 Utility will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

3.4.~~1~~3.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.~~If so, and Interconnection Customer facility modifications are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within 15 Business Days after confirmation that the Interconnection Customer has agreed to make the necessary modifications at the Interconnection Customer's cost.~~

3.4.~~1~~3.3 Safety and Reliability Screen: The location of the proposed Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Utility shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.~~If so, and minor modifications to the Utility's System are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days that requires the Interconnection Customer to pay the costs of such System modifications prior to interconnection.~~

~~If not, the Interconnection Request will continue to be evaluated under the Section 4 Study Process, provided the Interconnection Customer indicates it wants to proceed and submits the required deposit within 15 Business Days.~~

3.4.3.1.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

3.4.3.3.2 Whether the loading along the line section uniform or even.

3.4.3.3.3 Whether the proposed Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

3.4.3.3.4 Whether the proposed Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

3.4.3.3.5 Whether operational flexibility is reduced by the proposed Generating Facility, such that transfer of the line section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

3.4.3.3.6 Whether the proposed Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

3.4.4 If the proposed interconnection passes the supplemental screens in Sections 3.4.3.1, 3.4.3.2, and 3.4.3.3 above, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in Sections 3.4.4.1 and 3.4.4.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the Section 4 Study Process consistent with Section 3.4.4.3 below.

3.4.4.1 If the proposed interconnection passes the supplemental screens in Sections 3.4.3.1, 3.4.3.2, and 3.4.3.3 above and does not require construction of facilities by the Utility on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

3.4.4.2 If Interconnection Facilities or Minor System Modifications to the Utility's system are required for the proposed interconnection to pass the supplemental screens in Sections 3.4.3.1, 3.4.3.2, and 3.4.3.3 above, and the Interconnection Customer agrees to pay for the modifications to the Utility's electric system, the interconnection agreement, along with a non-binding good faith estimate for the Interconnection Facilities and/or Minor System Modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

3.4.4.3 If the proposed interconnection would require more than Interconnection Facilities or Minor System Modifications to the Utility's system to pass the supplemental screens in Sections 3.4.3.1, 3.4.3.2, and 3.4.3.3 above, the Utility shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the Section 4 Study Process unless the Interconnection Customer withdraws its Generating Facility.

Section 4. Study Process

4.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility exceeds the size limits for the Section 3 Fast Track Process, is not certified, or is certified but did not pass the Fast Track Process or the 20 kW Inverter Process. The Interconnection Customer may be required to submit additional documentation, as may be requested by the Utility in writing, during the Study Process.

4.2 Scoping Meeting

4.2.1 A scoping meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Utility and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. The scoping meeting may be omitted by mutual agreement.

4.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Utility should perform a System Impact Study, a Facilities Study, or proceed directly to an Interconnection Agreement.

4.2.3 If the Utility, after consultation with the Interconnection Customer, determines that the project should proceed to a System Impact Study or Facilities Study, the Utility shall provide the Interconnection Customer, no later than ten (10) Business Days after the scoping meeting, either a System Impact Study Agreement (Attachment 7) or a Facilities Study Agreement (Attachment 8), as appropriate, including an outline of the scope of the study or studies and a nonbinding good faith estimate of the cost to perform the study or studies, which cost shall be subtracted from the deposit outlined in Section 1.4.1.2.

4.2.4 If the Parties agree not to perform a System Impact Study or Facilities Study, but to proceed directly to an Interconnection Agreement, the Parties shall proceed to the Construction Planning Meeting as called for in Section 5.

4.3 System Impact Study

4.3.1 In order to retain its Queue Position, the Interconnection Customer must return a System Impact Study Agreement signed by the Interconnection Customer within 15 Business Days of receiving an executable System Impact Study Agreement as provided for in Section 4.2.3.

4.3.2 The scope of and cost responsibilities for a System Impact Study are described in the System Impact Study Agreement. The time allotted for completion of the System Impact Study shall be as set forth in the System Impact Study Agreement.

4.3.3 The System Impact Study shall identify and detail the electric system impacts that would result if the proposed Generating Facility were interconnected without project modifications or electric system modifications, or to study potential impacts, including, but not limited to, those identified in the scoping meeting. The System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the electric system, including the distribution and transmission systems, if required.

4.3.4 The System Impact Study report will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection.

4.3.5 The System Impact Study report will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary non-binding indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

4.3.6 If the Utility has determined that an Interdependency exists and the Project is designated as a Project B, the Project B Interconnection Request shall receive a System Impact Study report, addressing a scenario assuming Project A is constructed and a second scenario assuming Project A is not constructed.

4.3.7 After receipt of the System Impact Study report(s), the Interconnection Customer shall inform the Utility in writing if it wishes to withdraw the Interconnection Request and to request an accounting of any remaining deposit amount pursuant to Section 6.3.

4.3.8 If requested by the Interconnection Customer following delivery of the System Impact Study report, the Utility shall provide the Interconnection Customer an executable Interim Interconnection Agreement within ten (10) Business Days. The Interim Interconnection Agreement shall be identical in form and content to the Final Interconnection Agreement, but will not include Detailed Estimated Upgrade Charges, Detailed Estimated

Interconnection Facility Charge, Appendix 4 (Construction Milestone schedule listing tasks, dates and the party responsible for completing each task), and other information that otherwise would be determined in Section 5.

4.3.9 At the time the System Impact Study Report is provided to the Interconnection Customer, the Utility shall also deliver an executable Facilities Study Agreement to the Interconnection Customer. After receipt of the System Impact Study report and Facilities Study Agreement, when the Interconnection Customer is ready to proceed with the design and construction of the Upgrades and Interconnection Facilities, the Interconnection Customer shall return the signed Facilities Study Agreement to the Utility in accordance with Section 4.4 below.

4.4 Facilities Study

4.4.1 A solar Interconnection Customer must request a Facilities Study by returning the signed Facilities Study Agreement within 60 Calendar Days of the date the Facilities Study Agreement was provided. Any other Interconnection Customer must request a Facility Study by returning the signed Facilities Study Agreement within 180 Calendar Days of the date the Facilities Study Agreement was provided. Failure to return the signed Facilities Study Agreement within the foregoing applicable time period will result in the Interconnection Request being deemed withdrawn.

4.4.2 When an Interdependent Project A exists, a Project B Interconnection Request will not be required to comply with Section 4.4.1 until Project A has signed the Final Interconnection Agreement, and made payments and provided Financial Security as specified in Section 5.2 or withdrawn. If Project B has not provided written notice of its intent to proceed to a Facilities Study under Section 1.8.2.2, upon the Project A fulfilling the requirements in Section 5.2 or withdrawing the Interconnection Request, the Utility shall notify the Project B Interconnection Customer that it has the time specified in Section 4.4.1 to return the signed Facilities Study Agreement or the Interconnection Request shall be deemed withdrawn.

4.4.3 The scope of and cost responsibilities for the Facilities Study are described in the Facilities Study Agreement. The time allotted for completion of the Facilities Study is described in the Facilities Study Agreement.

4.4.4 The Facilities Study report shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the System Impact Studies and to allow the Generating Facility to be interconnected and operated safely and reliably.

4.4.5 The Utility shall design any required Interconnection Facilities and/or Upgrades under the Facilities Study Agreement. The Utility may contract with consultants to perform activities required under the Facilities Study Agreement. The Interconnection Customer and the Utility may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Utility, under the provisions of the Facilities Study Agreement. If the Parties agree to separately arrange for design and construction, and provided that critical infrastructure security and confidentiality requirements can be met, the Utility shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

Section 5. Interconnection Agreement and Scheduling

5.1. Construction Planning Meeting

5.1.1. Within ten (10) Business Days of receipt of the Facility Study report, the Interconnection Customer shall request a Construction Planning Meeting, where failure to comply shall result in the Interconnection Request being deemed withdrawn. The Construction Planning Meeting request shall be in writing and shall include the Interconnection Customer's reasonably requested date for completion of the construction of the Upgrades and Interconnection Facilities.

5.1.2. The Construction Planning Meeting shall be scheduled within ten (10) Business Days of the Section 5.1.1 request from the Interconnection Customer, or as otherwise mutually agreed to by the parties.

5.1.3. The purpose of the Construction Planning Meeting is to identify the tasks for each party and discuss and determine the milestones for the construction of the Upgrades and Interconnection Facilities. Agreed upon milestones shall be specific as to scope of action, responsible party, and date of deliverable and shall be recorded in the Final Interconnection Agreement (see Appendix 4 to Attachment 9) to be provided to Interconnection Customer pursuant to Section 5.2.1 below.

5.1.4. If the Utility cannot complete the installation of the required Upgrades and Interconnection Facilities within two (2) months of the Interconnection Customer's reasonably requested In-Service Date, the Interconnection Customer shall have the option of payment for work outside of normal business hours or hiring a Utility-approved subcontractor to perform the distribution Upgrades. Any Utility-approved subcontractor performance remains subject to Utility oversight during construction. The Utility shall make a list of Utility-approved subcontractors available to the Interconnection Customer promptly upon request.

5.2. Final Interconnection Agreement

5.2.1. Within fifteen (15) Business Days of the Construction Planning Meeting, the Utility shall provide an executable Final Interconnection Agreement containing the Detailed Estimated Upgrade Charges, Detailed Estimated Interconnection Facility Charge, Appendix 4 (Construction Milestone and payment schedule listing tasks, dates and the party responsible for completing each task), and other appropriate information, requirements, and charges. The Final Interconnection Agreement will replace any Interim Interconnection Agreement, which shall terminate upon execution of the Final Interconnection Agreement by the Interconnection Customer and the Utility.

5.2.2. Within ten (10) Business Days of receiving the Final Interconnection Agreement, the Interconnection Customer must execute and return the Final Interconnection Agreement, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.2.3. After the Parties execute the Final Interconnection Agreement, the Utility shall return a copy of the Final Interconnection Agreement to the Interconnection Customer and interconnection of the Generating Facility shall proceed under the provisions of the Final Interconnection Agreement.

5.2.4. The Final Interconnection Agreement shall specify milestones for payment for Upgrades and Interconnection facilities and/or, provision of Financial Security for Interconnection facilities, if acceptable to the Utility, that are required prior to the start of design and construction of Upgrades and Interconnection Facilities. Payment and Financial Security must be received by close of business sixty (60) Calendar Days after the date the Interconnection Agreement is delivered to the Interconnection Customer for signature, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.3 Interconnection Construction

Construction of the Upgrades and Interconnection Facilities will proceed as called for in the Final Interconnection Agreement and Appendices.

Section 6. Provisions that Apply to All Interconnection Requests

6.1 Reasonable Efforts

The Utility shall make reasonable efforts to meet all time frames provided in these procedures unless the Utility and the Interconnection Customer agree to a different schedule. If the Utility cannot meet a deadline provided herein, it shall at its earliest opportunity notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

6.2 Disputes

6.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this section. ~~Where an Interconnection Customer seeks to resolve a dispute involving its Queue Number according to the provisions of this section, any disputed loss of Queue Number shall not be final until Interconnection Customer abandons the process set out in this section or a final Commission order is entered.~~

6.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute~~. Such Notice shall describe in detail the nature of the dispute.~~ containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the procedures under this article. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the interconnection agreement or Interconnection Application, if there is no interconnection agreement. A copy of the notice shall also be sent to Interconnection Ombudsperson.

The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

6.2.3 If the dispute is principally related to one or both Parties' compliance with timelines specified in the Interconnection Standard or associated agreements, the Parties shall seek assistance from Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days. ~~If the dispute has not been resolved within ten (10) Business Days after receipt of the Notice, either Party may contact the Public Staff for assistance in informally resolving the dispute. If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the Commission.~~

6.2.4 If the dispute is not principally about one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any

Utility interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.~~Each Party agrees to conduct all negotiations in good faith.~~

6.2.5 If a resolution is not reached in thirty (30) Business Days from the date of the notice, either (1) a Party may request to continue negotiations for an additional twenty (20) Business Days or (2) the Parties may by mutual agreement make a written request for mediation to the Interconnection Ombudsperson. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

6.2.6 If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the Commission's formal complaint process.

6.2.7 At any time, either Party may file a complaint before the Commission pursuant to Commission rules.

6.2.8 If neither Party elects to seek assistance from the Commission, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

6.3 Withdrawal of An Interconnection Request

6.3.1 An Interconnection Customer may withdraw an Interconnection Request at any time prior to executing a Final Interconnection Agreement by providing the Utility with a written request for withdrawal.

6.3.2 An Interconnection Request shall be deemed withdrawn if the Interconnection Customer fails to meet its obligations specified in the Interconnection Procedures, System Impact Study Agreement or Facility Study Agreement or to take advantage of any express opportunity to cure.

6.3.3 Within 90 Calendar Days of any voluntary or deemed withdrawal of the Interconnection Request, the Utility will provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such work performed, and (2) the Interconnection Customer's previous aggregate Interconnection Facility Request Deposit payments to the Utility for such work. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due within ten (10) Business Days and the Interconnection Customer shall make payment to the Utility within 30 Calendar Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within ~~30 Calendar~~ten (10) Business Days of the final accounting report.

6.4 Interconnection Metering

Any metering necessitated by the use of the Generating Facility shall be installed at the Interconnection Customer's expense in accordance with all applicable regulatory requirements or the Utility's specifications.

6.5 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. If the Interconnection Customer is not proceeding under Section 2.3.2, the Utility must be given at least ten (10) Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

6.6 Confidentiality

6.6.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

6.6.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

6.6.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

6.6.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

6.6.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

6.6.4 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

6.7 Comparability

The Utility shall receive, process, and analyze all Interconnection Requests received under these procedures in a timely manner, as set forth in these procedures. The Utility shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facility is owned or operated by the Utility, its subsidiaries or affiliates, or others.

6.8 Record Retention

The Utility shall maintain for three (3) years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

6.9 Coordination with Affected Systems

The Utility shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable studies within the time frame specified in these procedures. The Utility will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection

Customer will cooperate with the Utility in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Utility which may be an Affected System shall cooperate with the Utility with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

6.10 Capacity of the Generating Facility

6.10.1 If the Interconnection Request is for a Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices, unless otherwise agreed to by the Utility and the Interconnection Customer.

6.10.2 ~~The Interconnection Request shall be evaluated using~~For the purposes of this Standard, the capacity of the Generating Facility shall be considered the maximum rated capacity of the Generating Facility, except where the gross generating capacity of the Generating Facility is limited (e.g., through the use of a control system, power relay(s), or other similar device settings or adjustments as mutually agreed upon by the Utility and Interconnection customer, and which agreement shall not be unreasonably withheld), the Generating Facility's capacity shall be considered the Maximum Generating Capacity specified by the Interconnection Customer in the Interconnection Request. The Maximum Generating Capacity approved in the study process will subsequently be included as a limitation in the Interconnection Agreement. ~~unless otherwise agreed to by the Utility and the Interconnection Customer.~~

6.11 Sale of a Generation Facility

6.11.1 The Interconnection Customer shall notify the Utility of the pending sale of a proposed Generation Facility in writing. The Interconnection Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generation Facility to a new legal entity, or a change of control of the existing legal entity.

The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generation Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing, and submit an Interconnection Request requesting transfer control or change of ownership together with the change of ownership fee listed in Attachment 2.

6.11.2 Existing Interconnection Agreements are non-transferable. If the Generation Facility is sold to a new legal entity, a new Interconnection Agreement must be executed by the new legal entity prior to the interconnection or for the continued interconnection of the Generating

Facility to the Utility's system. The Utility shall not withhold or delay the execution of an Interconnection Agreement with the new owner provided the Generation facility or proposed Generation facility complies with requirements of 6.11.

6.11.3 The technical requirements in the Interconnection Agreement shall be grandfathered for subsequent owners as long as (1) the Generating Facility's maximum rated capacity has not been changed; (2) the Generating Facility has not been modified so as to change its electrical characteristics; and (3) the interconnection system has not been modified.

6.12 Isolating or Disconnecting the Generating Facility

6.12.1 The Utility may isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System when necessary in order to construct, install, repair, replace, remove, investigate or inspect any of the Utility's equipment or part of Utility's System; or if the Utility determines that isolation of the Interconnection Customer's premises and/or Generating Facility from the Utility's System is necessary because of emergencies, forced outages, force majeure or compliance with prudent electrical practices.

6.12.2 Whenever feasible, the Utility shall give the Interconnection Customer reasonable notice of the isolation of the Interconnection Customer's premises and/or Generating Facility from the Utility's System.

6.12.3 Notwithstanding any other provision of this Standard, if at any time the Utility determines that the continued operation of the Generating Facility may endanger either (1) the Utility's personnel or other persons or property or (2) the integrity or safety of the Utility's System, or otherwise cause unacceptable power quality problems for other electric consumers, the Utility shall have the right to isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System.

6.12.4 The Utility may disconnect from the Utility's System any Generating Facility determined to be malfunctioning, or not in compliance with this Standard. The Interconnection Customer must provide proof of compliance with this Standard before the Generating Facility will be reconnected.

6.13 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

6.14 Indemnification

The Parties shall at all times indemnify, defend and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.15 Insurance

The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

6.15.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

6.15.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

6.15.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

6.15.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

6.16 Disconnect Switch

The Utility may require the interconnection Customer to install a manual load-break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the interconnection Customer. The switch must have padlock provisions for locking in the open position. The switch must be visible to, and accessible to Utility personnel. The switch must be in close proximity to, and on the Interconnection Customer's side of the point of electrical interconnection with the Utility's system. The switch must be labeled "Generator Disconnect Switch." The switch may isolate the Interconnection Customer and its associated load from the Utility's System or disconnect only the Generator from the Utility's System and shall be accessible to the Utility at all times. The Utility, in its sole discretion, determines if the switch is suitable and necessary. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code, and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications.

6.17 Certification Codes and Standards

Attachment 4 specifies codes and standards the Generating Facility must comply with.

6.18 Certification of Generator Equipment Packages

Attachment 5 specifies the certification requirements for the Generating Facility.

ATTACHMENT 1

Glossary of Terms

20 kW Inverter Process - The procedure for evaluating an Interconnection Request for a certified inverter-based Generating Facility no larger than 20 kW that uses the Section 3 screens. The application process uses an all -in-one document that includes a simplified Interconnection Request Application Form, simplified procedures, and a brief set of Terms and Conditions. (See Attachment 6.)

Affected System - An electric system other than the Utility's System that may be affected by the proposed interconnection. The owner of an Affected System might be a Party to the Interconnection Agreement or other study agreements needed to interconnect the Generating Facility.

Applicable Laws and Regulations - All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Auxiliary Load -- The term "Auxiliary Load" shall mean power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, exciters, etc.)

Business Day - Monday through Friday, excluding State Holidays.

Calendar Days -- Sunday through Saturday, including all holidays.

Commission - The North Carolina Utilities Commission.

Default - The failure of a breaching Party to cure its breach under the Interconnection Agreement.

Detailed Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is based on field visits and/or detailed engineering cost calculations and is presented in the Facility Study report and Final Interconnection Agreement. This charge is not final.

Detailed Estimated Upgrade Charge - The estimated charge for Upgrades that is based on field visits and/or detailed engineering cost calculations and is presented in the Facility Study report and Final Interconnection Agreement.

Distribution System - The Utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades - The additions, modifications, and upgrades to the Utility's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the service necessary to allow the Generating Facility to operate in parallel with the Utility and to inject electricity onto the Utility's System. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process - The procedure for evaluating an Interconnection Request for a certified Generating Facility no larger than 2 MW that meets the eligibility requirements of Section 3.1, customer options meeting, and optional supplemental review.

Final Interconnection Agreement – The Interconnection Agreement that specifies the Detailed Estimated Upgrade Charge, Detailed Interconnection Facility Charge, mutually agreed upon Milestones, etc. and terminates and replaces the Interim Interconnection Agreement.

Financial Security – A letter of credit or other financial arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina that is sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility's Interconnection Facilities. Where appropriate, the Utility may deem Financial Security to exist where its credit policies show that the financial risks involved are de minimus, or where the Utility's policies allow the acceptance of an alternative showing of credit-worthiness from the Interconnection Customer.

Generating Facility - The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority - Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Utility, or any affiliate thereof.

In-Service Date – The date upon which the construction of the Utility's facilities is completed and the facilities are capable of being placed into service.

Interconnection Customer - Any valid legal entity, including the Utility, that proposes to interconnect its Generating Facility with the Utility's System.

Interconnection Facilities – Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's System. Interconnection Facilities are sole use facilities and shall not include Upgrades.

Interconnection Facilities Delivery Date – The Interconnection Facilities Delivery Date shall be the date upon which the Utility's Interconnection Facilities are first made operational for the purposes of receiving power from the Interconnection Customer.

Interconnection Request - The Interconnection Customer's request, in accordance with these procedures, to interconnect a new Generating Facility, or to change the capacity of, or make a Material Modification to, an existing Generating Facility that is interconnected with the Utility's System.

Interdependent Customer (or Interdependent Project) means an Interconnection Customer (or Project) whose Upgrade or Interconnection Facilities requirements are impacted by another Generating Facility, as determined by the Utility.

Interim Interconnection Agreement – The Interconnection Agreement that specifies the Preliminary Estimated Interconnection Facilities Charge, Preliminary Estimated Upgrade Charge, excludes Milestones, and must be cancelled and replaced with a Final Interconnection Agreement.

Line Section – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

"**Material Modification**" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of the Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.

Indicia of a Material Modification, include, but are not limited to:

- A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

- A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

- A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

- A change of transformer connection(s) or grounding from that originally proposed;

- A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;

- An increase of the AC output of a Generating Facility; or

- A change reducing the AC output of the generating facility by more than 10%.

The following are not indicia of a Material Modification:

- A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.

- A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

- An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;

- A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.

Maximum ~~Physical Export Capability~~Generating Capacity Requested - The term shall mean the maximum continuous electrical output of the Generating Facility at any time ~~at a power factor of approximately unity~~ [A2]as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period.

Month – The term "Month" means the period intervening between readings for the purpose of routine billing, such readings usually being taken once per month.

Nameplate Capacity – The term "Nameplate Capacity" shall mean the manufacturer's nameplate rated output capability of the generator. For multi-unit generator facilities, the "Nameplate Capacity" of the facility shall be the sum of the individual manufacturer's nameplate rated output capabilities of the generators.

Net Capacity – The term "Net Capacity" shall mean the Nameplate Capacity of the Customer's generating facilities, less the portion of that capacity needed to serve the Generating Facility's Auxiliary Load.

Net Power - The term "Net Power" shall mean the total amount of electric power produced by the Customer's Generating Facility less the portion of that power used to supply the Generating Facility's Auxiliary Load.

Network Upgrades - Additions, modifications, and upgrades to the Utility's Transmission System required to accommodate the interconnection of the Generating Facility to the Utility's System. Network Upgrades do not include Distribution Upgrades.

North Carolina Interconnection Procedures – The term "North Carolina Interconnection Procedures" shall refer to the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections as approved by the North Carolina Utilities Commission.

Operating Requirements - Any operating and technical requirements that may be applicable due to Regional Reliability Organization, Independent System Operator, control area, or the Utility's requirements, including those set forth in the Interconnection Agreement.

Party or Parties - The Utility, Interconnection Customer, and possibly the owner of an Affected System, or any combination of the above.

Point of Interconnection - The point where the Interconnection Facilities connect with the Utility's System.

Preliminary Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is developed using unit costs and is presented in the System Impact Study report and Interim Interconnection Agreement. This charge is not based on field visits and/or detailed engineering cost calculations.

Preliminary Estimated Upgrade Charge - The estimated charge for Upgrades that is developed using unit costs and is presented in the System Impact Study report and Interim Interconnection Agreement. This charge is not based on field visits and/or detailed engineering cost calculations.

Project A - An Interconnection Customer that has a lower Queue Number than Interdependent Project B.

Project B - An Interconnection Customer that has a higher Queue Number than Interdependent Project A.

Public Staff - The Public Staff of the North Carolina Utilities Commission.

Queue Number – The number assigned by the Utility that establishes a Customer's Interconnection Request's position in the study queue relative to all other valid Interconnection Requests. A lower Queue Number will be studied prior to a higher Queue Number, except in the case of Interdependent Projects. The Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection.

Queue Position - The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, based on Queue Number.

Reasonable Efforts - With respect to an action required to be attempted or taken by a Party under the Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Standard - The interconnection procedures, forms and agreements approved by the Commission for interconnection of Generating Facilities to Utility Systems in North Carolina.

Study Process - The procedure for evaluating an Interconnection Request that includes the Section 4 scoping meeting, system impact study, and facilities study.

System - The facilities owned, controlled or operated by the Utility that are used to provide electric service in North Carolina.

Utility - The entity that owns, controls, or operates facilities used for providing electric service in North Carolina.

Transmission System - The facilities owned, controlled or operated by the Utility that are used to transmit electricity in North Carolina.

Upgrades - The required additions and modifications to the Utility's System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

NORTH CAROLINA
INTERCONNECTION REQUEST APPLICATION FORM

Utility: ______________________________

Designated Utility Contact: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: ________

Telephone Number: ______________________________

Fax: ______________________________

An Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customer who requests a North Carolina Utilities Commission jurisdictional interconnection must submit this Interconnection Request Application Form by hand delivery, mail, e-mail, or fax to the Utility.

Request for: Fast Track Process ____ Study Process ____
(All Generating Facilities larger than 2 MW must use the Study Process.)

Processing Fee or Deposit

<u>Fast Track Process – Non-Refundable Processing Fees</u>

- If the Generating Facility is 20 kW or smaller, the fee is $100.
- If the Generating Facility is larger than 20 kW but not larger than 100 kW, the fee is $250.
- If the Generating Facility is larger than 100 kW but not larger than 2 MW, the fee is $500.

<u>Study Process – Deposit</u>

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Utility an Interconnection Facilities Deposit Charge of $20,000 plus $1.00 per kW_{AC}.

Change in Ownership – Non-Refundable Processing Fee

If the Interconnection Request is submitted solely due to a transfer of ownership or change of control of the Generating Facility, the fee is $50.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ______________________________

Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: __________

County: ______________

Telephone (Day): __________ (Evening): ______________

Fax: ______________

Facility Location (if different from above):

Project Name: ______________________________

Address: ______________________________

City: ______________ State: __________ Zip: __________

County: ______________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: __________ Zip: __________

Telephone (Day) ______________ (Evening) ______________

Fax: ______________

Application is for: ______ New Generating Facility

______ Capacity Change to a Proposed or Existing Generating Facility

______ Change of Ownership of a Proposed or Existing Generating Facility to a new legal entity

______ Change of Control of a Proposed or Existing Generating Facility of the existing legal entity.

If capacity addition to existing Generating Facility, please describe: ______________

Will the Generating Facility be used for any of the following?

Net Metering? Yes _____ No _____

To Supply Power to the Interconnection Customer? Yes _____ No _____

To Supply Power to the Utility? Yes _____ No _____

To Supply Power to Others? Yes _____ No _____
(If yes, discuss with the Utility whether the interconnection is covered by the NC Interconnection Standard.)

Requested Point of Interconnection: ______________________________

Requested In-Service Date: ______________________________

For installations at locations with existing electric service to which the proposed Generating Facility will interconnect, provide:

Local Electric Service Provider*: ______________________________

Existing Account Number : ______________________________

*To be provided by the Interconnection Customer if the local electric service provider is different from the Utility

Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Generating Facility Information

Data applies only to the Generating Facility, not the Interconnection Facilities.

Prime Mover: Photovoltaic (PV) ____ Fuel Cell ___ Reciprocating Engine ___

Gas Turbine ___ Steam Turbine ___ Micro-turbine ___

Other ______________________________

Energy Source:

Renewable
- ❑ Solar – Photovoltaic
- ❑ Solar – thermal
- ❑ Biomass – landfill gas
- ❑ Biomass – manure digester gas
- ❑ Biomass – directed biogas
- ❑ Biomass – solid waste
- ❑ Biomass – sewage digester gas
- ❑ Biomass – wood
- ❑ Biomass – other (specify below)
- ❑ Hydro power – run of river
- ❑ Hydro power - storage
- ❑ Hydro power – tidal
- ❑ Hydro power – wave
- ❑ Wind
- ❑ Geothermal
- ❑ Other (specify below)

Non-Renewable
- ❑ Fossil Fuel - Diesel
- ❑ Fossil Fuel - Natural Gas (not waste)
- ❑ Fossil Fuel - Oil
- ❑ Fossil Fuel – Coal
- ❑ Fossil Fuel – Other (specify below)
- ❑ Other (specify below)

____

____

Type of Generator: Synchronous ____ Induction ____ Inverter ____

Total Generator Nameplate ~~Rating~~Capacity[A3]: __________ kW_{AC} (Typical) __________ kVAR

Interconnection Customer or Customer-Site Load:____________ kW_{AC} (if none, so state)

Interconnection Customer Generator Auxiliary Load: ____________ kW_{AC}

Typical Reactive Load (if known): ____________ kVAR

Maximum ~~Physical Export Capability~~Generating Capacity Requested: ____________ kW_{AC}
(The maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period)

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1.		
2.		
3.		
4.		
5.		

Generator (or solar panel information)

Manufacturer, Model & Quantity: ______________________________

Nameplate Output Power Rating in kW_{AC}: Summer __________ Winter __________

Nameplate Output Power Rating in kVA: Summer __________ Winter __________

Individual Generator Rated Power Factor: ________ Leading ________ Lagging

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request (if applicable): __________ Elevation: ________

Inverter Manufacturer, Model & Quantity: ______________________________

For solar projects provide the following information:

Latitude: ________ Degrees ________ Minutes North

Longitude: ________ Degrees ________ Minutes West

Orientation: ________ Degrees (Due South=180°)

☐ Fixed Tilt Array ☐ Single Axis Tracking Array ☐ Double Axis Tracking Array

Fixed Tilt Angle: ________ Degrees

Impedance Diagram - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide an Impedance Diagram. An Impedance Diagram may be required by the Utility for proposed interconnections at lower interconnection voltages. The Impedance Diagram shall provide, or be accompanied by a list that shall provide, the collector system impedance of the generation plant. The collector system impedance data shall include equivalent impedances for all components, starting with the inverter transformer(s) up to the utility level Generator Step-Up transformer.

Load Flow Data Sheet - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide a completed Power Systems Load Flow data sheet. A Load Flow data sheet may be required by the Utility for proposed interconnections at lower interconnection voltages.

Excitation and Governor System Data for Synchronous Generators - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be required at lower interconnection voltages. A copy of the manufacturer's block diagram may not be substituted.

Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: __________ Instantaneous ______ or RMS ________

Harmonics Characteristics: ____

Start-up requirements: ____

Inverter Short-Circuit Model Data

Model and parameter data required for short-circuit analysis is specific to each PV inverter make and model. All data to be provided in per-unit ohms, on the equivalent inverter MVA base.

Inverter Equivalent MVA Base: ___________ MVA

Values below are valid for initial 2 to 6 cycles:

Short-Circuit Equivalent Pos. Seq. Resistance (R1): _____________ p.u.

Short-Circuit Equivalent Pos. Seq. Reactance (XL1): _____________ p.u.

Short-Circuit Equivalent Neg. Seq. Resistance (R2): _____________ p.u.

Short-Circuit Equivalent Neg. Seq. Reactance (XL2): _____________ p.u.

Short-Circuit Equivalent Zero Seq. Resistance (R0): _____________ p.u.

Short-Circuit Equivalent Zero Seq. Reactance (XL0): _____________ p.u.

Special notes regarding short-circuit modeling assumptions:

____

____

Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________

(*) Neutral Grounding Resistor (if applicable): ____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: ______________ P.U.

Direct Axis Transient Reactance, X'_d: _________________ P.U.

Direct Axis Subtransient Reactance, X''_d: ______________ P.U.

Negative Sequence Reactance, X_2: __________________ P.U.

Zero Sequence Reactance, X_0: _____________________ P.U.

KVA Base: ________________

Field Volts: ________________________________

Field Amperes: ____________

Induction Generators:

Motoring Power (kW): ____________

I_2^2t or K (Heating Time Constant): ____________

Rotor Resistance, Rr: ____________

Stator Resistance, Rs: ____________

Stator Reactance, Xs: ____________

Rotor Reactance, Xr: ____________

Magnetizing Reactance, Xm: ____________

Short Circuit Reactance, Xd": ____________

Exciting Current: ____________

Temperature Rise: ____________

Frame Size: ____________

Design Letter: ____________

Reactive Power Required In Vars (No Load): ____________

Reactive Power Required In Vars (Full Load): ____________

Total Rotating Inertia, H: ____________ Per Unit on kVA Base

Note: Please contact the Utility prior to submitting the Interconnection Request to determine if the specified information above is required.

Interconnection Facilities Information

Will more than one transformer be used between the generator and the point of common coupling?

Yes ____ No ____ (If yes, copy this section and provide the information for each transformer used. This information must match the single-line drawing and transformer specification sheets.)

Will the transformer be provided by the Interconnection Customer? Yes ____ No _____

Transformer Data (if applicable, for Interconnection Customer-owned transformer):

Is the transformer: Single phase ___ Three phase ___ Size: _________ kVA

Transformer Impedance: _________ % on _________ kVA Base

If Three Phase:

Transformer Primary Winding ______________________________ Volts,

☐ Delta ☐ WYE, grounded neutral ☐ WYE, ungrounded neutral

Primary Wiring Connection

☐ 3-wire ☐ 4-wire, grounded neutral

Transformer Secondary Winding ______________________ Volts,

☐ Delta ☐ WYE, grounded neutral ☐ WYE, ungrounded neutral

Secondary Wiring Connection

☐ 3-wire ☐ 4-wire, grounded neutral

Transformer Tertiary Winding ______________________ Volts,

☐ Delta ☐ WYE, grounded neutral ☐ WYE, ungrounded neutral

Transformer Fuse Data (if applicable, for Interconnection Customer-owned fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: ________________ Type: __________ Size: _____ Speed: _______

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: ______________________

Load Rating (Amps): ____ Interrupting Rating (Amps): __________

Trip Speed (Cycles): ________

Interconnection Protective Relays (if applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.			
2.			
3.			
4.			
5.			
6.			

If Discrete Components:
(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer	Type:	Style/Catalog No.	Proposed Setting

Current Transformer Data (if applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________

Potential Transformer Data (if applicable):

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________

Manufacturer: ______________________ Type: ______________________

Accuracy Class: __________ Proposed Ratio Connection: ______________

General Information

1. One-line diagram
   Enclose site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes.
   - The one-line diagram should include the project owner's name, project name, project address, model numbers and nameplate sizes of equipment, including number and nameplate electrical size information for solar panels, inverters, wind turbines, disconnect switches, latitude and longitude of the project location, and tilt angle and orientation of the photovoltaic array for solar projects.
   - The diagram should also depict the metering arrangement required whether installed on the customer side of an existing meter ("net metering/billing") or directly connected to the grid through a new or separate delivery point requiring a separate meter.
   - List of adjustable set points for the protective equipment or software should be included on the electrical one-line drawing.
   - This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Generating Facility is larger than 50 kW.
   - Is One-Line Diagram Enclosed? Yes ___ No ___
2. Site Plan
   - Enclose copy of any site documentation that indicates the precise physical location of the proposed Generating Facility (Latitude & Longitude Coordinates and USGS topographic map, or other diagram) and the proposed Point of Interconnection.
   - Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ________________

     ____
   - Is Site Plan Enclosed? Yes ___ No ___
3. Is Site Control Verification Form Enclosed? Yes ___ No ___
4. Equipment Specifications
   Include equipment specification information (product literature) for the solar panels and inverter(s) that provides technical information and certification information for the equipment to be installed with the application.
   - Are Equipment Specifications Enclosed? Yes ___ No ___
5. Protection and Control Schemes
   - Enclose copy of any site documentation that describes and details the operation of the protection and control schemes.
   - Is Available Documentation Enclosed? Yes ___ No ___
   - Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable)..
   - Are Schematic Drawings Enclosed? Yes ___ No ___
6. Register with North Carolina Secretary of State (if not an individual)

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request Application Form is true and correct.

For Interconnection Customer:

Signature ______________________________ Date:________________

(Authorized Agent of the Legal Entity)

Print Name ______________________________

In the Matter of the Application of	**)**	
[Developer Name] for an	**)**	**SITE CONTROL VERIFICATION**
Interconnection Agreement	**)**	
with [Utility Name]	**)**	

I, [Authorized Signatory Name], [Title] of [Developer Name], under penalty of perjury, hereby certify that, [Developer Name] or its affiliate has executed a written contract with the landowner(s) noted below, concerning the property described below. I further certify that our written contract with the landowner(s) specifies the agreed rental rate or purchase price for the property, as applicable, and allows [Developer Name] or its affiliates to construct and operate a renewable energy power generation facility on the property described below.

This verification is provided to [Utility Name] in support of our application for an Interconnection Agreement.

Landowner Name(s): ____

Land Owner Contact information (Phone or e-mail): ____________________________

Parcel or PIN Number: _______________________

County: __________________

Site Address:____

Number of Acres under Contract (state range, if applicable): __________________

Date Contract was executed _________________________

Term of Contract ______________________

______[signature]____________

[Authorized Signatory Name]

[Authorized Signatory Name], being first duly sworn, says that [he/she] has read the foregoing verification, and knows the contents thereof to be true to [his/her] actual knowledge.

Sworn and subscribed to before me this ________ day of _________________, 201____.

________[signature]__________

[Authorized Signatory Name]

[Title], [Developer Name]

__________[Signature of Notary Public]________

Notary Public

____

Name of Notary Public [typewritten or printed]

My Commission expires__________

ATTACHMENT 3

Generating Facility Pre-Application Report Form

Preamble and Instructions
An Interconnection Customer who requests a Pre-Application Report must submit this Pre-Application Report Request by hand delivery, mail, e-mail, or fax to the Utility along with the non-refundable fee of $300.

DISCLAIMER: Be aware that this Pre-Application Report is simply a snapshot in time and is non- binding. System conditions can and do change frequently.

❑ Check here if payment is enclosed. Fee is required for application to be considered complete.

Date:

____

Interconnecting Customer Name (print): ____________________

Contact Person: ____________________

Mailing Address: ____________________

City: ____________________ State: __________ Zip Code: __________

Telephone (Daytime): ____________________

E-Mail Address: ____________________

Alternative Contact Information (e.g., system installation contractor or coordinating company) Name (print): ____________________

Role: ____________________

Contact Person: ____________________

Mailing Address: ____________________

City: ____________________ State: __________ Zip Code: __________

Telephone (Daytime): ____________________

E-Mail Address: ____________________

Facility Information:

1) Proposed Facility Location

Address (or cross-roads): ____________________

City: ____________________ State: __________ Zip Code: __________

❑ Site Map provided (Google, MapQuest, etc.)

- ❑ Grid Coordinates - Latitude: ____________ Longitude: ____________
- ❑ Pole or Tower number if available: ______________________

2) Primary Energy Source

Choose one:

Renewable	**Non-Renewable**
☐ 1. Solar – Photovoltaic	☐ 17. Fossil Fuel - Diesel
☐ 2. Solar – thermal	☐ 18. Fossil Fuel - Natural Gas (not waste)
☐ 3. Biomass – landfill gas	☐ 19. Fossil Fuel - Oil
☐ 4. Biomass – manure digester gas	☐ 20. Fossil Fuel – Coal
☐ 5. Biomass – directed biogas	☐ 21. Fossil Fuel – Other (specify below)
☐ 6. Biomass – solid waste	☐ 22. Other (specify below)
☐ 7. Biomass – sewage digester gas	
☐ 8. Biomass – wood	
☐ 9. Biomass – other (specify below)	
☐ 10. Hydro power – run of river	
☐ 11. Hydro power - storage	
☐ 12. Hydro power – tidal	
☐ 13. Hydro power – wave	
☐ 14. Wind	
☐ 15. Geothermal	
☐ 16. Other (specify below)	

3) Prime Mover

Choose one:

1. ☐ Photovoltaic (PV)	5. ☐ Steam Turbine
2. ☐ Fuel Cell	6. ☐ Micro-turbine
3. ☐ Reciprocating Engine	7. ☐ Other, including Combined Heat and Power (specify below)
4. ☐ Gas Turbine	

4) Type of Generator

Choose one:

1. ☐ Inverter-based Machine 2. ☐ Rotating Machine 3. ☐ Rotating Machine with Inverters	

5) ~~Size~~Nameplate Capacity: ___kW

Maximum Generating Capacity Requested: ______________ kWAC

6) Generator Configuration:

❑ Single-phase ❑ Three Phase

7) Interconnection Configuration

❑ New Generation

❑ Stand-alone

❑ Addition to existing commercial or industrial customer's delivery

Customer's Electric Utility account number: ____________________

Customer's Electric meter number: __________________________

Is Customer's kW load going to increase or decrease?

❑ No

❑ Yes, Details ___________________________________

Proposed Point of Interconnection on Customer-side of Utility meter

____

OR

❑ Addition to existing generation

❑ Stand-alone

❑ Addition to existing commercial or industrial customer's delivery

Customer's Electric Utility account number: ____________________

Customer's Electric meter number: __________________________

Is Customer's kW load going to increase or decrease?

❑ No

❑ Yes, Details ___________________________________

Type of Existing Generation: ______________________________

Size of Existing Generation: ____________ kW_{AC}

Proposed Point of Interconnection on Customer-side of Utility meter

____

Additional Comments

____

____

____

____

Certification Codes and Standards

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

NEMA MG 1-1998, Motors and Small Resources, Revision 3

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

NFPA 70 (2002), National Electrical Code

UL 1741, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

Certification of Generator Equipment Packages

1.0 Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in Attachment 4 of the North Carolina Interconnection Procedures, (2) it has been labeled and is publicly listed by such NRTL at the time of the Interconnection Request, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the Parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the Interconnection Customer's side of the point of common coupling shall be required to meet the requirements of the North Carolina Interconnection Procedures.

6.0 An equipment package does not include equipment provided by the Utility.

Attachment 6

Interconnection Request Application Form for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW

This Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the Interconnection Request may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Interconnection Request Application Form.

If the Interconnection Request is submitted solely due to a transfer of ownership of the Generating Facility, the fee is $50.

Interconnection Customer

Name: ______________________________

Contact Person: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: __________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Contact (if different than Interconnection Customer)

Name: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: __________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Owner(s) of the Generating Facility: ______________________________

Generating Facility Information

Facility Location (if different from above):

Address: ______________________________

City: ______________ State: ________ Zip: ____________

County: ______________________________

Utility: ______________________________

Account Number: ______________________________

Inverter Manufacturer: ______________ Model: ______________

Nameplate Rating (each inverter): ______________ kW (AC) (each inverter)

______________ kVA (AC) (each inverter)

______________ Volts (AC) (each inverter)

Single Phase: ________ Three Phase: ________

System Design Capacity[2]: ______________ kW (AC) (system total)

______________ kVA (AC) (system total)

For photovoltaic sources only:

Total panel capacity: ______________ kW (DC) (system total)

Maximum ~~Physical Export Capability~~Generating Capacity Requested:[3]

(calculated)[4] kW (AC)

For other sources:

Maximum ~~Physical Export Capability~~Generating Capacity Requested:[2]

____________ kW (AC)

Prime Mover: Photovoltaic ☐ Reciprocating Engine☐

---

[2] Total inverter capacity.

[3] At the Point of Interconnection, this is the maximum possible export power that could flow back to the utility. Unless special circumstances apply, load should not be subtracted from the System Design Capacity.

[4] For a photovoltaic installation, the utility will calculate this value as the lesser of (1) the total kW inverter capacity and (2) the total kW panel capacity (no DC to AC losses included, for simplicity).

Fuel Cell☐ Turbine ☐ Other ☐

ENERGY SOURCE TABLE

Renewable	Non-Renewable
H-1. Solar – Photovoltaic H-2. Solar – thermal H-3. Biomass – landfill gas H-4. Biomass – manure digester gas H-5. Biomass – directed biogas H-6. Biomass – solid waste H-7. Biomass – sewage digester gas H-8. Biomass – wood H-9. Biomass – other (specify below) H-10. Hydro power – run of river H-11. Hydro power - storage H-12. Hydro power – tidal H-13. Hydro power – wave H-14. Wind H-15. Geothermal H-16. Other (specify below)	H-17. Fossil Fuel - Diesel H-18. Fossil Fuel - Natural Gas (not waste) H-19. Fossil Fuel - Oil H-20. Fossil Fuel – Coal H-21. Fossil Fuel – Other (specify below) H-22. Other (specify below)

Energy Source: _______________ (choose from list above)

Is the equipment UL 1741 Listed? Yes ____ No ____

If Yes, attach manufacturer's cut-sheet showing UL 1741 listing

Estimated Installation Date: ________ Estimated In-Service Date: ________

The 20 kW Inverter Process is available only for inverter-based Generating Facilities no larger than 20 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the North Carolina Interconnection Procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1. ______	______	______
2. ______	______	______
3. ______	______	______
4. ______	______	______
5. ______	______	______

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Interconnection Request Application Form is true. I agree to abide by the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return the Certificate of Completion when the Generating Facility has been installed.

Signed: ______________________________

Title: ______________________ Date: __________

Contingent Approval to Interconnect the Generating Facility (For Utility use only)

Interconnection of the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return of the Certificate of Completion.

Utility Signature: ______________________________

Title: ______________________ Date: __________

Interconnection Request ID number: ______________________

Utility waives inspection/witness test? Yes ____No _____

Certificate of Completion
for Interconnecting a Certified Inverter-Based
Generating Facility No Larger than 20 kW

Is the Generating Facility owner-installed? Yes _____No _____

Interconnection Customer

Name:______________________________

Contact Person: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ___________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Location of the Generating Facility (if different from above)

Address: ______________________________

City: ______________ State: ________ Zip: ___________

Electrician

Name:______________________________

Company: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ___________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

License Number: ______________

Date Approval to Install Generating Facility granted by the Utility: ___________

Interconnection Request ID Number: ______________________

Inspection:

The Generating Facility has been installed and inspected in compliance with the local building/electrical code of ______________________

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Signature: ______________________

Print Name: ______________________ Date: ______________

As a condition of interconnection, you are required to send/ email/ fax a copy of this form along with a copy of the signed electrical permit to (insert Utility information below):

Utility Name: ______________________

Attention: ______________________

E-Mail Address: ______________________

Address: ______________________

City: ______________ State: ________ Zip: __________

Fax: ______________

Approval to Energize the Generating Facility (For Utility use only)

Energizing the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW.

Utility Signature: ______________________

Title: ______________________ Date: ______________

Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW

1.0 Construction of the Facility

The Interconnection Customer (Customer) may proceed to construct (including operational testing not to exceed two hours) the Generating Facility when the Utility approves the Interconnection Request and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may interconnect the Generating Facility with the Utility's System and operate in parallel with the Utility's System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Utility, and

2.3 The Utility has either:

2.3.1 Completed its inspection of the Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Utility, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. Within ten (10) Business Days of the inspection, ~~T~~the Utility shall provide a written statement that the Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Utility does not schedule an inspection of the Generating Facility within ten Business Days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Utility waives the right to inspect the Generating Facility.

2.4 The Utility has the right to disconnect the Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable American National Standards Institute (ANSI) standards and all applicable regulatory requirements.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

The Customer shall not operate the Generating Facility is such a way that the Generating Facility would exceed the Maximum Generating Capacity Requested.

4.0 Access

The Utility shall have access to the disconnect switch (if a disconnect switch is required) and metering equipment of the Generating Facility at all times. The Utility shall provide reasonable notice to the Customer, when possible, prior to using its right of access.

5.0 Disconnection

The Utility may temporarily disconnect the Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Generating Facility does not operate in a manner consistent with these Terms and Conditions.

5.4 The Utility shall inform the Customer in advance of any scheduled disconnection, or as soon as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

All insurance policies must be maintained with insurers authorized to do business in North Carolina. The Parties agree to the following insurance requirements:

7.1 If the Customer is a residential customer of the Utility, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

7.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

7.3 The Customer may provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices.

8.0 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

9.0 Termination

The agreement to interconnect and operate in parallel may be terminated under the following conditions:

9.1 By the Customer

By providing written notice to the Utility and physically and permanently disconnecting the Generating Facility.

9.2 By the Utility

If the Generating Facility fails to operate for any consecutive 12-month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 Permanent Disconnection

In the event this Agreement is terminated, the Utility shall have the right to disconnect its facilities or direct the Customer to disconnect its Generating Facility.

9.4 Survival Rights

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility

10.1 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new owner.

10.2 The new owner must complete and submit a new Interconnection Request agreeing to abide by these Terms and Conditions for interconnection and parallel operations within 20 Business Days of the transfer of ownership. The Utility shall acknowledge receipt and return a signed copy of the Interconnection Request Application Form within ten Business Days.

10.3 The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request Application Form indicates that a Material Modification has occurred or is proposed.

System Impact Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this ____ day of __________ 20___ by and between ____, a __________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____, a ______________ existing under the laws of the State of ______________________________________, ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, Dated ________________and received by the Utility on ___________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Interconnection Customer has requested the Utility to perform a system impact study to assess the impact of interconnecting the Generating Facility with the Utility's System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a system impact study consistent with the North Carolina Interconnection Procedures.

3. The scope of the system impact study shall be subject to the assumptions set forth in Appendix A to this Agreement.

4. A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study.

5. In performing the study, the Utility shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6. The System Impact Study Report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Generating Facility as proposed:

   6.1. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection, considering the Nameplate Capacity of the Generating Facility;

   6.2. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection, considering the Maximum Generating Capacity Requested;

   6.3. Initial review of grounding requirements and electric system protection

7. The System Impact Study shall model the impact of the Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Generating Facility is being installed.

8. The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9. A System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary.

10. The System Impact Study will also include an analysis of distribution and transmission impacts as may be necessary to understand the impact of the proposed Generation Facility on electric system operation.

11. A System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service.

12. The System Impact Study will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection

13. The System Impact Study will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

14. A system impact study shall provide the information outlined in Section 1.3.2 of the Interconnection Procedures.

15. A distribution System Impact Study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

16. Affected Systems may participate in the preparation of a System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a System Impact Study that covers potential adverse system impacts on their electric systems, and the Utility has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

17. The Utility shall have an additional 15 Business Days from the time set forth in Section 19.0 the System Impact Study Agreement to complete the dual scenario System Impact Study reports for a Project B.

18. If the Utility uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the System Impact Study shall consider all generating facilities (and with respect to paragraph 18.3 below, any identified Upgrades associated with such interconnection with a lower Queue Number) that, on the date the system impact study is commenced –

18.1. Are directly interconnected with the Utility's electric system; or

18.2. Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

18.3. Have a pending Interconnection Request to interconnect with the Utility's electric system with a lower Queue Number.

19. The System Impact Study shall be completed within a total of 65 Business Days if transmission system impacts are studied, and 50 Business Days if distribution system impacts are studied, but in any case, shall not take longer than a total of 65 Business Days unless the study involves Affected Systems per Section 16.0 or the studied Interconnection Request is a Project B per Section 17.0. The period of time for the Utility to complete the System Impact Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

20. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Facilities deposit made by the Interconnection Customer at the time of the Interconnection Request. After the study is completed, the Utility shall deliver a summary of professional time.

21. The Interconnection Customer must pay any study costs that exceed the Interconnection Request Deposit without interest within 20 Business Days of receipt of the invoice. If the deposit exceeds the invoiced fees or the Interconnection Customer's costs exceed the aggregate deposits received and the Interconnection Customer withdraws the Interconnection Request, the amount of funds equal to the difference will be settled in accordance with Section 6.3 of the NC interconnection Standard.

22. <u>Governing Law, Regulatory Authority, and Rules</u>

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

23. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

24. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

25. Waiver

25.1. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

25.2. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

26. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

27. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

28. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

29. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

29.1. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

29.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

30. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Utility]	**[Insert name of Interconnection Customer]**
______________________	______________________
Signed ______________________	Signed ______________________
Name (Printed):	Name (Printed):
______________________	______________________
Title ______________________	

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the Interconnection Request, subject to any modifications in accordance with the Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Utility.

Facilities Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this _________ day of ________________ 20____ by and between ________________________________, a ______________________________ organized and existing under the laws of the State of ______________________________, ("Interconnection Customer,") and, ____, a _________________ existing under the laws of the State of __________, ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity in addition to an existing Generating Facility consistent with the Interconnection Request Application Form completed by the Interconnection Customer, dated ____________________ and received by the Utility on ___________________; and the single-line drawing provided by the Interconnection Customer, dated __________________ and received by the Utility on ___________________ and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Utility has completed a System Impact Study and provided the results of said study to the Interconnection Customer (this recital to be omitted if the Parties have agreed to forego the system impact study); and

WHEREAS, the Interconnection Customer has requested the Utility to perform a Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study and/or any other relevant studies in accordance with Good Utility Practice to physically and electrically connect the Generating Facility with the Utility's System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a facilities study consistent with the North Carolina Interconnection Procedures.

3. The scope of the facilities study shall be subject to data provided in Appendix A to this Agreement.

4. The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact studies. The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Utility's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the construction time required to complete the installation of such facilities.

   If the study is for a Project B, the study shall assume the interdependent Project A is interconnected.

5. The Utility may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Generating Facility if it is willing to pay the costs of those facilities

6. A deposit of the good faith estimated facilities study cost is required from the Interconnection Customer. If the unexpended portion of the Interconnection Request deposit made for the Interconnection Request exceeds the estimated cost of the facilities study, no payment will be required of the Interconnection Customer.

7. In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the Utility's receipt of this Agreement, or completion of the Facilities Study for an Interdependent Project A whichever is later. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days. The period of time for the Utility to complete the Facilities Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

8. Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer.

9. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Request deposit made by the Interconnection Customer at the time of the Interconnection Request. After the study is completed the Utility shall deliver a summary of professional time.

10. The Interconnection Customer must pay any study costs that exceed the Interconnection Request deposit without interest within 20 Business Days of receipt of the invoice. If the unexpended portion of the Interconnection Request deposit exceeds the invoiced fees and the Interconnection Customer withdraws the Interconnection Request, the Utility shall make

refund to the Customer pursuant to Section 6.3 of the North Carolina Interconnection Procedures.

11. Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

13. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

14. Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

15. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

16. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

17. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

19. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

For the Interconnection Customer

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, circuits, etc.

On the one-line diagram, indicate the ~~generation capacity~~Maximum Generating Capacity Requested attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Utility station. Number of generation connections: ________________

____

Will an alternate source of auxiliary power be available during CT/PT maintenance?

Yes __________ No __________

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes __________ No __________

(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, distribution line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Utility's System. .

Tower number observed in the field (Painted on tower leg)*:

Number of third party easements required for lines*:

* To be completed in coordination with Utility.

Is the Generating Facility located in Utility's service area?

Yes __________ No __________ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction Date: ____________________

Generator step-up transformers receive back feed power Date: ____________________

Generation Testing Date: ____________________

Commercial Operation Date: ____________________

Attachment 9

NORTH CAROLINA

[FINAL / INTERIM] INTERCONNECTION AGREEMENT

For State-Jurisdictional Generator Interconnections

Effective May 15, 2015

Docket No. E-100, Sub 101

Between

Utility Name

And

Customer Name

"Project Name"

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This Interconnection Agreement ("Agreement") is made and entered into this _____ day of __________, 20__, by ____ ("Utility"), and ____ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Utility Information

Utility: ____

Attention: ____

Address: ____

City: ______________________, State: ________ Zip: ______

Phone: ________________ Fax: ________________________

Interconnection Customer Information

Name: ____

Project Name: ____

Attention: ____

E911 Address: ____

City: ______________________ State: ________ Zip: ______

Phone: ________________ Fax: ________________________

County: __________________________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Applicability

This Agreement shall be used for all Interconnection Requests submitted under the North Carolina Interconnection Procedures except for those submitted under the 20 kW Inverter Process in Section 2 of the Interconnection Procedures.

1.2 Purpose

If an Interim Interconnection Agreement, this Agreement documents the Utility's ability to interconnect the Generating Facility and provides the Preliminary Estimated Interconnection Facilities Charge and the Preliminary Estimated System Upgrade Charge that was developed in the System Impact Study. Milestones have not been established and the Utility offers no estimate on when the required facilities might be installed.

If a Final Interconnection Agreement, this Agreement governs the terms and conditions under which the Interconnection Customer's Generating Facility will interconnect with, and operate in parallel with, the Utility's System.

1.3 No Agreement to Purchase or Deliver Power or RECs

This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power or Renewable Energy Certificates (RECs). The purchase or delivery of power, RECs that might result from the operation of the Generating Facility, and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Utility.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement between the Utility and the Interconnection Customer.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Utility shall construct, operate, and maintain its System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriters' Laboratories, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the System or equipment of the Utility and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Appendices to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Utility and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Utility's System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Appendices to this Agreement.

1.5.6 The Utility shall coordinate with all Affected Systems to support the interconnection.

<u>1.5.7 The Customer shall not operate the Generating Facility is such a way that the Generating Facility would exceed the Maximum Generating Capacity Requested.</u>

1.6 Parallel Operation Obligations

Once the Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Generating Facility in the applicable control area, including, but not limited to: 1) any rules and procedures concerning the operation of generation set forth in Commission-approved tariffs or by the applicable system operator(s) for the Utility's System and; 2) the Operating Requirements set forth in Appendix 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Utility's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Appendices 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 ~~The~~ If the Generating Facility is interconnected to the Utility's Distribution System, the Interconnection Customer shall design its Generating Facility to (1) have reactive power capability as required by IEEE 1547, ~~maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging,~~ unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis, and (2) maintain a composite power delivery at the Point of Interconnection at approximately unity power factor, unless the Utility has specific requirements for the Generating Facility to utilize the required reactive power capability. ~~The requirements of this paragraph shall not apply to wind generators.~~

1.8.2 If the Generating Facility is interconnected to the Utility's Transmission System, the Interconnection Customer shall design its Generating Facility to have the capability to operate at 0.95 leading to 0.95 lagging at the Maximum Generating Capacity Requested at the Point of Interconnection, unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis.

1.8.~~2~~3 The Utility is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Generating Facility when the Utility requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 1.8.1 or outside the range established by the Utility that applies to all similarly situated generators in the control area. In addition, if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.~~3~~4 Payments shall be in accordance with the Utility's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of any prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.9 Capitalized Terms

Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 of the North Carolina Interconnection Procedures or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Utility of such activities no fewer than ten (10) Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day, unless otherwise agreed to by the Parties. The Utility may, at its own expense, send qualified personnel to the Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Utility a written test report when such testing and inspection is completed.

2.1.2 The Utility shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Utility of the safety, durability, suitability, or reliability of the Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Utility shall use Reasonable Efforts to list applicable parallel operation requirements in Appendix 5 of this Agreement. Additionally, the Utility shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Utility shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Generating Facility in parallel with the Utility's System without prior written authorization of the Utility. The Utility will provide such authorization once the Utility receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Utility may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Utility at least five (5) Business Days prior to conducting any on-site verification testing of the Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Utility shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this Article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Utility 20 Business Days written notice and physically and permanently disconnecting the Generating Facility from the Utility's System.

3.3.2 The Utility may terminate this agreement for failure to comply with the requirements of Article 7.1.2 or Article 7.1.3.

3.3.3 Either Party may terminate this Agreement after Default pursuant to Article 7.6.

3.3.4 Upon termination of this Agreement, the Generating Facility will be disconnected from the Utility's System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.5 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination, including any remaining term requirements for payment of Charges that are billed under a monthly payment option as prescribed in Article 6.

3.3.6 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Utility's System, the Utility's Interconnection Facilities or the systems of others to which the Utility's System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or the Interconnection Customer's Interconnection Facilities.

Under Emergency Conditions, the Utility may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Utility's System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Utility may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Utility's System when necessary for routine maintenance, construction, and repairs on the Utility's System. The Utility shall provide the Interconnection Customer with five (5) Business Day notice prior to such interruption. The Utility shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Utility may suspend interconnection service to effect immediate repairs on the Utility's System. The Utility shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Utility shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generating Facility could cause damage to the Utility's System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Utility may disconnect the Generating Facility. The Utility shall provide the Interconnection Customer with five (5) Business Day notice of such disconnection, unless the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Generating Facility

The Interconnection Customer must receive written authorization from the Utility before making a Material Modification or any other change to the Generating Facility that may have a material impact on the safety or reliability of the Utility's System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Utility's System to their normal operating state as soon as reasonably practicable following a temporary or emergency disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Appendix 2 of this Agreement. The Utility shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Utility.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Utility's Interconnection Facilities.

4.2 Distribution Upgrades

The Utility shall design, procure, construct, install, and own the Distribution Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, on-going operations, maintenance, repair, and replacement, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this Article 5 shall apply unless the interconnection of the Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Utility shall design, procure, construct, install, and own the Network Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Utility elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, on-going operations, maintenance, repair, and replacement shall be borne by the Interconnection Customer.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Interconnection Customer shall pay 100% of required Interconnection Facilities and any other charges as required in Appendix 2 pursuant to the milestones specified in Appendix 4.

The Interconnection Customer shall pay 100% of required Upgrades and any other charges as required in Appendix 6 pursuant to the milestones specified in Appendix 4.

Upon receipt of 100% of the foregoing pre-payment charges, the payment is not refundable due to cancellation of the Interconnection Request for any reason.

6.1.2 If implemented by the Utility or requested by the Interconnection Customer in writing within 15 Business Days of the Interconnection Facilities Delivery Date, the Utility shall provide the Interconnection Customer a final accounting report within 120 Business Days addressing any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Utility for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within 20 Business Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within 20 Business Days of the final accounting report. If necessary and appropriate as a result of the final accounting, the Utility may also adjust the monthly charges set forth in Appendix 2 of the Interconnection Agreement.

6.1.3 The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades, as set forth in Appendix 6 of this Agreement. The Utility shall bill the Interconnection Customer for the costs of providing the Utility's Interconnection Facilities including the costs for on-going operations, maintenance, repair and replacement of the Utility's Interconnection Facilities under a Utility rate schedule, tariff, rider or service regulation providing for extra facilities or additional facilities charges, as set forth in Appendix 2 of this Agreement, such monthly charges to continue throughout the entire life of the interconnection.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Appendix 4 of this Agreement. A Party's obligations under this provision may be extended by agreement, except for timing for Payment or Financial Security-related requirements set forth in the milestones, which shall adhere to Section 5.2.4 of the Standards. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Appendix 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) the delay will materially affect the schedule of another Interconnection Customer with subordinate Queue Position, (3) attainment of the same milestone has previously been delayed, or (4) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

Pursuant to the Interconnection Agreement Milestones Appendix 4, the Interconnection Customer shall provide the Utility a letter of credit or other financial security arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility's Interconnection Facilities and shall be reduced on a dollar-for-dollar basis for payments made to the Utility under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Utility, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Utility and must specify a reasonable expiration date.

6.3.3 The Utility may waive the security requirements if its credit policies show that the financial risks involved are de minimus, or if the Utility's policies allow the acceptance of an alternative showing of credit-worthiness from the Interconnection Customer.

Article 7. Assignment,Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

7.1.1 The Interconnection Customer shall notify the Utility of the pending sale of an existing Generation Facility in writing. The Interconnection Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generation Facility to a new legal entity, or a change of control of the existing legal entity.

7.1.2 The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generation Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing

7.1.3 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new legal entity owner. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the transfer of ownership or the Utility's Interconnection Facilities shall be removed or disabled and the Generating Facility disconnected from the Utility's System. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.4 This Agreement shall survive a change of control of the Generating Facility' legal entity owner, where only the contact information in the Interconnection Agreement must be modified. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the change of control and provide the new contact information. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.5 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Utility, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will promptly notify the Utility of any such assignment. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof.

7.1.6 Any attempted assignment that violates this article is void and ineffective.

7.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this Article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a

Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money or provision of Financial Security) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 7.6.2, the defaulting Party shall have five (5) Business Days from receipt of the Default notice within which to cure such Default.

7.6.2 If a Default is not cured as provided in this Article, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

8.1.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

8.1.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

8.1.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

8.1.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

8.2 The Utility agrees to maintain general liability insurance or self-insurance consistent with the Utility's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.2.3 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

9.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this Article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written notice of dispute. Such notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within 20 Business Days after receipt of the notice, either Party may contact the Public Staff for assistance in informally resolving the dispute. If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the Commission.

10.4 Each Party agrees to conduct all negotiations in good faith.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with North Carolina and federal policy and revenue requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Utility's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under Article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2.1 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Appendices, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

12.11.2 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.3 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement (Notice) shall be deemed properly given if delivered in person, delivered by recognized national courier service, sent by first class mail, postage prepaid, or sent electronically to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ______________________

Attention: ______________________

Address: ______________________

City: ______________ State: ________ Zip: ______

E-Mail Address: ______________________

Phone: ______________ Fax: ______________

If to the Utility:

Utility: ______________________

Attention: ______________________

Address: ______________________

City: ______________ State: ________ Zip: ______

E-Mail Address: ______________________

Phone: ______________ Fax: ______________

13.2 Billing and Payment
Billings and payments shall be sent to the addresses set out below: If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

E-Mail Address: ______________________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

E-Mail Address: ______________________________

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ________________ State: ________ Zip: ______

Phone: ________________ Fax: ________________

E-Mail Address: ______________________________

Utility's Operating Representative:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ________________ State: ________ Zip: ______

Phone: ________________ Fax: ________________

E-Mail Address: ______________________________

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Utility

Name:____

Print Name: ____________________________________

Title: ____

Date: __________________

For the Interconnection Customer

Name:____

Print Name: ____________________________________

Title: ____

Date: __________________

Glossary of Terms

See Glossary of Terms, Attachment 1 to the North Carolina Interconnection Procedures.

Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, or the Utility. The Utility will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

This agreement will incorporate by reference the one-line diagram submitted by the Customer on ______________________, dated ___________________, with file name "__/____________________________" as part of the Interconnection Request, or as subsequently updated and provided to the Company.

Milestones

Requested Upgrade In-Service Date: ____________

Requested Interconnection Facilities In-Service Date __________

For an Interim Interconnection Agreement, this Appendix 4 is null and void.

Critical milestones and responsibility as agreed to by the Parties:

The build-out schedule does not include contingencies for deployment of Utility personnel to assist in outage restoration efforts on the Utility's system or the systems of other utilities with whom the Utility has a mutual assistance agreement. Consequently, the Requested In-service date may be delayed to the extent outage restoration work interrupts the design, procurement and construction of the requested facilities.

	Milestone	Completion Date	Responsible Party
1)			
2)			
3)			
4)			
5)			
6)			
7)			
8)			
9)			
10)	Expand as needed		

Signatures on next page

Agreed to for the Utility

Name: ______________________________

Print Name: ______________________________

Date: ______________________________

Agreed to for the Interconnection Customer

Name: ______________________________

Print Name: ______________________________

Date: ______________________________

Additional Operating Requirements for the Utility's System and Affected Systems Needed to Support the Interconnection Customer's Needs

The Utility shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Utility's System.

Utility's Description of its Upgrades and Best Estimate of Upgrade Costs

The Utility shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Utility shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

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IREC's Proposed Public Distribution System Interconnection Queue, Updated Monthly

Each utility shall maintain a public interconnection queue, available in a sortable spreadsheet format on its web site, which it shall update on at least a monthly basis. The date of the most recent update shall be clearly indicated.

The public queue should include, at a minimum, the following information about each interconnection application.

1. Application or queue number
2. Facility capacity (kW)
3. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
4. Secondary fuel type (if applicable)
5. Exporting or Non-Exporting
6. City
7. Zip code
8. Substation
9. Feeder name and size
10. Capacity of the transformer to which the project will interconnect
11. Status (active, withdrawn, interconnected, etc.)
12. Date application deemed complete and date utility issued the facility the queue number
13. Date of notification of Fast Track screen results (separately identify 20 kW Inverter Process projects) (if applicable)
14. Fast Track Screen Results (pass or fail, and if fail, identify the screens failed) (separately identify 20 kW Inverter Process projects)
15. Date of notification of Supplemental Review results (if applicable)
16. Supplemental Review Results (pass or fail, and if fail, identify the screens failed)
17. Date of notification of Impact Study results (if applicable)
18. Date of notification of Facilities Study results and/or construction estimates (if applicable)
19. Date final interconnection agreement is provided to customer
20. Date agreement is signed by both parties
21. Date Interconnection Facilities (along with any required Upgrades) are completed and available for operation by the Interconnection Customer
22. Date of grant of permission to operate
23. Final interconnection cost paid to utility

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IREC's Proposed Information to be Included in Quarterly Reports

The following list contains minimum reporting requirements that utilities shall file with the Commission and post publicly on the utility website on a quarterly/bi-annual/annual basis. These reports are intended to provide a high-level analysis of the public queue data described above, plus provide additional detail about the operation of the pre-application process.

Reports should include, at a minimum, the following information:

1. Compiled public queue through the end of that year or reporting period, including all of the information listed above, plus total installed cost without incentives for each project (may be redacted in any publicly available versions)
2. Pre-Application Reports
    a. Total number of reports requested
    b. Total number of reports in process
    c. Total number of reports issued
    d. Total number of requests withdrawn
    e. Maximum, mean, and median processing times from receipt of request to issuance of report.
    f. Number of reports processed in more than 20 Business Days
3. Interconnection Applications:
    a. Total number received, broken down by:
        i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
        ii. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)
    b. 20 kW Inverter Process
        i. Total number of applications processed
        ii. Maximum, mean and median processing times from receipt of complete Application to issuance of Interconnection Agreement
    c. Fast Track Process
        i. Total number of applications that passed
        ii. Total number of applications that failed
        iii. Maximum, mean and median processing times from receipt of complete Application to issuance of Interconnection Agreement
    d. Supplemental Review
        i. Total number of applications that passed
        ii. Total number of applications that failed

iii. Maximum, mean and median processing times from receipt of complete Application to issuance of Interconnection Agreement

e. Study Process

i. System Impact Studies

1., Total number of System Impact Studies completed

2. Maximum, mean, and median processing times from receipt of signed System Impact Study agreement to provision of study results.

ii. Facilities Studies

1. Total number of Facilities Studies completed

2. Maximum, mean, and median processing times from receipt of signed Facility Study agreement to provision of study results.

iii. Maximum, mean, and median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement

f. Construction: Number of projects where final construction milestone was not reached by time specified in the Interconnection Agreement.

g. Number of Projects that achieved Commercial Operation, by:

i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)

ii. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)

4. For each deadline included in the Interconnection Procedures, the Utility shall report:

a. The total number of total deadline events for the reporting period

b. The total number of late completions of deadline events for the reporting period

c. The number of Business or Calendar Days beyond the deadline for each late deadline event in the reporting period

d. The current total number of pending responses that are past the applicable deadline as of the date of the report

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Exhibit SBA-Direct-5

IREC's Proposed Information to be Included in Hosting-Capacity Map

The lines and substations could be color-coded to show areas with available capacity (green), those approaching limits (yellow), and those at or exceeding capacity limits (red). The maps should be easily accessible via utility websites, though a simple log-in process can be used for security purposes. These maps should evolve overtime to include additional information and ultimately actual hosting capacity modeling, but for the first iteration we suggest the following items be included:

Substation:

- Name
- Voltage
- Installed and Queued DG (MW) (aggregated)
- Total DG (MW) (aggregated)
- Projected Load
- Current Penetration level (%)
- Max remaining generation capacity
- Currently scheduled upgrades?
- Notes: (Space to include any other relevant information that can be manually recorded to help guide interconnection applicants, including electrical restrictions, known constraints, etc.)

Feeder:

- Name of substation line connects to
- Line voltage
- Number of phases
- Total capacity
- Currently connected capacity
- Currently queued capacity
- Projected Load
- Current penetration level (%)
- Currently scheduled upgrades?
- Notes: (Space to include any other relevant information that can be manually recorded to help guide interconnection applicants, including electrical restrictions, known constraints (i.e. voltage issues), etc.)

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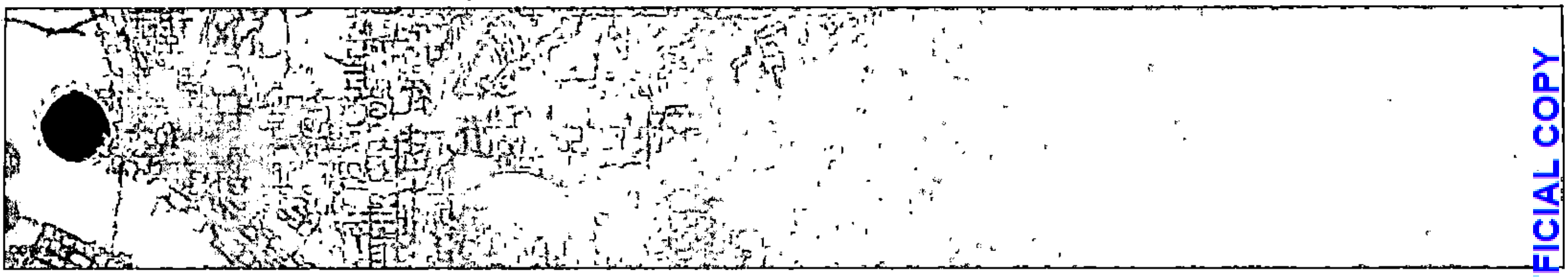
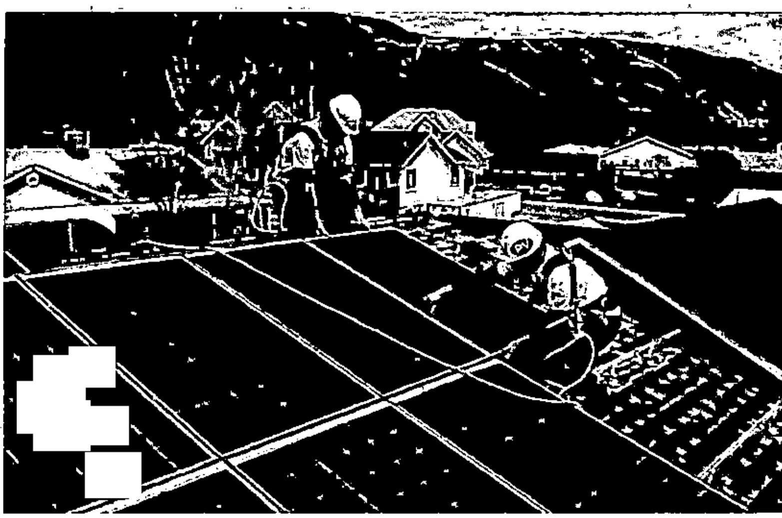
Exhibit SBA-Direct-6

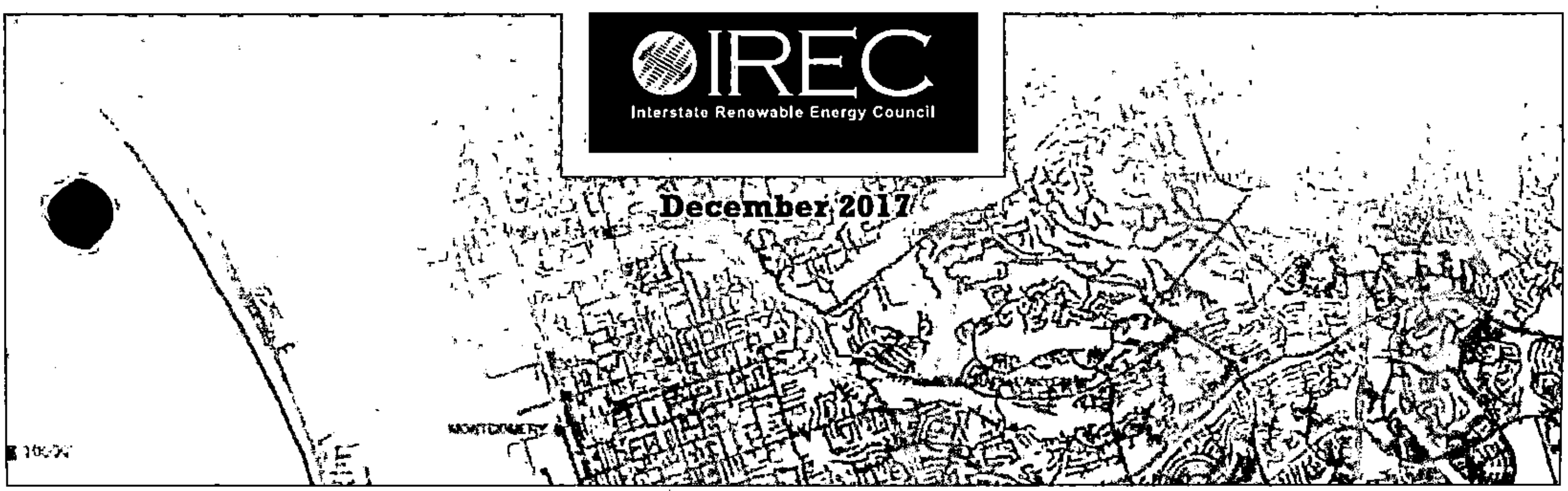


OPTIMIZING THE GRID

A REGULATOR'S GUIDE TO

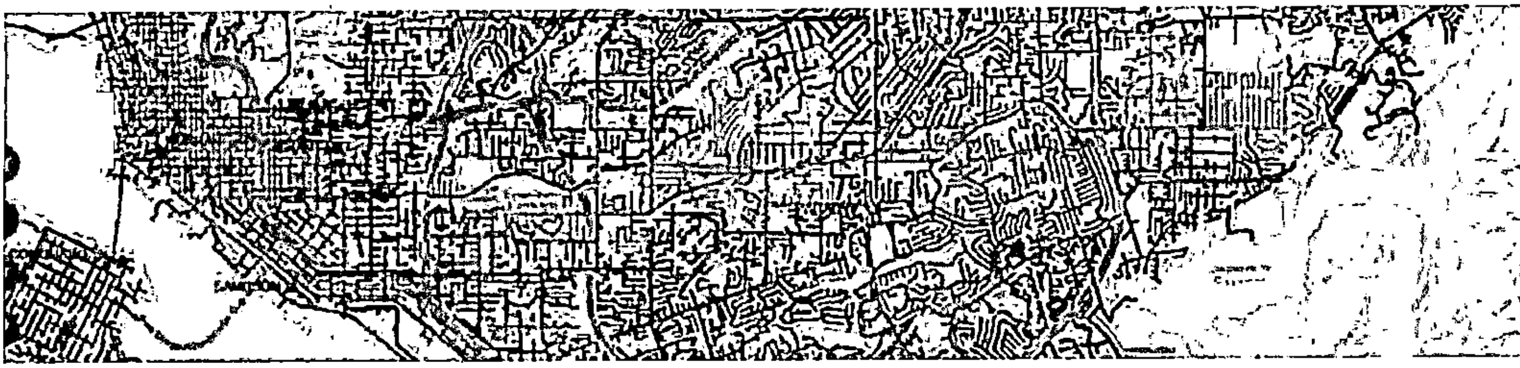
Hosting Capacity Analyses for Distributed Energy Resources





IREC
Interstate Renewable Energy Council

December 2017



OPTIMIZING THE GRID

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Hosting Capacity Analyses for Distributed Energy Resources

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This guide and IREC publications can be found on our website: www.irecusa.org
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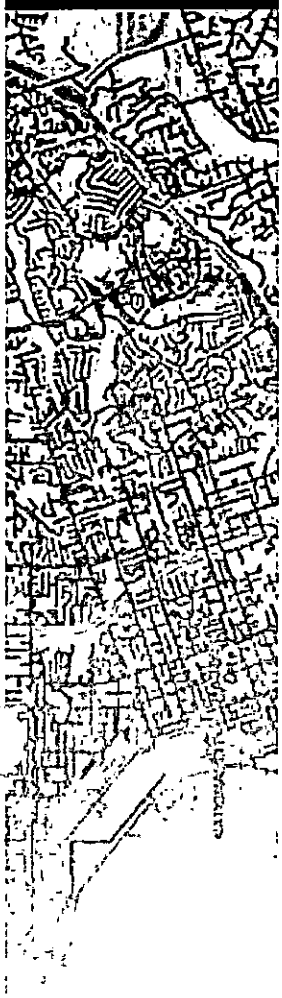
Acronyms and Abbreviations

API	Application Program Interface
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DG	Distributed Generation
DOE	United States Department of Energy
DRP	Distribution Resources Plan (California)
DSIP	Distribution System Implementation Plan (New York)
EPRI	Electric Power Research Institute
GIS	Geographic Information Systems
HCA	Hosting Capacity Analysis
ICA	Integration Capacity Analysis (California)
IDP	Integrated Distribution Planning
IOU	Investor Owned Utility
IREC	Interstate Renewable Energy Council, Inc.
LNBA	Locational Net Benefits Analysis (California)
MW	Megawatt
MN PUC	Minnesota Public Utility Commission
NREL	National Renewable Energy Laboratory
NY PSC	New York Public Service Commission
PG&E	Pacific Gas & Electric
PV	Solar Photovoltaic
REV	Reforming the Energy Vision (New York)
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company
SDSIP	Supplemental Distribution System Implementation Plan (New York)
VDER	Value of Distributed Energy Resources (New York)



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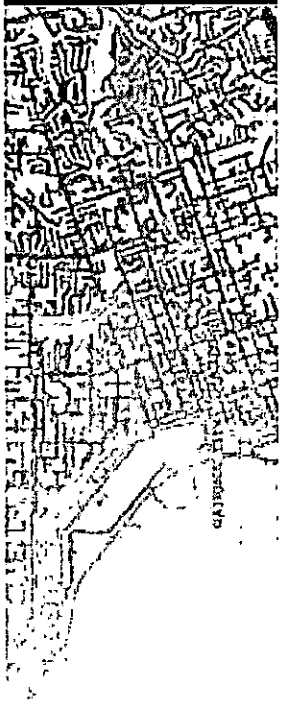

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Executive Summary

Hosting Capacity Analyses (HCAs) allow utilities, regulators and electric customers to make more efficient and cost-effective choices about deploying distributed energy resources on the grid.

From coast to coast, states are experiencing unprecedented growth in distributed energy resources (DERs) – resources located on the electric distribution system, such as renewable energy, energy efficiency and energy storage. With much of this activity being driven by consumers, changes to the nation's outdated electric system are underway. To ensure that the benefits of these DERs are fully optimized, there is a need to proactively integrate them into grid planning, operations and long-term investment decisions. Rather than simply "tolerating" DERs, there is an opportunity to utilize a new tool known as Hosting Capacity Analysis (HCA), which can help more Americans enjoy the benefits and full potential of these resources on the grid.

The term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

HCAs allow utilities, regulators and electric customers to make more efficient and cost-effective choices about deploying DERs on the grid. If adopted with intention, HCA may also function as a bridge to span information gaps between developers, customers and utilities, thus enabling more productive grid interactions and more economical grid solutions.

Utility regulators play a key role in ensuring HCAs are deployed strategically, prudently and for the benefit of all energy customers. *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources* will assist state regulators in guiding and overseeing utilities as they conduct hosting capacity analyses on their distribution circuits, as part of a broader grid modernization or distribution planning efforts and/or in support of their state's near- and long-term energy policy goals.

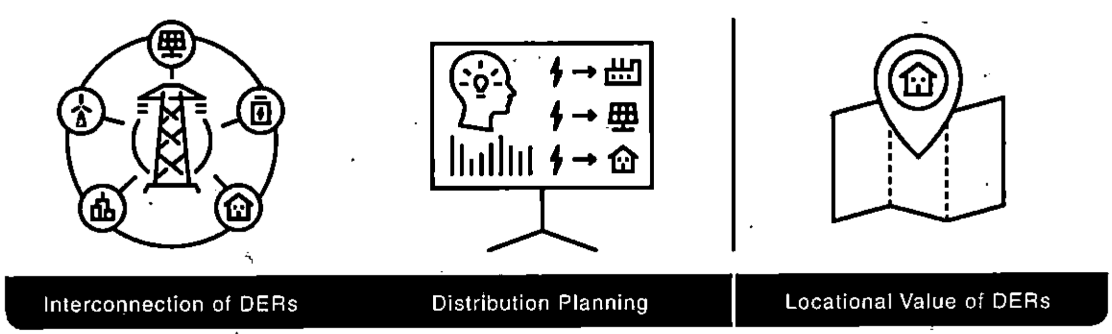
Based on lessons from the handful of states and utilities that have begun to prepare HCAs, this guide focuses on the *process* that will help regulators realize HCAs' full promise in their respective states. The experiences and key takeaways from the states and utilities undertaking these analyses, including California, New York, Minnesota, Hawaii and Pepco Holdings, Inc., provide important insights for other states and utilities to take into consideration as they pursue similar efforts. Details on each can be found in *Appendix A* of the full guide.

Hosting Capacity Analysis Use Cases

There are two principal applications, or use cases, for an HCA: 1) assist with and support the streamlined interconnection of DERs on the distribution grid; and 2) enable more robust distribution system planning efforts that ensure DERs are incorporated and reflected in future grid plans and investments. A third, complementary function of an HCA could be to inform pricing mechanisms for DERs based on separate analyses to assess the benefits of DERs based on their physical location on the grid and their performance characteristics (see Figure ES-1). To achieve an effective HCA, regulators and utilities should carefully consider and articulate their goals and use cases at the outset of an HCA effort.

Use cases can be selected to reflect the unique characteristics and identified goals of states and utilities. These use cases should inform and guide the development of an HCA methodology and its implementation. A process should also be in place to refine the selected use cases as new regulatory, social, and technological conditions emerge. The two major HCA use cases—interconnection and planning—as well as the complementary function of optimizing the locational benefits of DERs are discussed in detail in Section III of the full guide.

Figure ES-1. Hosting Capacity Use Cases



Hosting Capacity Analysis Methodologies

A well-considered methodology for determining hosting capacity is necessary given the variety of factors that affect the grid's ability to host a wide range of DERs. IREC has identified three principle categories of methodologies that are currently being tested and employed by utilities to analyze hosting capacity, generally known as the stochastic, iterative, and streamlined methods. This paper describes these methodologies, including the tradeoffs between them that may make them more or less suited to the various use cases that regulators may select. Briefly, the three methodologies are characterized as follows:

The streamlined method applies a set of simplified algorithms for each power system limitation (typically: thermal, safety/reliability, power quality/voltage, and protection) to approximate the DER capacity limit at nodes across the distribution circuit.

The iterative method directly models DERs on the distribution grid to identify hosting capacity limitations. A power flow simulation is run iteratively at each node on the distribution system until a violation of one of the four power system limitations is identified. The iterative method is also sometimes referred to as the detailed method.

The stochastic method starts with a model of the existing distribution system, then new solar PV (or other DERs) of varying sizes are added to a feeder at randomly selected locations and the feeder is evaluated for any adverse effects that arise from this random allocation. This essentially results in a hosting capacity range.

Different methodologies can result in different hosting capacity values due to different technical assumptions built into the models, and the methodological choices in an HCA can significantly impact whether the results are sufficiently reliable and informative for grid-related planning and decision-making. Section IV of the full guide outlines several key considerations when evaluating and selecting HCA methodologies.

Use cases can be selected to reflect the unique characteristics and identified goals of states and utilities. These use cases should inform and guide the development of an HCA methodology and its implementation.

Regulatory Process Underpinning Hosting Capacity Analyses

The *process* underpinning HCA efforts is key to ensuring that the HCA tool is deployed to support relevant state policy goals and sufficiently reflects the input from stakeholders, ultimately enhancing the benefits for all ratepayers. Still an emerging grid modernization tool, the benefits and drawbacks of different HCA methodologies are being revealed, and likely will become even more apparent with time. However, rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations. Given the substantial investment in time, energy and resources that HCA efforts require, there is value in taking the time early in the process to ensure that the tool being developed is capable of meeting identified objectives. Questions or concerns about what an HCA can do should be addressed before widespread implementation, lest substantial resources be invested in something that proves invaluable or ambiguously useful. This paper identifies the key process steps and considerations therein, summarized as follows:

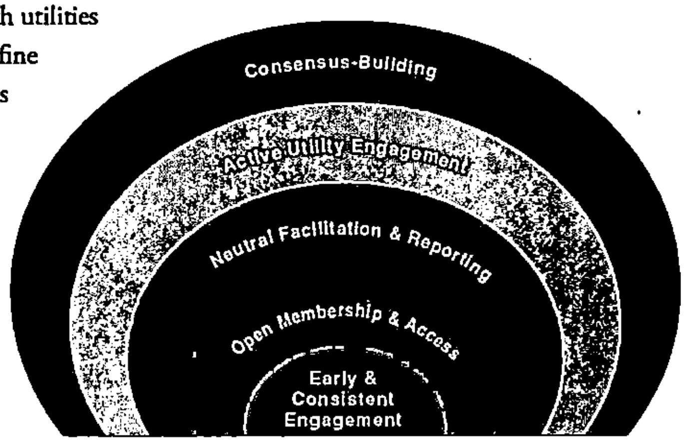


Figure ES-2. Regulatory Stakeholder Engagement Strategies

Establish a stakeholder process to work with utilities and other interested stakeholders to select, refine and implement the HCA. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Regulators should also retain a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals. Figure ES-2 outlines best practices for stakeholder engagement, drawing from lessons learned in states such as California, Minnesota and New York.

Select and define the use cases for the HCA with input from diverse stakeholders, ensuring they are clearly designed to address and achieve identified goals, including state energy policy goals. These use cases should inform and guide the development of an HCA methodology and its implementation. As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases for HCA together at the beginning of the process. Defining use cases ensures that the cart is not put before the horse and will also prevent potentially costly and inefficient undertakings that do not produce useable results.

Identify criteria to guide implementation of the HCA at the outset. Working through the established stakeholder process to identify and answer key questions regarding the scope, duration and other key elements of the HCA can help ensure a more efficient process throughout (and greater buy-in from all involved). The *frequency of updating* the HCA results, the *extent of the grid covered by HCA*, and *criteria for ensuring transparency* in the selected HCA methodology and its results are all important to discuss and define. In addition, regulators may consider whether to create a phased roadmap for implementation of HCA, depending on the level of sophistication of the utilities and the timeline for achieving state energy goals. However, care should be taken not to create an endless implementation timeline that quickly becomes obsolete or fails to miss near term opportunities for deployment and use.

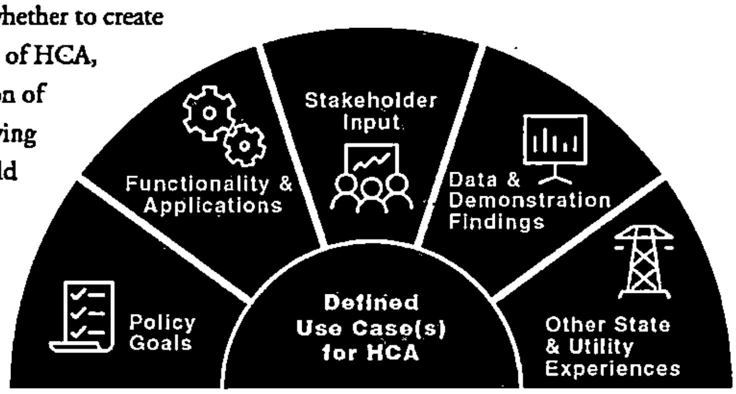


Figure ES-3. Key Elements to Defining Use Case(s) for HCA

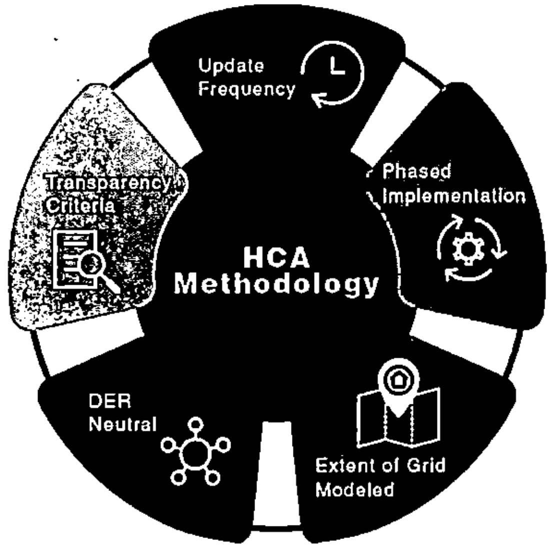


Figure ES-4. Criteria to Guide Implementation of HCA

Develop an HCA methodology (or methodologies) most appropriate to the use cases. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals, such that the final tool is designed appropriately to meet such goals. This can be accomplished by providing clear and specific guidance and ensuring that the methodologies and assumptions are transparent and informative to all involved stakeholders and end-users. Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid and range of DERs can eventually be analyzed. Different methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Given the variety of factors that affect the grid's ability to host a wide range of DERs, it is necessary to select a well-considered methodology for determining hosting capacity based upon its intended use.

Validate the results of the HCA over time. As with any model or analysis, real-world validation can help improve accuracy and functionality over time. Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data, and set milestones over time to evaluate the performance of the HCA, relative to identified goals.

Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals, such that the final tool is designed appropriately to meet such goals.

As regulators oversee the implementation of HCAs, there are other key considerations to keep in mind, noted throughout the guide. For example, requiring consistency in approaches and methodologies among utilities (where there are multiple utility services territories within a state) will help simplify the implementation and oversight process, while also ensuring a more consistent and efficient utilization of this tool among DER project developers and customers. Data sharing is another key factor shaping the evolution of the electricity grid, and the data collected and generated as part of an HCA will help utilities, regulators, and DER customers better capture the diverse value streams of DERs. Concerns surrounding data sharing can and should be managed proactively and should not be a reason to not pursue HCAs or related efforts.

In addition, given swift changes to technologies, performance and markets, HCAs should be agnostic to the type of DER analyzed to ensure that it remains useful over time. Technology agnosticism can also help utilities identify opportunities to expand hosting capacity with other DERs and deploy non-wires alternatives as part of utility grid upgrades and investment plans.

As utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricityservice provided to all ratepayers.

Perhaps most importantly, HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. As consumers and the market responds to new programs, policies and price signals, so too should the HCAs reflect the anticipated and planned changes to DER adoption. More robust DER forecasting methodologies will need to be developed in order to provide greater accuracy of the HCA.

Ultimately, as utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricity service provided to all ratepayers.

With this guide in hand, regulators can provide the leadership and direction needed to ensure the process, function, and implementation of HCA supports and enables the critical grid transformations underway across the country.

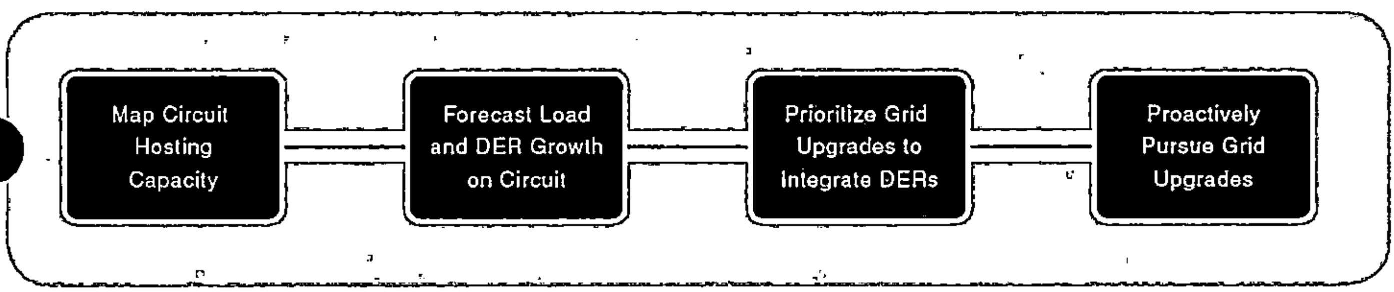
I. Introduction

Hosting capacity analysis, or HCA, has emerged as a key tool for capturing and optimizing the benefits of distributed energy resources (DER)[1] on the grid, while also proactively managing increasing penetrations of DERs and ensuring the reliability of the grid. HCA is used to determine the amount of DERs that the distribution system can accommodate at a given time and a given location. HCA allows utilities, regulators, and DER customers to make more efficient and cost-effective choices about whether to pursue interconnection of a DER technology at a specific grid location by providing data about the amount of new DERs that can be accommodated at a particular node[2] on the grid. Mapping the hosting capacity of the entire distribution grid provides even more powerful benefits: customers can identify optimal locations to install and interconnect DERs; regulators and utilities can develop price signals to direct DERs to locations on the grid where they can provide the greatest benefit; and utilities can better plan for grid infrastructure improvements that expand hosting capacity at locations with high demand for DERs. Ultimately these actions will optimize the deployment of DERs on the system to preserve and improve the quality of service they provide to all ratepayers.

Hosting capacity analysis, or HCA, has emerged as a key tool for capturing and optimizing the benefits of distributed energy resources (DERs).

IREC and Sandia National Laboratories set forth the concept of Integrated Distribution Planning (IDP) as an approach to proactive planning for DER growth at high penetrations. IDP consists of four principal components: (1) mapping a circuit's hosting capacity; (2) forecasting the expected growth of DERs on that circuit; (3) prioritizing grid

Figure 1. Principal Components of Integrated Distribution Planning



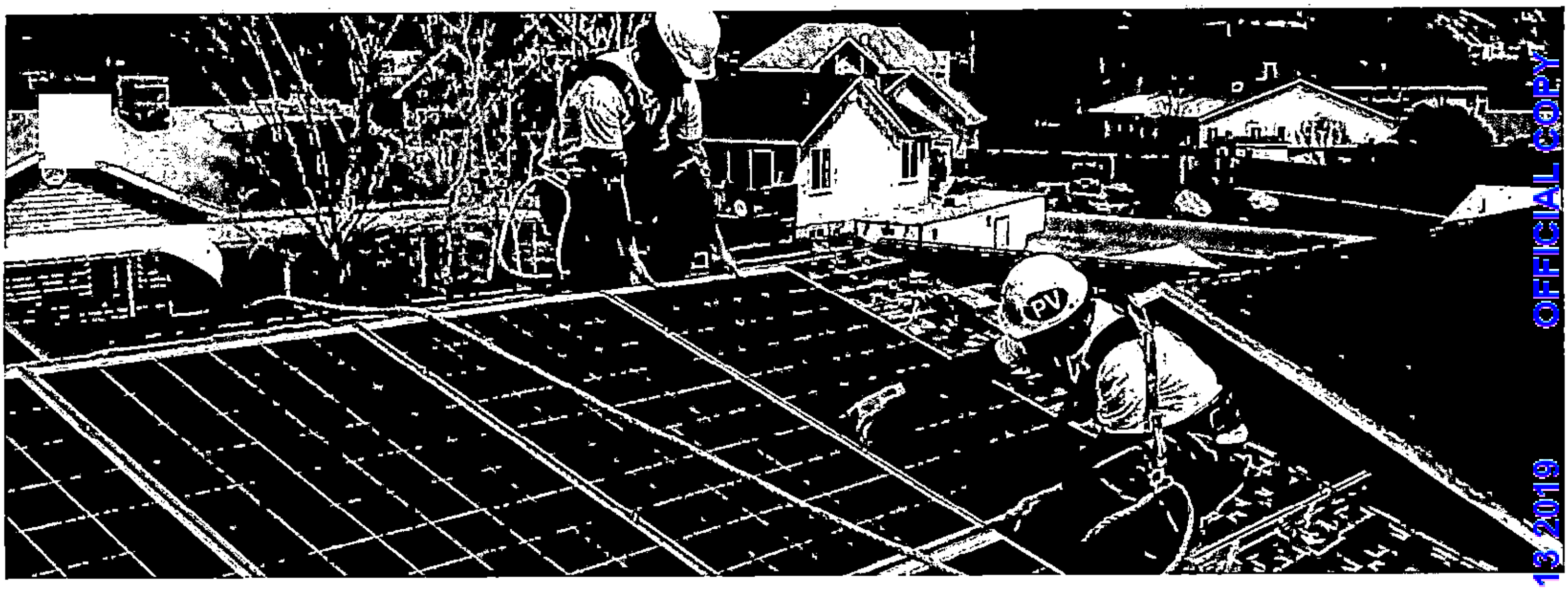
upgrades to integrate DERs; and (4) proactively pursuing grid upgrades (including traditional capital upgrades as well as DERs themselves) to meet anticipated grid needs. By combining HCA with DER forecasting, a utility can better plan for grid upgrades to facilitate and enable the integration of forecasted DER growth in specific areas. Regulators and utilities can also steer DERs to the grid locations where they can provide the greatest system benefits at the least cost. States and utilities around the country are beginning to adopt IDP approaches.[4] The widespread adoption of IDP holds tremendous promise for enabling the modernization of the distribution grid, but the hosting capacity piece of the IDP puzzle remains at a nascent stage.

The intent of this paper is to support regulators as they guide and inform the implementation of a hosting capacity analysis, as part of a broader grid modernization or distribution planning effort and in support of their state's near- and long-term energy policy goals.

The purpose of this paper is to assist state regulators in guiding and overseeing utilities as they prepare hosting capacity analyses on their distribution circuits. Based on lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses, the paper focuses on the process that will help regulators realize the full promise of HCA in their respective states. The experiences and key takeaways from the states undertaking these analyses are fully outlined in the case studies which can be found in Appendix A. Key process steps discussed in this paper include:

- Definition and selection of use cases[5] for HCA tailored to the needs and goals of their states;
- Selection of the hosting capacity methodology best suited to realizing identified use cases; and
- Establishing rules and criteria to implement and improve on that methodology.

A number of resources exist to guide regulators and utilities in exploring the technical aspects of hosting capacity methodologies.[6] Exploring the technical nuances of those methodologies is beyond the scope of this paper, which will instead highlight some of the tradeoffs between methodologies that may make them more or less suited to the various use cases that regulators may select. In sum, the intent of this paper is to support regulators as they guide and inform the implementation of a hosting capacity analysis, as part of a broader grid modernization or distribution planning effort and in support of their state's near- and long-term energy policy goals.



II. Hosting Capacity Fundamentals

A. HOSTING CAPACITY DEFINITION

As used in this paper, the term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria, and without requiring significant infrastructure upgrades.[7] HCA evaluates a variety of circuit operational criteria—typically thermal, power quality/voltage, protection, and safety/reliability[8]—under the presence of a given level of DER penetration and identifies the limiting factor or factors for DER interconnections.[9] The hosting capacity is the greatest amount of a DER with a specific operational profile, such as that of solar photovoltaics (PV) or an energy storage system, that can be accommodated before a violation of one or more of the technical criteria occurs on a line section or feeder.[10] To provide the accuracy needed to guide distribution-level decision-making and/or inform the interconnection process, the HCA needs to be performed at a granular level (typically at every selected node on assessed feeders) across the entire distribution circuit.

HCA reveals snapshots of the amount of different types of DERs that can be hosted at a particular point in time across the grid. These snapshots are not fixed but change constantly as grid conditions change: that is, as new DERs are interconnected, as new controls are added to the circuit, and/or as load curves shift.

The main factors that drive the amount of DER that can be hosted on the grid, without requiring upgrades or modifications to the distribution system are:

(1) precise DER location,

(2) nature of the load curve on the feeder,

(3) the feeder's design and physical and operational characteristics, and

(4) DER technology.[11]

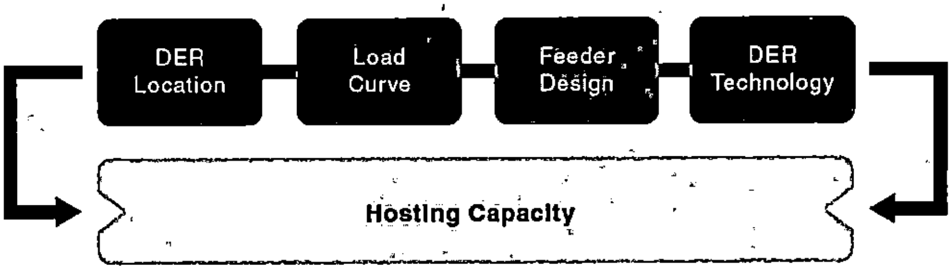


Figure 2. Factors Impacting Hosting Capacity

Distribution Grid Terms

Distribution Circuit—The conductors and devices downstream of the substation feeder breaker and including all laterals, primary and secondary portions.

Feeder—A single distribution line which connects the substation at primary voltage to laterals or secondary circuits.

Line section—A portion of a distribution circuit between two automatic sectionalizing devices or an automatic sectionalizing device and the end of the distribution line. Automatic sectionalizing devices would typically refer to the feeder breaker or line reclosers, but could include other devices.

Node—A node is a point on a feeder between two line sections. Circuit characteristics may be analyzed at each selected node along the circuit.

The hosting capacity of any given feeder is a range of values, which depend on the specific location and type of resource in question.[12] For instance, a feeder may be able to accommodate 2 MW of solar PV at a node close to the substation but only 0.5 MW (500 kW) at a node further from the substation, or a feeder may be able to accommodate more solar PV with advanced inverters than solar PV without advanced inverters.[13] The hosting capacity also varies significantly between DER technologies, feeder characteristics, such as a voltage class, regulating devices, and load profile.

A well-considered methodology for determining hosting capacity is necessary given the variety of factors that can affect the grid's ability to host a wide range of DERs. IREC has identified three principal categories of methodologies that are currently being tested and employed by utilities to analyze hosting capacity, generally known as the stochastic, iterative, and streamlined methods. These methodologies, including the tradeoffs between them, are described in detail below. There is overlap between the methods, as well as iterations of each type. For example, the Electric Power Research Institute (EPRI) recently developed the DRIVE tool, which EPRI characterizes as a version of the streamlined method.[14] Information has not yet been published detailing the differences between EPRI's version of the streamlined methodology and the streamlined methodology tested in California and discussed below.

Importantly, the methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Certain assumptions, such as how many load hours or nodes are evaluated, may also result in more or less precise hosting capacity assessments. The methodological choices in an HCA can significantly impact whether the results are sufficiently reliable and informative for grid-related planning and decision-making. To achieve a rigorous HCA, regulators and utilities should carefully consider and articulate their goals and use cases at the outset of an HCA effort, and then select and tailor the methodology best suited to achieve those objectives.

B. HOSTING CAPACITY USE CASES

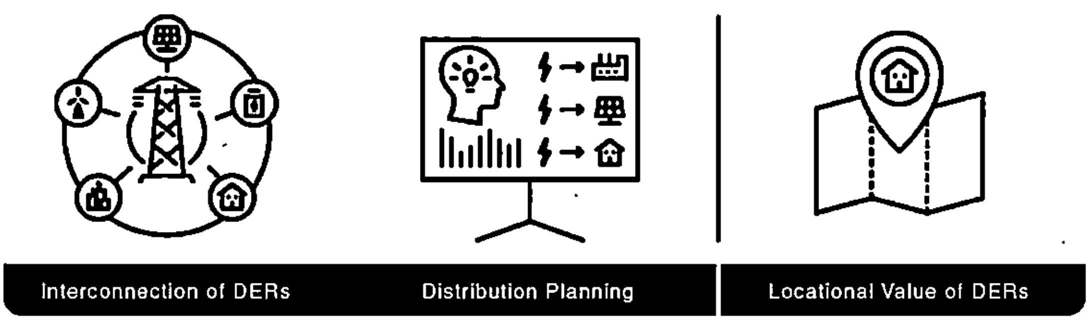
There are two principal applications, or use cases, for an HCA: 1) assist with and support the streamlined interconnection of DERs on the distribution grid; and 2) enable more robust and granular distribution system planning. The third complementary function of an HCA could be to inform pricing mechanisms for DERs based on separate analyses to assess the locational benefits of DERs.

As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases at the beginning of the process. Selecting an HCA methodology before defining the use cases puts the cart before the horse; a methodology may need to be dramatically altered or discarded entirely if it turns out to be ill-suited to meeting the state's or utility's goals.

Use cases can be selected to reflect the unique characteristics and identified goals of the state and utility. These use cases should inform and guide the development of an HCA methodology and its implementation. A process should also be in place to refine the selected use cases as new regulatory, social, and technological conditions emerge. The two major HCA use cases—interconnection and planning—as well as the complementary function of optimizing the locational benefits of DERs are discussed in detail below.

As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases at the beginning of the process. Selecting an HCA methodology before defining the use cases puts the cart before the horse; a methodology may need to be dramatically altered or discarded entirely if it turns out to be ill-suited to meeting the state's or utility's goals. As described in the case studies in Appendix A, the failure to consider the use cases prior to selecting the methodologies has resulted in a potential need to revise the methodologies in California. In addition, stakeholders have voiced concerns about whether the methodologies used in Minnesota and New York will actually be able to achieve those states' goals.

Figure 3. Hosting Capacity Use Cases



Regulators, with input from involved stakeholders, should not only identify desired HCA use cases up front, but they should also do so with specificity. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals so that the final tool is designed appropriately to meet those goals. For example, if more streamlined interconnection processes is the goal, then there should be some early discussions, before the tool is built, around what level of precision in the HCA would be needed to accomplish this objective.

Regulators, with input from involved stakeholders, should not only identify desired HCA use cases up front, but they should also do so with specificity. Regulators will need to provide sufficient guidance for utilities to clarify what HCA should be capable of doing and how it can be used to support identified goals so that the final tool is designed appropriately to meet those goals.

In addition to identifying use cases, regulators may consider identifying specific elements to guide utilities in developing the HCA methodology. Such elements can include:

(1) specification of the desired level of granularity (i.e., performing HCA down to the line section and node level);

(2) specification of the desired level of scalability (i.e., whether HCA should be performed across the entire distribution system at the outset or only on those feeders with the greatest projected DER demand, and whether it should be performed on single-phase feeders in addition to three-phase feeders);

(3) guidance for repeatability as new DERs are interconnected and feeder characteristics change;

(4) transparency in the methods and results;

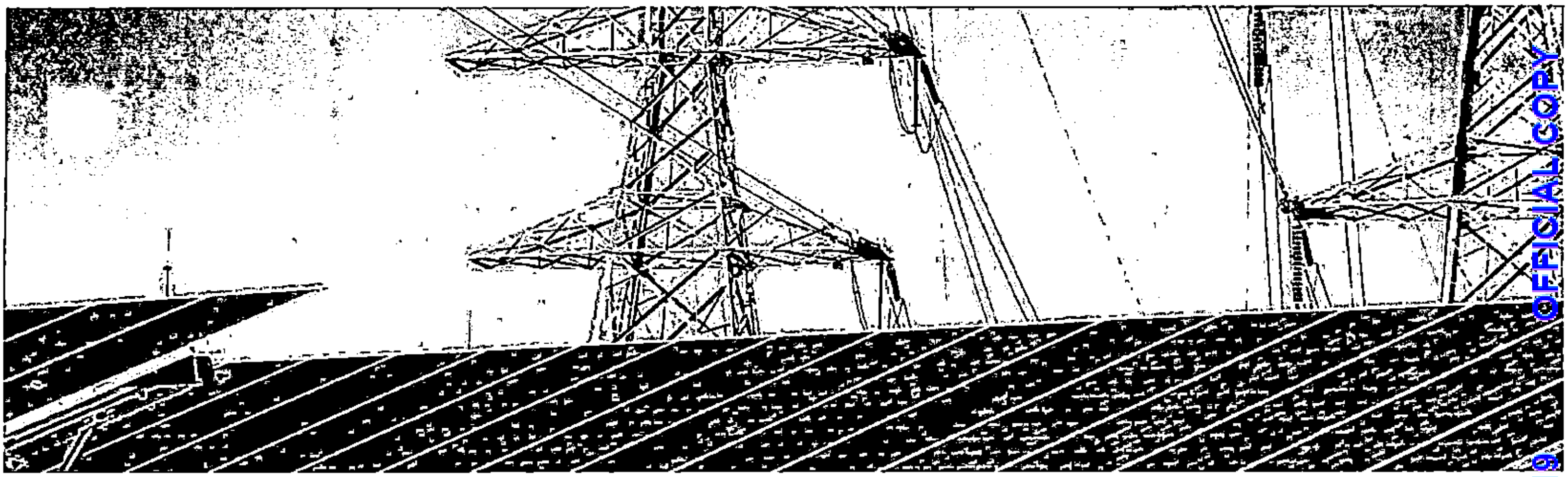
(5) validation of techniques to ensure confidence in the results obtained through the HCA;

(6) readily accessible data for easy use by consumers, developers, and planners;[15]

(7) frequency of publication (i.e., annual, quarterly, real-time, etc.); and

(8) types of DERs to be modeled (i.e., distributed generation, energy storage, electric vehicles, or all DERs).

At the same time, regulators may want to avoid being overly prescriptive in their goals so that utilities have the space to develop a workable tool for their service areas in a timely manner. Conducting an open dialogue about the pros and cons of approaches that have been piloted by states and utilities (including those discussed in the case studies in Appendix A) can help regulators determine how best to strike a balance between prescribing detailed goals and allowing some flexibility for utilities.



III. Selecting the Hosting Capacity Use Cases

The use cases that regulators, stakeholders, and utilities select for HCA will inform the choice of HCA methodology and the guidelines for deploying it, such as the frequency of updating and the portions of the grid to be covered by the initial HCA rollout. The two primary use cases for HCA— interconnection and planning—are described herein. In addition, the following section includes a discussion of how the HCA can be used in a complementary fashion along with efforts to identify locational benefits of DERs to fully optimize DER siting.

A. INTERCONNECTION USE CASE

In many states, interconnection standards and utility interconnection processes are not keeping pace with DER growth and are replete with inefficiencies and time- and resource-intensive protocols that cause backlogs and interconnection gridlock.[16] For example, a 2015 study by NREL found that utilities in five states failed to meet review time requirements for up to 58% of residential and small commercial solar interconnection applications.[17] In states, such as in North Carolina, where there have been significant amounts of larger-scale distributed generation deployed (e.g., projects 1 MW or greater), the utilities have fallen drastically behind on their ability to keep up with the interconnection study process. As an example of this interconnection gridlock in North Carolina, Duke Energy regularly takes more than a year to complete the study process for the interconnection of a 2 to 5 MW solar PV generator on its distribution system.[18]

While a number of factors can contribute to interconnection gridlock, a prominent one is that customers wanting to adopt DERs have traditionally had limited access to information about the conditions on the grid to help them select optimal and appropriate sites and design projects that are responsive to (and not in violation of) the available hosting capacity at their chosen site. Another barrier to streamlined interconnection processes is the time- and bandwidth-limited utility staff who are tasked with processing increasing volumes of DER interconnection requests. Even requests that are not likely to move forward—because they require costly grid upgrades to accommodate them on the system—still require the time and attention of utility staff to review and study the interconnection applications. Providing customers with more information upfront, such as through an HCA and accompanying distribution system map, can help reduce the number of ill-suited projects proposed and result in better designed projects that are within the hosting capacity at that particular site and thus could require fewer utility resources to be spent individually studying their impacts.[19]

1. Streamlining the Interconnection Processes for DERs

HCA can help address the challenges of interconnection gridlock in two important ways. First, HCA can provide reliable data about the hosting capacity of nodes across the circuit for use in streamlining and expediting the review of interconnection applications. When a customer seeks to interconnect at a given node, the utility can check to see if its proposed DER project falls within the hosting capacity value for that location. If it does, the project can be approved to interconnect with little to no additional review or study with assurance that it will not compromise system safety or reliability. Second, if the project falls outside the identified hosting capacity, it can be directed to the study process or the customer can be provided information that allows her to redesign the project to fit within the hosting capacity limits (and/or address known constraints through system or operational redesign). Perhaps most importantly, HCAs based on the actual engineering specifications of the circuit are able to yield *more precise indicators of the amount of DER that can be accommodated than the simplified interconnection screens in place in many states today*,[20] such as the 15 percent of peak load screen commonly used to determine whether a project connecting to the distribution grid will raise islanding concerns or cause backfeed beyond the substation.[21] By providing a more accurate and efficient method of reviewing a project, HCA allows more DERs to connect to the grid more promptly, *without compromising grid safety and reliability*.[22]

Ultimately, with frequent updating of HCA, utilities can move toward automated interconnection processes. Interconnection customers can also use the detailed HCA data to identify potential project alternatives that would help them avoid hosting capacity limits, such as use of on-site storage to shift peak demand or interconnection agreements that allow curtailment during limited peak hours of the year.[23]

2. Maps to Identify Grid Locations for DERs

Mapping the hosting capacity of entire circuits and making these results publicly available can help guide DER customers to locations where they can provide more value to the grid and minimize project costs. User-friendly maps displaying HCA results and downloadable data files will also help customers understand what project sizes and technologies can be most easily accommodated in a particular location, which can help them better predict the cost and timeline of the interconnection process.[24] Giving customers the ability to self-select optimal interconnection sites will in itself speed up the interconnection process by channeling applications to the grid locations where they are most likely to be quickly approved. Early grid mapping efforts and adoption of pre-application reports,[25] in states such as California and Hawaii, have been widely accepted as a useful tool by both DER customers and utilities. They appear to be positively redirecting projects and reducing the number of speculative or non-viable projects that ultimately seek to interconnect.[26]

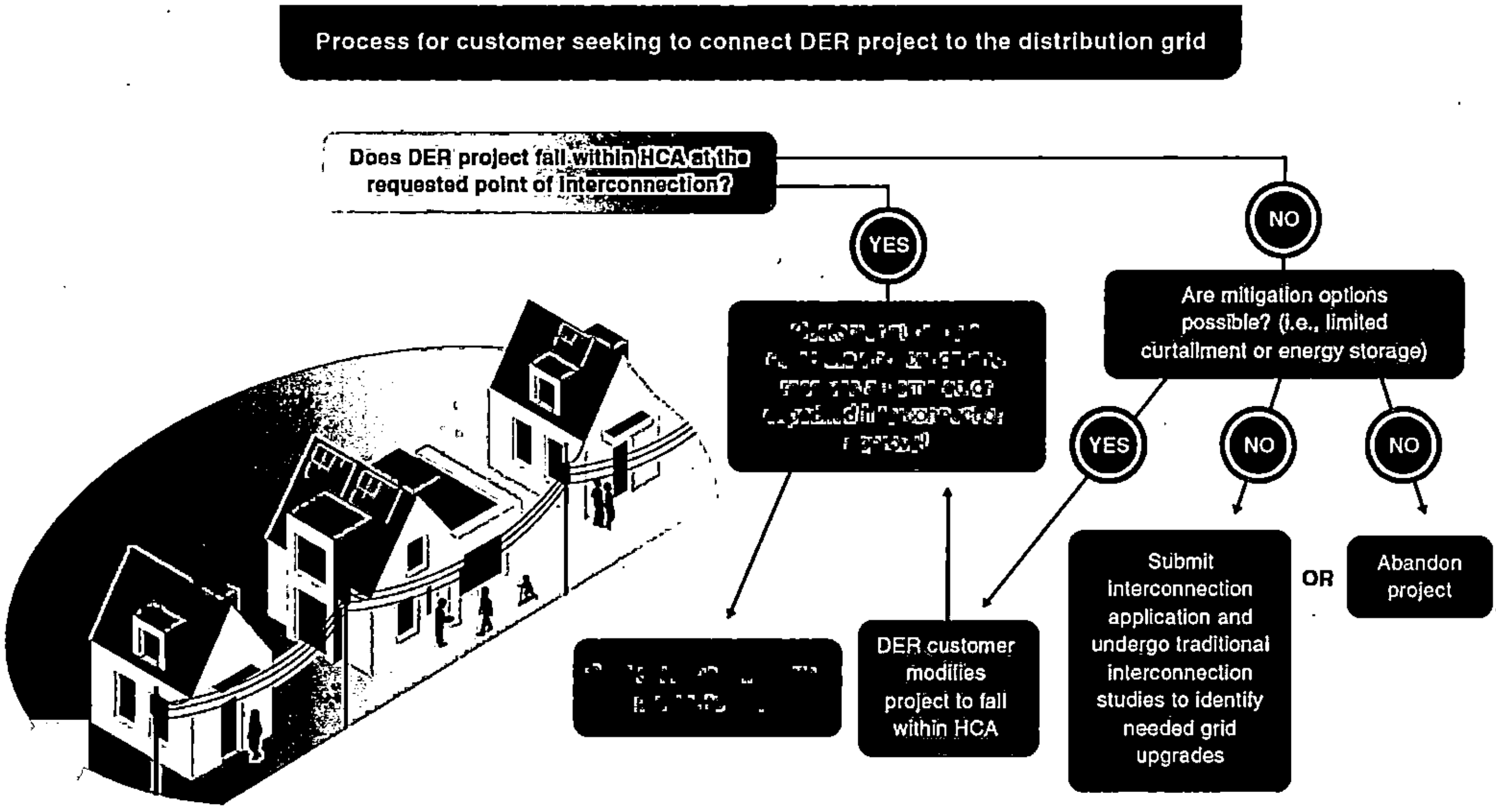


Figure 4. Illustrative Interconnection Use Case for HCA

As discussed below, an HCA map can also be combined with efforts to identify precise locational values to further optimize DER siting.

When interconnection is selected as a use case for HCA, regulators should ensure that the methodology chosen and implemented by utilities yields sufficiently reliable, robust, and granular results and is deployed with sufficient frequency to achieve identified goals and use case functionality. For example, the accuracy of the hosting capacity results is critical to ensuring safe and reliable interconnection while also increasing efficiency and avoiding an overbuilt distribution system. Frequency and accuracy are closely connected and impact the usefulness of the tool for more streamlined interconnection processes. Maps and data files should be updated with new HCA results each time they are generated to ensure that customers have the most current information to make their siting and application decisions.

3. State Experiences with the Interconnection Use Case for HCA

Early experiences in three states demonstrate the value of setting forth interconnection as a use case at the *beginning* of the HCA process (see the case studies in Appendix A for more details regarding individual state experiences).

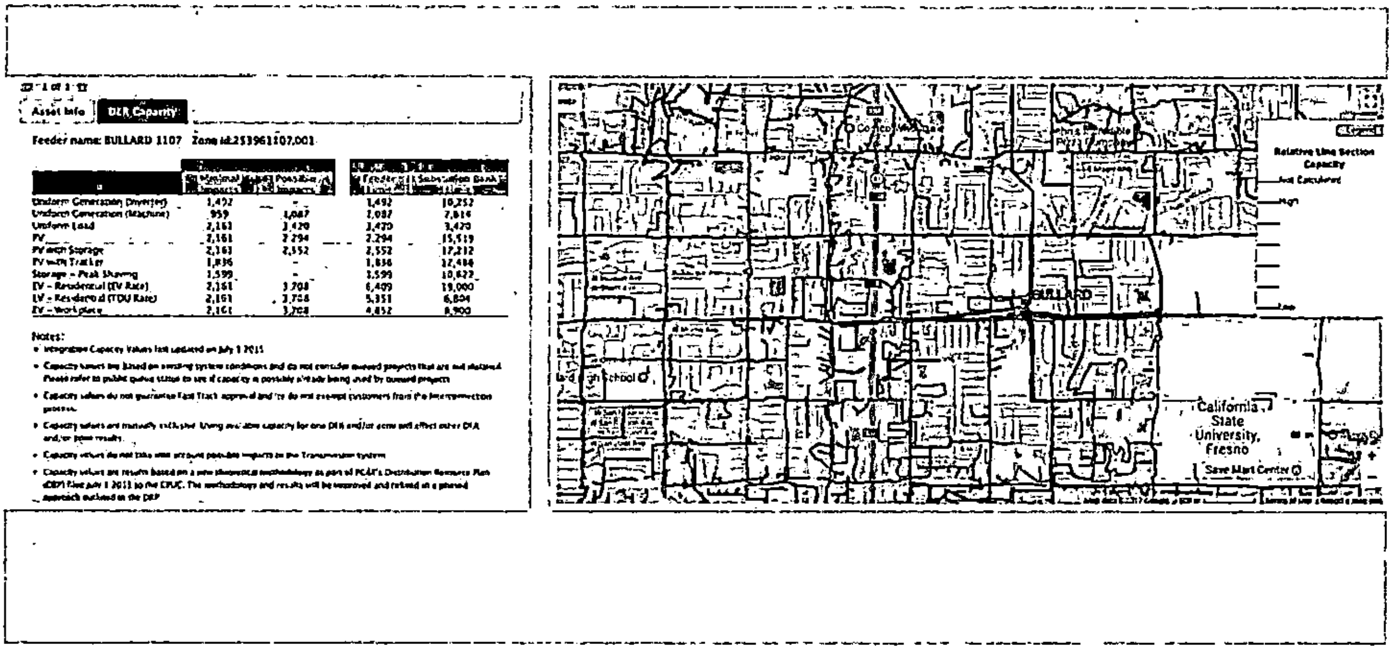


Figure 5. Sample Hosting Capacity Map & Feeder Data
Source: *PG&E, Demonstration A, Integration Capacity Map, available at:*
https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml

In California, the Public Utilities Commission (CPUC) initially ordered the state's major investor owned utilities to prepare an initial integration capacity analysis (synonymous with a hosting capacity analysis) as one part of a Distributed Resources Plan (DRP).[27] The CPUC's guidance ruling specified that one of the goals of the analysis was to "improve the efficiency of the grid interconnection process" and included some specific details in terms of number of circuits, granularity, and modeling methods.[28] After the utilities completed their initial limited deployments, the CPUC took comments and then authorized a more comprehensive demonstration project that would ultimately test out two different methodologies, in consultation with a working group of diverse stakeholders.[29] The lesson learned from this process was that to properly evaluate the methodologies tested, use cases needed to be developed that identified the state's concrete interconnection goals. After identifying those goals more precisely and developing the use cases, the majority of the working group concluded that the streamlined methodology, as tested, was inadequate to meet the goals and that the iterative methodology was better suited to achieve the accuracy and precision required for the interconnection use case.[30] The CPUC ultimately adopted the recommendations of the working group and ordered the utilities to deploy the iterative methodology system-wide for the interconnection use case.[31] The utilities in Hawaii are using a method similar to the iterative method selected in California for use in the interconnection process,[32] and they have identified interconnection as a clear use case for hosting capacity in the state, although the Commission has not yet approved its incorporation into the interconnection procedures.[33]

In New York, by contrast, as part of the Distribution System Implementation Plans (DSIP) docket[34] within the much-larger New York Reforming the Energy Vision (NY REV), the Joint Utilities[35] established the goal of providing HCA maps for customers to use in identifying optimal interconnection grid locations for large-scale solar PV. However, the utilities declined to clearly identify and define interconnection as a use case for the HCA, instead noting only that stakeholders were interested in "exploring the possible implementation of interconnection use cases for hosting capacity."[36] Despite comments from stakeholders urging the New York Public Service Commission (NY PSC) to clearly define use cases and to require examination and transparency regarding whether the selected methodology provides results accurate and reliable enough to meet those use cases, the NY PSC declined to further investigate.[37] The Joint Utilities are thus moving ahead with EPRI's DRIVE Tool (a version of the streamlined method) for their HCAs, but considerable uncertainty remains about whether HCAs developed using this method will help process interconnection requests and shorten timelines, or even whether the current results can accurately guide customers to appropriate interconnection locations. The Joint Utilities' HCAs are also unlikely to be useful in informing scenarios for other DERs, including non-solar distributed generation, smaller-scale solar, distributed energy storage, and/or electric vehicles.

Lastly, the Minnesota Public Utilities Commission (MN PUC) has identified some value to using HCA to inform interconnection as a long-term goal of Xcel Energy's (the state's major investor owned utility) HCA effort, but it has not gone so far as to precisely define the use case.[38] The MN PUC required Xcel Energy to "conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources,"[39] but the initial distribution-system study released by Xcel Energy announced that its HCA results were "not intended to be used for approving interconnection requests," and did not to set forth a process or timeline for producing HCA results that would help to streamline interconnection approvals.[40] After considering stakeholder written and oral comments, the MN PUC required Xcel to file hosting capacity reports with sufficient detail to provide customers "with a starting point for interconnection applications."[41] The MN PUC also directed Xcel to provide information requested by staff and parties on the accuracy of its HCA results, including by conducting a comparison of results in its 2016 report with actual hosting capacity determined through interconnection studies.[42] This information was provided in a subsequent filing[43] and the MN PUC and parties are evaluating the results of the accuracy assessment and what it means for next steps.

As these state experiences illustrate, commencing a hosting capacity process without clear uses and goals creates a real risk of duplicative expenditures by utilities, which are ultimately borne by ratepayers. For instance, if a state selects an HCA methodology not suited to interconnection processing and invests in optimizing that method, utilities will not only expend substantial resources processing individual interconnection applications in the interim, but they may ultimately expend far more resources switching in the future to an HCA method capable of streamlining the interconnection process if that is ultimately desired. To avoid these pitfalls, IREC recommends that regulators learn from the comparative analysis done in California and involve utilities and stakeholders in early discussions about whether interconnection is an appropriate use case for the HCA. If it is adopted, regulators should require utilities to develop and implement an HCA methodology appropriate to that use case.

As these state experiences illustrate, commencing a hosting capacity process without clear uses and goals creates a real risk of duplicative expenditures by utilities, which are ultimately borne by ratepayers.

B. PLANNING USE CASE

Planning is the other primary use case for HCA. Although distribution planning is often framed as an important goal for HCA, no regulator or utility has specified exactly how HCA will be used in the distribution planning process. Failing to specifically define the planning use case can impede regulators' ability to ensure that the HCA methodology developed and deployed will ultimately serve the planning goals. While fewer details are available about the planning use case, based on a lack of concrete examples to draw from, there are emerging grid planning reforms that states are adopting as part of broader grid modernization efforts, which provide useful guidance to regulators considering how to best approach the planning use case for HCAs.

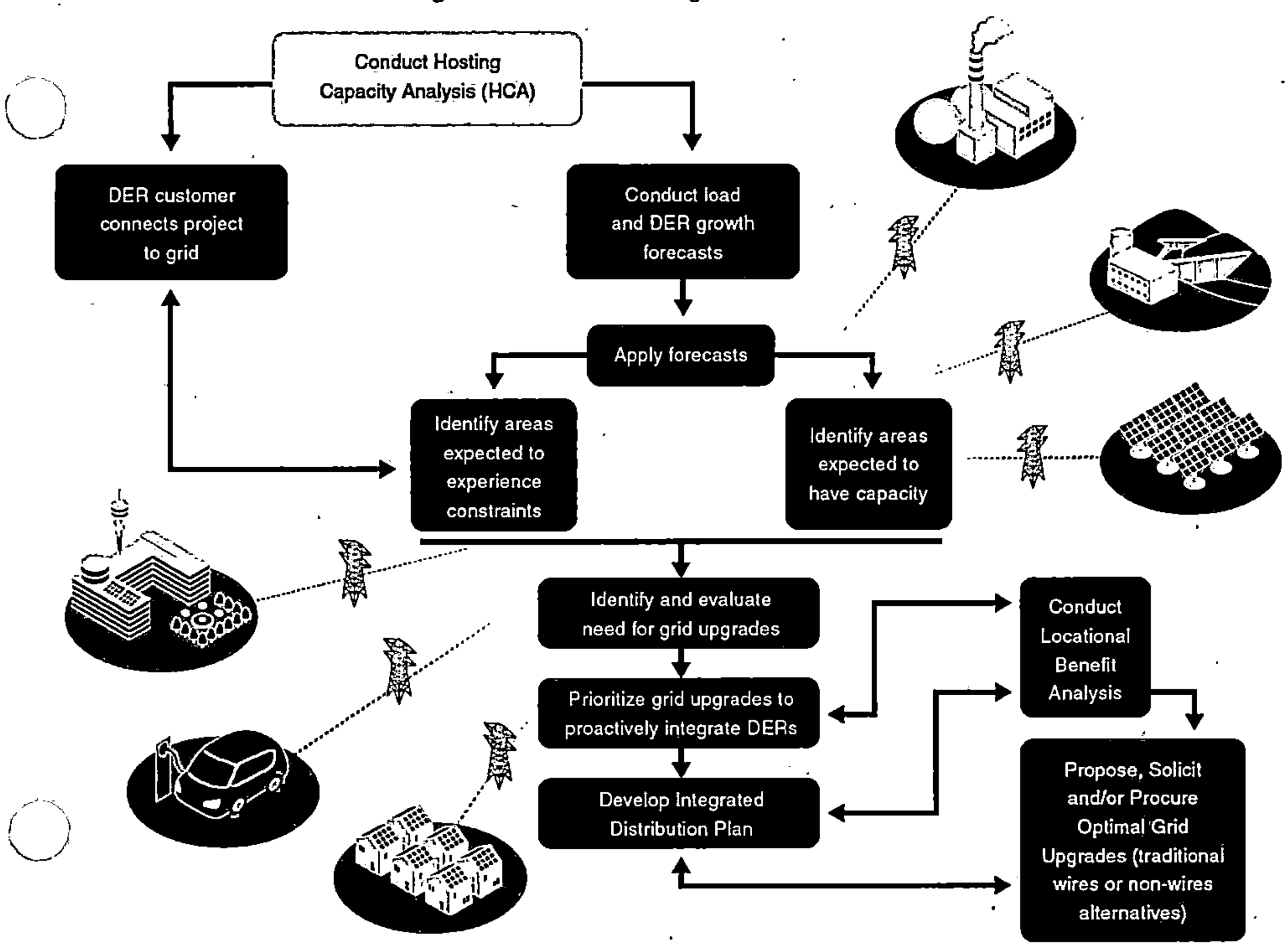
1. Shifting to Proactive, Integrated Distribution Planning

Traditionally, distribution system planning has remained within the exclusive purview of the utilities, and there has been minimal transparency or public involvement in the planning process.[44] In addition, utility-owned assets are normally the preferred solutions to meet identified distribution needs.[45] However, this traditional model for distribution system planning is continuing to evolve with, among other changes, increasing penetration of distributed generation, increased deployment of demand-response technologies, growing customer investments in energy storage and energy management technologies, and policy directives to utilities to build cleaner, more reliable, and more efficient electricity systems. In response to these new conditions, planning the grid for the future warrants new approaches that take into account the growth, benefits and impacts of DERs on the grid, including revised load forecasting and the ability of DERs to offer "non-wires" solutions to distribution grid needs. Both vertically integrated and deregulated states are beginning to recognize that the role of the distribution system is fundamentally changing and the planning process must evolve accordingly.[46] In response, regulators are requiring increasing transparency in the distribution planning process, including by requiring utilities to publicly file distribution resource plans and to increase access to grid data.[47]

The Integrated Distribution Planning process consists of four basic components: (1) mapping the hosting capacity of the system; (2) forecasting DER growth and load growth, (2) identifying and prioritizing grid upgrade needs by comparing growth to available circuit hosting capacities, (3) proactively pursuing grid solutions, including non-wires alternatives, to meet identified needs and integrate and optimize DERs on the grid.[48]

As depicted in Figure 6, an HCA is a central component of more proactive, integrated distribution system planning. Among other functions, an HCA can facilitate utility efforts

Figure 6. Illustrative Planning Use Case for HCA



to integrate DERs under high penetration scenarios, to meet renewable or distributed energy mandates, and to procure and/or deploy DERs as cost-effective, non-wires alternatives to traditional grid investments.[49]

As an alternative to the current reactive process to making distribution system upgrades (wherein the customer with the DER project that triggers the need for a grid upgrade is expected to bear the entire upgrade cost), an HCA can help utilities (and regulators) more proactively identify in advance strategic locations where cost-effective infrastructure investments can increase hosting capacity,[50] thereby benefiting a number of DER customers and other ratepayers. This proactive planning approach permits more efficient and economic allocation of system upgrades, while also optimizing benefits across sources of generation and load and across any number of distribution feeders. It can also speed up the process of interconnecting DERs since steps to expand hosting capacity will have been taken, where appropriate, prior to applications being submitted. By planning for and performing proactive upgrades, utilities can also consider ways to spread upgrade costs more evenly between parties that benefit from them (thus avoiding the scenario where a single customer gets left holding the bag for costly grid upgrades, which ultimately improve hosting capacity for other customers that come after them), including both customers with new generation and load on the distribution system. Lastly, they can procure third-party solutions, including DERs, to meet projected grid needs in lieu of, or in addition to, traditionally procured infrastructure investments.[51]

Clearly defining IDP as a goal of the HCA use case can help ensure that the analysis is fully supportive of this more proactive approach to grid planning. In addition, to ensure that planning goals are realized, it may be necessary to make further improvements to the interconnection processes to facilitate DER integration and capture "the value of DER linked to planning results and opportunities to realize net benefits for all customers through the use of DER provided services."[52]

By articulating with precision the goals of the HCA planning use case, regulators can ensure that an effective HCA tool is developed. For instance, where IDP is part of the planning use case, the HCA may need to be run on the entire distribution system under different scenarios about assumed DER growth overlying varying time horizons.[53] The HCA results would enable the utility to determine when and where the distribution grid is projected to reach its hosting capacity such that solutions can be deployed or procured *before* that location is closed to new DER projects. Regulators should consider how frequently the HCA needs to be run and the level of precision in the HCA results necessary to meet the planning use case goals.

2. Using HCA to Model and Plan for Changes in Customer Behavior

An HCA, as part of the planning use case, can also be used as a tool to help understand how other policy choices may impact how DERs are deployed and how the hosting capacity of the distribution system would change as a result. For example, if a utility is exploring the impact of time-of-use rates for electric vehicle owners, the HCA can be

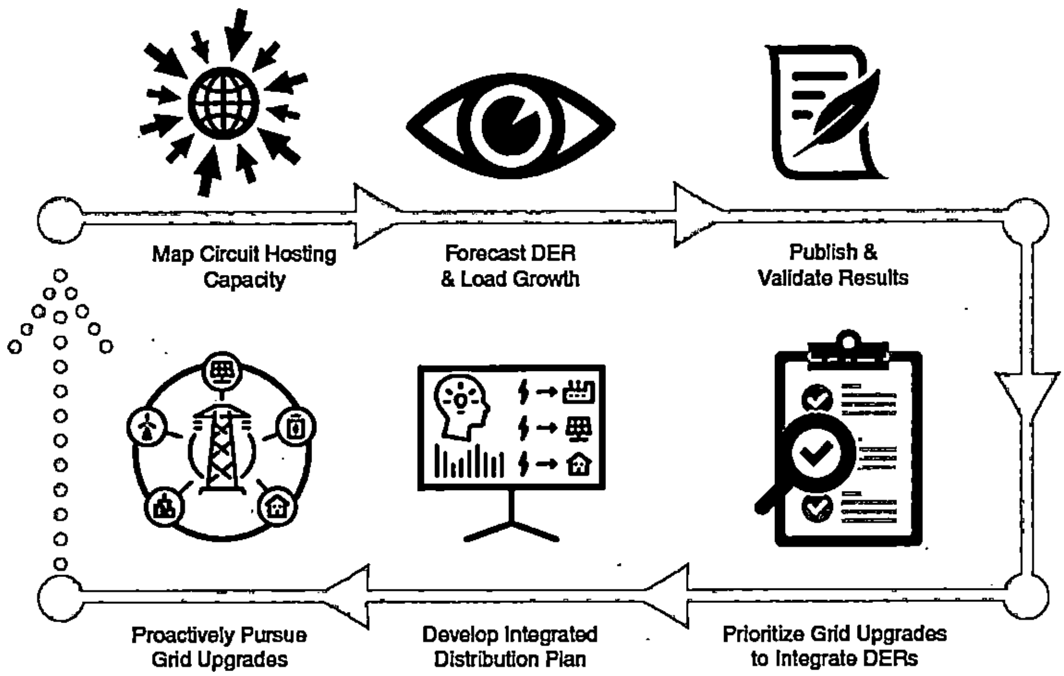


Figure 7. Integrated Distribution Planning (IDP)

layered with a corollary customer behavior analysis to see what impact, if any, such a change would have on the needs and capabilities of the distribution system under certain adoption scenarios. While this concept is not yet being implemented, there is potential to utilize the HCA in conjunction with other system planning tools to better understand how various policies and shifts in customer behavior can alter the distribution grid (which in turn should inform the long-term planning process). This aspect of the planning use case is currently under consideration in the long-term refinements phase of California's ICA working group where parties are discussing its feasibility and value and whether the existing methodologies are suited to providing accurate results for this use.[54]

3. State Experiences with the Planning Use Case for HCA

Among the states and utilities currently exploring HCA as part of their grid modernization proceedings, most have identified a role for hosting capacity in the planning process, but none have defined the planning use case with specificity. In New York, the Joint Utilities have been vague in setting forth planning as an explicit HCA use case and in providing information on how they intend to use the results of HCA to inform or improve the planning process.[55] Likewise, even after some discussion, the ICA working group in California concluded that while there was agreement that a planning use case was valuable, there needed to be further refinement of its details in order to properly evaluate the methodologies used to serve the use case.[56] As a result, stakeholders in both states have not yet had the opportunity to fully review and provide feedback and guidance on the HCA methodology most appropriate to support planning goals.

As with the interconnection use case, states are likely to get the greatest benefits from the HCA in the planning context if they clearly consider the goals of the distribution planning process and articulate a vision for how the HCA will be used to help achieve those goals. As states and utilities work to update distribution planning protocols in response to the demands and changes of the evolving electricity grid, the HCA should be considered an important tool to help achieve a more efficient, equitable and reliable grid.

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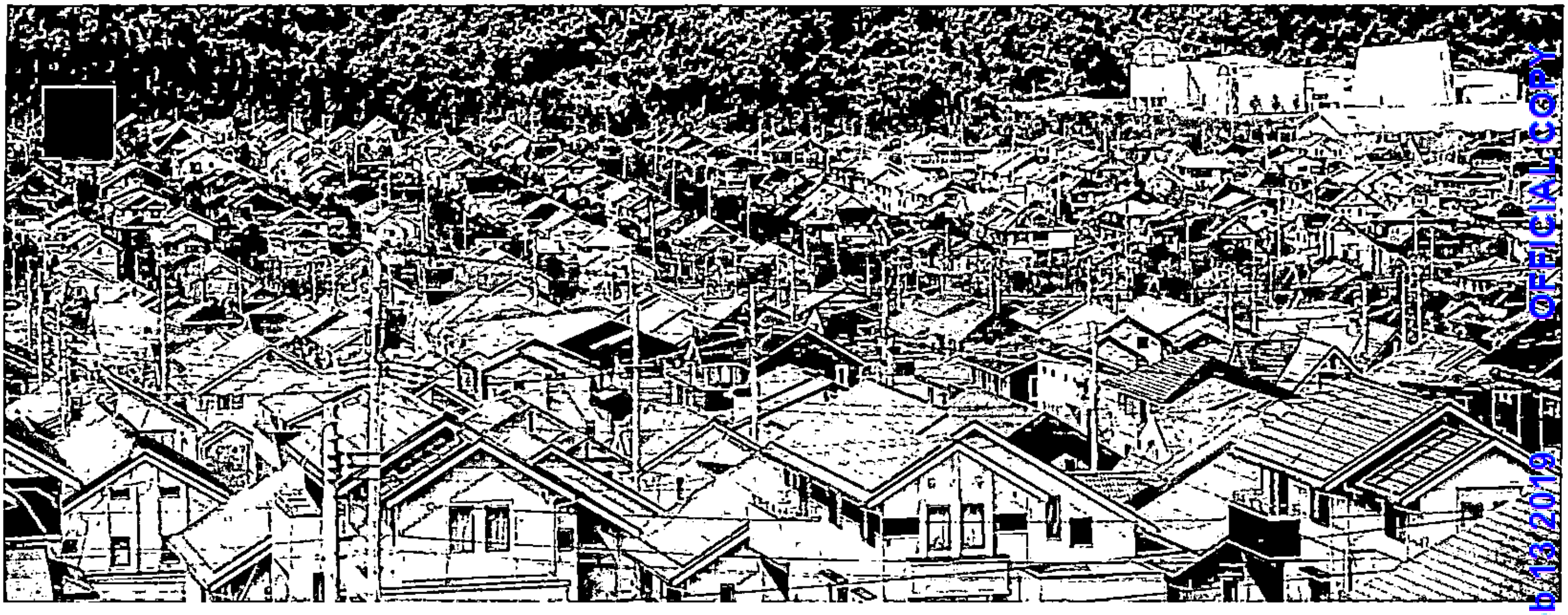
C. A COMPLEMENTARY FUNCTION: OPTIMIZING LOCATIONAL BENEFITS OF DERS

DERs have the potential to provide a range of electrical services beyond generation, capacity, and storing energy for later use. These include increasing transmission and distribution capacity, voltage support, reliability and resiliency services, equipment life extensions, and ancillary services.[57] As Southern California Edison has reported, by providing these services, DERs can increase the hosting capacity of feeders and "offset some of the load growth in an area and mitigate or even eliminate the need for capital-intensive upgrade projects."[58] DERs also provide additional environmental and public health benefits.[59] However, DERs will have greater energy, capacity, and grid values in some locations than others, depending on the characteristics and needs of the feeder and on the range of electrical services that the particular DER can provide.[60] When DER siting is effectively matched to grid needs, the DER customer, the utility, consumers, and other DER interconnection applicants all benefit.

Recognizing that the benefits of DERs may be, in some cases, location-specific has led some states to begin to develop tools to assess and identify values for DERs at precise locations on their distribution system. Separate from HCAs, locational benefits analyses can in theory be used to facilitate the matching of DER siting with grid needs by assigning greater or lesser value to DERs based on the location-dependent benefits they provide.[61] When the results of locational benefits analyses are combined with accurate hosting capacity and DER forecasting results, utilities and states will theoretically have a more robust suite of tools that can be used to deploy, direct and incentivize DERs to "optimal" grid locations (low cost and/or high benefit locations). Using these tools, programs and tariffs can then be designed to encourage DERs to operate in an optimal manner (bringing the greatest benefits to the grid) and provide compensation to the DER customers providing the benefits. "The objective is to achieve net positive value (net of costs to implement the DER sourcing) from DER integration for all utility customers."[62] However, it should be noted that extant state efforts on locational benefits analyses are not without controversy and there is not yet agreement on the methodology and assumptions underpinning such analyses (such nuances are important but are beyond the scope of this report, and thus are not discussed further).[63]

While locational benefits are not a direct use case for the HCA, since a separate modeling effort is required to identify these values on the system, the HCA is an important complementary tool to optimize locational benefits of DERs on the grid.

While locational benefits are not a direct use case for the HCA, since a separate modeling effort is required to identify these values on the system, the HCA is an important complementary tool to optimize locational benefits of DERs on the grid. At the same time that California has been working to develop the HCA, it has been developing a Locational Net Benefits Analysis (LNBA) that will identify locations where the low costs and/or high benefits of DER deployment favor increased DER activity.[64] California has proposed an updated distribution planning process that will combine the HCA with DER forecasts to develop an annual picture of the grid updates needed to support DER growth.[65] DER providers would then have an opportunity to propose DER solutions to grid needs, based on the HCA and the LNBA.[66] California may explicitly direct utilities to prioritize grid upgrade projects at locations that have both low hosting capacity and high net benefits.[67] New York is working on a similar effort through their Value of Distributed Energy Resources (VDER) proceeding. There, the state has begun to implement a valuation framework aimed at more granular determination of the temporal and locational values of DERs.[68] While the state has not yet taken this step, it could eventually pair the VDER with New York's HCA. This location-based valuation information will allow customers to assess the full costs and benefits associated with potential DER sites and direct their efforts to the most cost-effective locations.



IV. Select a Hosting Capacity Methodology Suited to Defined Use Cases

After selecting and defining use cases, the next process steps are to develop an HCA methodology (or methodologies) most appropriate to the use cases and to select criteria for implementation. Regulators play a critical role in both these steps. Clear and specific guidance from regulators ensures that the HCA effort does not become balkanized, with each utility employing a different methodology with varying suitability to statewide use cases. Regulators can also require that the methodologies and assumptions are transparent, thus ensuring the HCA produces results that are informative and instill confidence in how they are derived. Importantly, regulators also play a critical role in ensuring that the HCA is designed to address and achieve state energy policy goals.

After selecting and defining use cases, the next process steps are to develop an HCA methodology (or methodologies) most appropriate to the use cases and to select criteria for implementation. Regulators play a critical role in both these steps.

To ensure HCA efforts are meaningful for all involved stakeholders and end-users, regulators should set up a process through which they work with utilities and stakeholders to select and refine HCA methodologies and set forth implementation rules. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Utility tests of HCA methodologies can help the working group evaluate and refine the methodologies to meet identified use cases. Regulators should also create a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals.

A. THE METHODOLOGIES: STREAMLINED, ITERATIVE, AND STOCHASTIC HOSTING CAPACITY METHODS

There are an array of HCA methodologies under development and more likely on the horizon. For ease of discussion we have identified three primary methodological categories: streamlined, iterative and stochastic. They are briefly defined as follows:

- **The streamlined method** applies a set of simplified algorithms for each power system limitation (typically: thermal, safety/reliability, power quality/ voltage, and protection) to approximate the DER capacity limit at nodes across the distribution circuit.[69]
- **The iterative method** directly models DERs on the distribution grid to identify hosting capacity limitations. A power flow simulation is run iteratively at each node on the distribution system until a violation of one of the four power system limitations is identified.[70] The iterative method is also sometimes referred to as the detailed method.
- **The stochastic method** starts with a model of the existing distribution system, then new solar PV (or other DERs) of varying sizes are added to a feeder at randomly selected locations and the feeder is evaluated for any adverse effects that arise from this random allocation. The results are a hosting capacity range.[71]

While there is overlap between the methods, there is still considerable variation among the three methods in terms of basic methodological choices, results, and assumptions. Utilities and commissions may be tempted to simply select the HCA methodology that will be the least costly and least computationally complex to implement. For instance, the New York Joint Utilities and Xcel Energy in Minnesota have selected HCA methodologies based on a version of the streamlined hosting capacity method developed by EPRI—the DRIVE tool—possibly due to its computational efficiency relative to iterative methods and the off-the-shelf nature of the tool being offered by EPRI.[72] But experience from California's detailed HCA demonstration projects has shown that the version of the streamlined method used by the California utilities was not appropriate for certain use cases, particularly interconnection. It is not yet clear whether any differences between the streamlined method used in California and the one deployed by EPRI result in appreciably different outcomes, but it is clear that EPRI has not identified interconnection as a direct use case for the DRIVE tool.[73]

The failure to select an appropriate HCA methodology at the outset can lead to wasted time and money for utilities and their ratepayers if utilities must later develop and deploy a different method that is better suited and/or more appropriate to achieving the identified goals or policy objectives. As such, it is important to carefully select the methodology best suited to the state's use cases and regulatory goals. To the extent a state or utility chooses to pursue a more phased approach to HCA, a clear framework for moving through the phases and a process for iterating on and improving the HCA over time should be identified at the outset of the effort.

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It is important to recognize that the HCA methodologies available today will likely evolve and improve over time with increased use as a variety of utilities deploy them. As multiple utilities deploy and trial different methods, stakeholders are learning more about the benefits and drawbacks of each. However, over time it will likely be far less resource intensive if a consistent methodology (or methodologies) can be available and applied "out of the box" for utilities beginning the process. EPRI's DRIVE tool is a step in this direction. However, as a proprietary tool, questions remain about its capabilities and level of transparency that need to be resolved before it is clear whether this is an appropriate methodology for widespread deployment. Despite the fact that extant tools are apt to evolve over time, state regulators should not hesitate to begin the process of initiating stakeholder efforts and proceedings to define goals, identify use cases, assess utility needs, and set a timeline for statewide implementation. HCA is not only a timely tool that all states and utilities should begin exploring, but early efforts will establish an important foundation of transparency, accuracy and stakeholder consensus once the tool is adopted and implemented. Rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations.

Along with selecting a methodology, regulators should carefully consider the criteria that will guide its implementation.

B. IDENTIFY CRITERIA TO GUIDE IMPLEMENTATION OF HCA

Along with selecting a methodology, regulators should carefully consider the criteria that will guide its implementation. For instance, regulators may wish to consider:

(1) **Phasing:** Regulators may consider whether to create a phased roadmap for implementation of HCA. New York utilities, for instance, have proposed a four-stage roadmap, "with each subsequent stage increasing in effectiveness, complexity, and data requirements."[74] If a phased approach is used, regulators should ensure that the tools developed and deployed in earlier stages are compatible with the goals of later stages, and the phasing reflect the priority of the state's goals.

(2) **Frequency of updating:** Will HCA results be updated in real-time, weekly, monthly, annually, or on some other time scale? For interconnection automation and streamlining purposes, very frequent HCA results across the entire grid may be necessary. For planning purposes, less frequent updating may be required if scenarios are only needed on a periodic basis (such as annually or as appropriate). Regulators may also consider regular updating (weekly or monthly) of results for the entire grid, coupled with targeted updating of particular grid segments for interconnection purposes. For instance, the hosting capacity of the entire grid could be mapped annually, and these results could be updated incrementally each time the hosting capacity of a feeder is assessed as part of the interconnection process. The frequency of updates should align with the goals and use cases, though tempered by cost and technical feasibility.

(3) The extent of the grid covered by HCA: Will the entire distribution grid be mapped at the outset, or will only high priority portions of it be mapped initially, coupled with incremental expansion until the entire grid is analyzed? The California utilities, for instance, mapped all three-phase lines in the test areas and are exploring expanding the HCA to single-phase lines and reserving for future analysis interactions with the transmission system (such iteration of the tool is a good example of how HCA efforts can be phased over time to become more sophisticated and robust). Xcel Energy in Minnesota has proposed excluding feeders serving low voltage networks in downtown Minneapolis and St. Paul areas, which have not been previously modeled.[75] Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid can eventually be covered.

(4) DER Neutral: Making HCA agnostic to the type of DER will ensure that it remains useful as technologies and their market saturation change over time. Agnosticism is also essential for the HCA to be capable of identifying ways to expand hosting capacity or use non-wires alternatives. Under direction of the California PUC, California utilities have, for this reason, provided "agnostic" hosting capacity values "that can be used by DER providers to analyze other DER portfolio combinations."[76] They have also made an "ICA translator" available to users to determine the hosting capacity values for different types of DERs.[77] In contrast, New York and Minnesota are just focusing on solar of a certain scale in their initial analysis, and it appears that Pepco's approach is also focused only on PV.[78]

(5) Transparency Criteria: Regulators should carefully set forth the criteria for ensuring transparency in the selected HCA methodology and its results. For instance, utilities should be open about the methodology selected and any assumptions built into it. Ideally, third-parties should be able to independently test and validate the methodology to ensure its accuracy and reliability. Where multiple utilities operate in a state, regulators may also consider requiring utilities to run their respective methodologies on a test circuit and compare results. Utilities should also be open about any limitations in their analysis—i.e., to what extent it is limited in capturing the HCA under highly distributed DER scenarios, whether anticipated DER additions are built into the analysis, whether certain feeders or feeder types are excluded, whether the methodology relies on any heuristics, etc.[79]

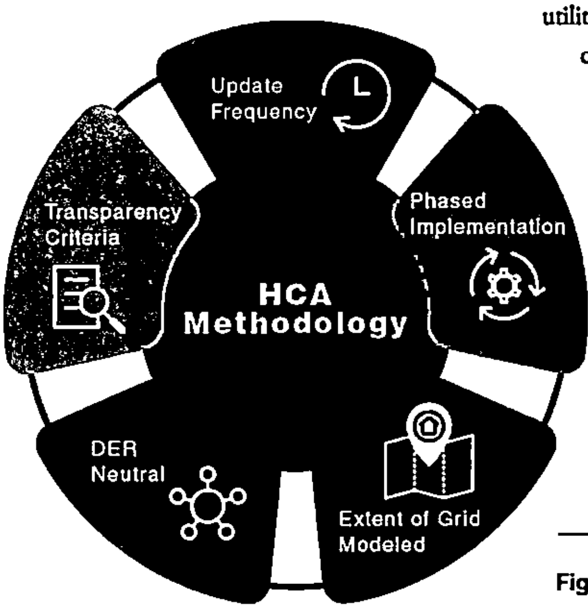


Figure 8. Criteria to Guide Implementation of HCA

C. VALIDATE RESULTS

Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Running and publishing results on test circuits and comparing actual interconnection study results will also assist in the validation process. In states like California with multiple utilities, regulators may consider requiring the utilities to run their HCA analysis on a test circuit and publicly compare results. In doing so, the California utilities were able both to confirm that they are aligned on methodology, producing largely consistent results on the test circuit,[80] and to identify areas where their different software packages and model simulations led to discrepancies so that any bugs can be worked out.[81]

D. IDENTIFY HOW DATA WILL BE SHARED

Data sharing is a key factor shaping the evolution of the electricity grid, and the sharing of data produced by the HCA will significantly impact its value as a next generation grid tool. In the hosting capacity context, data sharing enables the validation of results, allows customers to evaluate potential locations for DER siting and enables third parties to compete in offering non-wires alternatives for grid upgrades to expand hosting capacity.

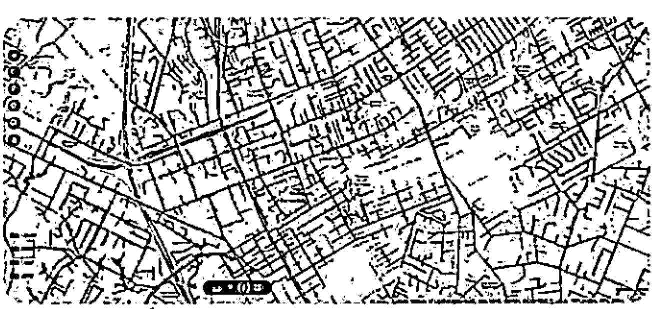
Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data.

1. Hosting Capacity Maps

Maps illustrating the hosting capacity of grid sections can be a useful tool to enable easy visualization of hosting capacity results.[82] Maps provide a high-level display of hosting capacity values on feeders throughout a circuit. Early examples of hosting capacity maps have employed color-coding of line segments and feeders according to their hosting capacity range to help customers easily identify those grid sections where DERs can be most readily interconnected.[83] They have also used quick-display boxes, allowing the viewer to easily see summary hosting capacity information for a given node or feeder.

Figure 9. Sample Hosting Capacity Maps

Source: *SDG&E, Demonstration A, Integration Capacity Map available at:https://energydatarequest.socalgas.com/ICM/*



Considerations regarding maps include:

- **Visual Display Format** What kind of color-coding, if any, should the maps employ? If color-coding is required, will all the utilities in the regulated territory be required to use a uniform color-coding system or can they select a unique color-coding system tailored to their service area?
- **Data Displays** If quick-display boxes are used, what information should utilities be required to display in those boxes? Should, for instance, the boxes include the hosting capacity value for each power system limitation, or only the overall hosting capacity at that point? Should the boxes also include basic circuit information in addition to the hosting capacity values? Will quick-display boxes be available for every node on the circuit or at less granular levels like line segment or feeder?
- **DER Technology** Will the hosting capacity maps only display data for a uniform generation profile or a standard solar PV profile? Or can they instead be filtered by the viewer to display information relevant to different DER technologies so that, for instance, different color-coding and data would appear depending on whether the viewer selects energy storage, PV with or without advanced inverters, or another DER type. If the latter, what kinds of DER technologies will be available for the viewer to select?
- **Which Data** If a blend of hosting capacity methodologies is used, which hosting capacity results will be displayed on the map? How will results be displayed if multiple scenarios are run for a circuit?
- **Data Format** Will the map data be made available in standard GIS formats?

DER customers may need access to more granular underlying data than can be easily provided through a map to file an interconnection application or design a DER to fall under hosting capacity limits. Separate considerations apply to production of maps and underlying data.

2. Downloadable Hosting Capacity Data

In addition to the maps, DER customers may need access to more granular underlying data than can be easily provided through a map to file an interconnection application or design a DER to fall under hosting capacity limits. Separate considerations apply to production of maps and underlying data.

Considerations with respect to provision of underlying data include:

- **Access** Will the underlying data be publicly accessible? How soon after the HCA is run will the publicly available data reflect the new results? Will old results be archived in a publicly available manner? Will the data be free for all users, or will there be access-related costs?
- **Content** What information will be provided in the underlying data? I.e. what hourly load profile data will be available? Will the underlying hosting capacity criteria violations be provided on the map or through the underlying data? What other types of data might be necessary to share in order to make the HCA results meaningful and actionable?

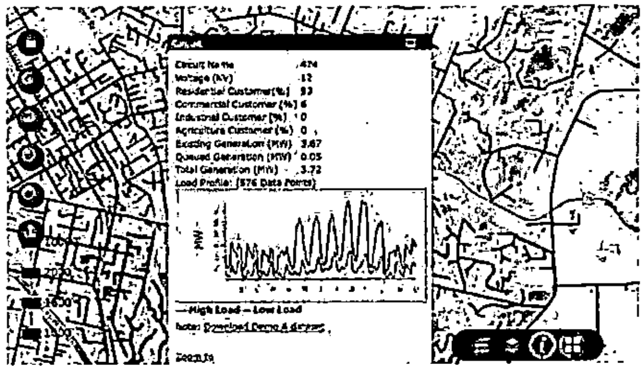


Figure 10. Sample Load Curve Data
Source: *SDG&E, Demonstration A, Integration Capacity Map, available at: https://energydatarequest.socalgas.com/ICM/*

- **Data Format** In what format(s) will the data be made available (e.g. a downloadable database, a JSON or CSV text file, etc.)? Alternatively or additionally, will the data be provided in a machine queryable fashion (e.g. through a RESTful Application Program Interface (API))? A RESTful API would allow users to query a web service running on a server operated by the utility, facilitating tailored requests for timely access to relevant raw data.[84]

- **Documentation** How will the data format or API be documented and how will the documentation be made available? Data files can be difficult to parse if the organization of the data is not well documented—for instance if the permissible values of a data field are not explained.

- **Usability** If downloadable databases are used, how will the databases be engineered to facilitate usability by customers and other stakeholders? Will they be annotated so that, for instance, a developer could identify locations by hosting capacity value and area screens?

- **Granularity** Highly granular data across a distribution circuit can result in large data files that could be practically difficult for utilities to store and users to download. An API could help overcome some of these issues. If downloadable files are instead provided, what level of granularity is appropriate to give customers the information they need without rendering the data inaccessible due to its volume? Will, for instance, hosting capacity values for every hour of a load curve be provided or rather a single value for a load curve? Are there other methods available to help manage the data efficiently without unduly constraining access?

- **Data Privacy** Should privacy concerns constrain access to the data? While it is impossible to provide perfectly anonymized data, can the data be sufficiently anonymized to overcome privacy-related constraints? Will there be a process in place to remove personally identifiable information if highly granular underlying data is provided?

- **Security** Are there any cyber or physical security considerations to take into account when sharing HCA data? If concerns are raised by utilities or others, the specific information that raises concerns should be identified so that parties can evaluate whether the HCA data sharing poses real risks, and if so, how best to manage those risks.

V. Stakeholder Engagement Strategies

A number of best practices for engaging stakeholders in the HCA development and implementation process can be garnered from the experiences of states like California, Minnesota and New York. Principal among lessons learned are:

(1) **Early and Consistent Engagement.** Stakeholder should be engaged as early as possible in the process, before critical path decisions are made. If regulators permit utilities to commit to a specific HCA method in advance, stakeholders engaged later may raise issues and insights, which show that method not to best suited to the state's needs, leading to wasted time and expense. To avoid this pitfall, stakeholders should be engaged in the process of setting and refining the uses cases and goals for HCA and involved in every step of the HCA development and implementation process thereafter, including in selecting and refining the HCA method used, in evaluating results, and in updating it as lessons are learned and methodologies improved. The back-and-forth dialogue that occurs in a working group can be particularly constructive, but this feedback can also be valuably obtained through a well-structured comment process.

(2) **Open Membership.** Membership in the stakeholder group should be open to all those who wish to participate to ensure diversity of perspectives and optimal buy-in from interested and affected communities. It may be possible to designate representative members from different groups of stakeholder interests to better manage input, but this needs to be done without unnecessarily constraining party participation. If written comments are used, there may need to be active efforts by the Commission to elicit sufficient participation to ensure an adequate range of perspectives are considered.

(3) **Neutral Facilitation and Reporting.** The stakeholder group facilitator should be carefully selected. Ideally, the facilitator will be a neutral party, either selected from within the Public Utility Commission or from a third party, rather than selected and appointed by the utilities. The facilitator should also have experience and skills in stakeholder engagement. The facilitator should ensure effective and neutral reporting of stakeholder group outcomes, including by producing detailed minutes and by either producing reports herself with stakeholder input or coordinating production of reports by involved stakeholders.

Stakeholders should be engaged in the process of setting and refining the uses cases and goals for HCA and involved in every step of the HCA development and implementation process thereafter, including in selecting and refining the HCA method used, in evaluating results, and in updating it as lessons are learned and methodologies improved.

California's Distribution Resource Plan working groups provide a useful model. The ICA (i.e., hosting capacity) working group is facilitated by a third-party consultant paid for by the utilities, but California PUC staff has oversight responsibility for the group and could assume direct management at any point to ensure meaningful stakeholder engagement.[85] The working group does its own reporting, with all stakeholders helping to draft the group's reports such that conflicting viewpoints are accurate captured for consideration by the PUC. The neutral facilitator guides the production of the reports, and while utility representatives engage in iterative discussions with the stakeholders and contribute their insights and feedback, they do not filter the reports' recommendations and conclusions. As an alternative, a working group could produce a non-utility stakeholder specific report. Utilities would then have an opportunity to file their own reports and the commission would have the two perspectives for comparison and reference in their decision-making.

If written comments are used in lieu of a working group, it is important to ensure stakeholder comments are considered by the utilities and that the decision makers are provided with a complete understanding of party perspectives.

(4) **Active Utility Engagement.** Utilities should be required to actively participate in the stakeholder process. When utilities participate only passively, stakeholders may not be informed of utility concerns and/or may feel that their concerns are not being critically considered by the utilities. There should also be checks in place to ensure that utilities are meaningfully considering stakeholder insights and revising their methods where appropriate based on those insights.

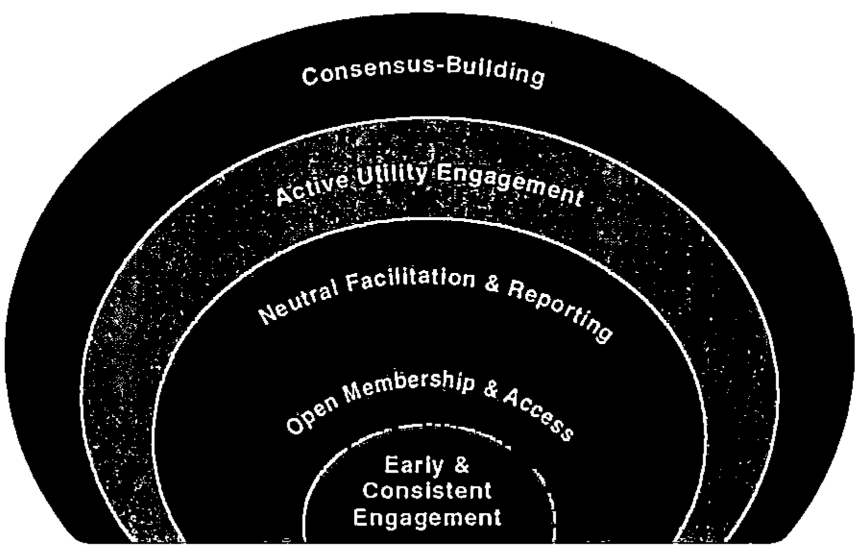
In the California ICA working group, the utility and non-utility stakeholders have engaged in productive, iterative, and ongoing negotiations, with the utilities fielding stakeholder questions, responding to recommendations and concerns, and dialoguing with stakeholders about possibilities during in-person and web-based working group meetings and in written form. This interactive process has enabled non-utility stakeholders to play a meaningful role in shaping the use cases and criteria for and the selection of an appropriate HCA methodology in California. It also helps stakeholders understand and often support utility approaches that might otherwise seem objectionable. By contrast, stakeholders in New York's Reforming the Energy Vision engagement groups reported that utilities had already made critical decisions before talking to stakeholders at engagement group meetings. And when stakeholders provided input, the utilities did not report back during the working group process about what input would or would not be taken into account, thereby allowing for the iteration and discussion that could lead to consensus. As a result, the meetings seemed to serve more as an opportunity to inform stakeholders of utilities' plans than a meaningful opportunity for stakeholders to help shape the outcome of the process.[86]

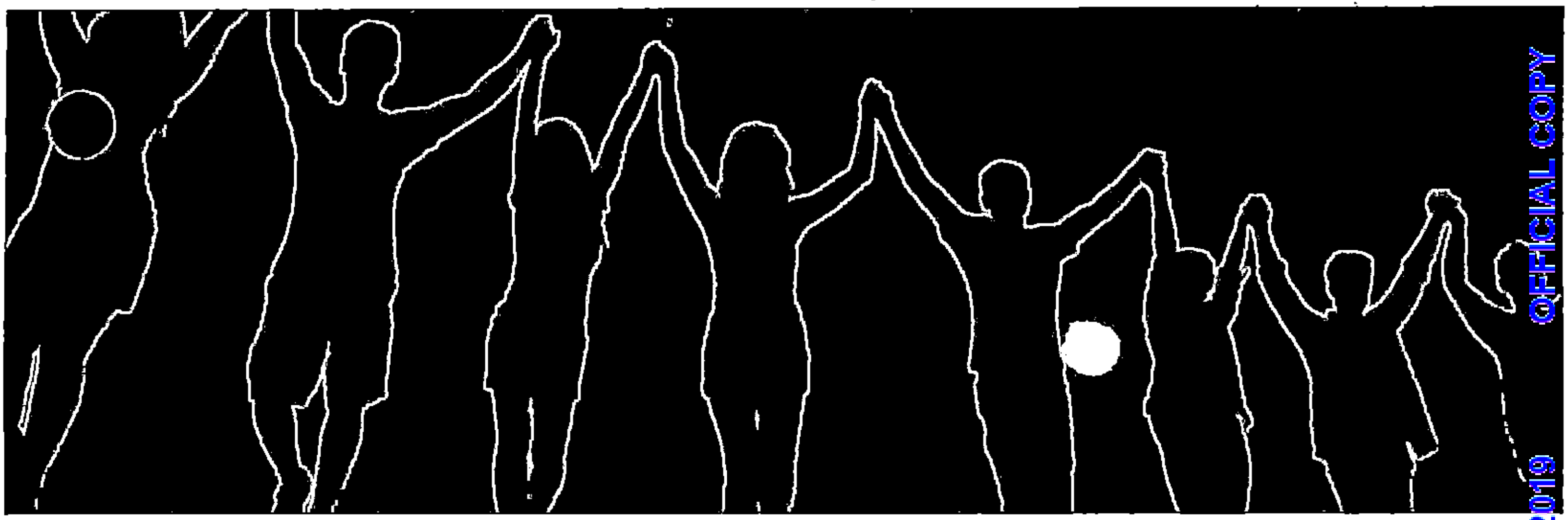
(5) **Consensus-Building:** Regulators and facilitators should ensure that the stakeholder process maximizes opportunities for stakeholders to actively voice their perspectives and concerns. Working group meetings and discussions should promote active dialogue among stakeholders in order to build consensus. Where there are areas of disagreement, there should be opportunities to communicate divergent views to utilities and regulators, including through stakeholder reports. If a hosting capacity-specific working group is convened as part of a broader grid modernization proceeding, regulators should ensure that there are opportunities to coordinate with working groups addressing other topic areas. In the New York REV proceedings, the narrowness of the engagement group topics impeded stakeholders in engaging effectively on issues with cross-subject relevance, such as tying HCA development to interconnection and planning and to questions regarding overall grid data access.[87]

(6) **Open Access.** Access to stakeholder meetings and results should be made as easy as possible. Measures to optimize access include noticing stakeholder meetings well in advance, holding meetings in a neutral location, establishing a mix of in-person and telephonic conferences (New York, for instance, held three in-person and three telephonic meetings, all run by a third-party facilitator), employing technology to maximize meaningful participation, and maintaining detailed minutes. Minutes, reports, and other stakeholder group documents should be posted in in an accessible electronic forum to allow interested parties to keep track of proceedings.

Regulators and facilitators should ensure that the stakeholder process maximizes opportunities for stakeholders to actively voice their perspectives and concerns.

Figure 11. Regulatory Stakeholder Engagement Strategies





VI. Conclusion: Realizing the Promise of HCA for All Ratepayers

As more states and utilities work to modernize the electric grid and to proactively integrate and optimize DERs on the electric system, new tools and approaches are needed. HCA has emerged as a key tool that allows utilities, regulators, and DER customers to make more efficient and cost-effective choices about deploying DER technology on the grid. HCAs can also speed up the process of interconnecting DERs since steps to expand hosting capacity will have been taken, where appropriate, prior to applications being submitted. Ultimately, as utilities plan for and pursue (or solicit from third parties) grid infrastructure improvements over time, HCAs can help ensure that DERs are optimized, not discouraged, on the system as an integrated and functional feature of affordable, quality and reliable electricity service provided to all ratepayers.

Regulators play an important role in guiding and overseeing utilities as they prepare HCA on their distribution circuits. Given the vanguard nature of this topic, regulators can and should seek to inform their efforts with lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses. Over time the software, methods and assumptions may become standardized, but in the early stages of HCA it is important that states conduct a thorough process to understand and properly vet their rollout.

Paying close attention to the process underpinning HCA efforts will help regulators realize the full promise of HCA for all ratepayers. The key process steps, recapped, are as follows:

(1) Establish a stakeholder process to work with utilities and other interested stakeholders to select, refine and implement the HCA. Ideally, this process should involve one or more working groups consisting of utility and non-utility participants with oversight from regulators to guide the HCA development. Regulators should also retain a process to improve on the selected HCA methodology over time and establish clear timelines for utilities to meet near and long-term HCA goals.

Regulators play an important role in guiding and overseeing utilities as they prepare HCA on their distribution circuits. Given the vanguard nature of this topic, regulators can and should seek to inform their efforts with lessons from the handful of states and utilities that have begun to prepare hosting capacity analyses.

(2) **Identify criteria to guide implementation of the HCA** at the outset. Working through the established stakeholder process to identify and answer key questions regarding the scope, duration, and other key elements of the HCA can help ensure a more efficient process throughout (and greater buy-in from all involved). The *frequency of updating* the HCA results, the *extent of the grid covered by HCA*, and *criteria for ensuring transparency* in the selected HCA methodology and its results are all important to discuss and define. In addition, regulators may consider whether to create a phased roadmap for implementation of HCA, depending on the level of sophistication of the utilities and the timeline for achieving state energy goals. However, care should be taken not to create an endless implementation timeline that quickly becomes obsolete or fails to miss near term opportunities for deployment and use.

(3) **Select and define the use cases for the HCA**, with input from diverse stakeholders, ensuring they are clearly designed to address and achieve identified goals, including state energy policy goals. These use cases should inform and guide the development of an HCA methodology and its implementation. There are two major HCA use cases—interconnection and planning—and a complementary function of HCA—optimizing the locational benefits of DERs. As regulators and utilities consider undertaking an HCA, it is critical that all stakeholders carefully consider and select desired use cases for HCA together at the beginning of the process. Defining use cases ensures that the cart is not put before the horse and will also prevent potentially costly and inefficient undertakings that do not produce useable results.

(4) **Develop an HCA methodology (or methodologies) most appropriate to the use cases**, providing clear and specific guidance and ensuring that the methodologies and assumptions are transparent and informative to all involved stakeholders and end-users. Regulators should ensure that the HCA methodology is scalable so that, even under an incremental approach, the full grid and range of DERs can eventually be analyzed. Currently, most HCA methodologies fit within three categories: streamlined, iterative and stochastic methodologies (though more are under development, and each individual application may have important variations). Importantly, different methodologies can result in different hosting capacity values due to different technical assumptions built into the models. Given the variety of factors that affect the grid's ability to host a wide range of DERs, it is necessary to select a well-considered methodology for determining hosting capacity based upon its intended use.

(5) **Validate the results** of the HCA over time. As with any model or analysis, real-world validation can help improve accuracy and functionality over time. Transparency in the methodology and assumptions and ready access to HCA results will ensure that they can be easily validated and any problems with the methodology identified and resolved. Ideally, sufficient information about the methodology should exist so that a third party could perform an independent analysis to validate the results reached by utilities. Regulators will need to consider the most useful manner for utilities to publish and display hosting capacity data, and set milestones over time to evaluate the performance of the HCA, relative to identified goals.

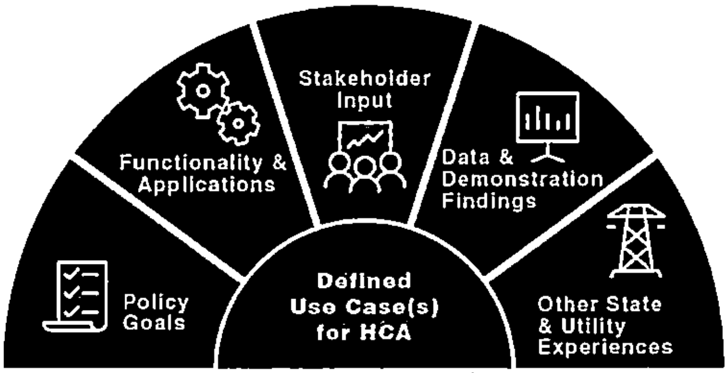


Figure 12. Key Elements to Defining Use Case(s) for HCA

In addition to the above process steps, regulators should keep in mind other key considerations, noted in the report, as they help guide and oversee the implementation of HCAs.

First, the HCA methodologies available today will likely evolve and improve over time, particularly as more utilities adopt and deploy HCA and trial different methods. Still a nascent grid modernization tool, the benefits and drawbacks of different HCA methodologies are being revealed, and likely will become even more apparent with time. Yet rather than wait for the perfect HCA methodology to emerge, regulators can take initial steps to gain familiarity and understanding of the different HCA methodologies, their function, their capabilities, and their limitations. Given the substantial investment in time, energy, and resources that HCA efforts require, there is value in taking the time early in the process to ensure that the tool being developed is capable of meeting identified objectives. Questions or concerns about what an HCA can do should be addressed before widespread implementation, lest substantial resources be invested in something that proves invaluable or ambiguously useful.

Second, requiring consistency in approaches and methodologies among utilities (where there are multiple utility services territories within a state) will help simplify the implementation and oversight process, while also ensuring a more consistent and efficient utilization of this tool among DER customers. Balkanized efforts, with each utility employing a different methodology with varying suitability to statewide use cases, will likely result in more confusion among those seeking to use the HCA and reduce efficiencies for all, including utilities and regulators. Consistent methodologies among utilities also allows for peer learning and exchange of information among utilities, which will help improve the accuracy and functionality of the HCAs over time.

Third, given swift changes to technologies, performance, and markets, HCAs should be agnostic to the type of DER to ensure that it remains useful over time. Technology agnosticism can also help utilities identify opportunities to expand hosting capacity with other DERs and deploy non-wires alternatives as part of utility grid upgrades and investment plans.

HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. Similarly, the HCA can and should be used as a tool to evaluate and understand how the hosting capacity of the distribution system might change as a result of these policies.

Fourth, data sharing remains a key factor shaping the evolution of the electricity grid, and the data collected and generated as part of an HCA will help utilities, regulators, and DER providers and customers better capture the diverse value streams of DERs. However, data sharing requires attention to related issues such as customer confidentiality, access permission, and cyber security. In this data-driven era, regulators will be increasingly tasked with balancing grid optimization, transparency and competition, consumer protections and grid security. Yet, concerns surrounding data sharing can and should be managed proactively and should not be a reason to not pursue HCAs or related efforts.

Lastly, HCAs should not be developed or implemented in a vacuum, and should be considered in the context of other policy choices and how they may impact how DERs are deployed. Similarly, the HCA can and should be used as a tool to evaluate and understand how the hosting capacity of the distribution system might change as a result of these policies. As consumers and the market responds to new programs, policies, and price signals, so too should the HCAs reflect the anticipated and planned changes to DER adoption. More robust DER forecasting methodologies will need to be developed in order to provide greater granularity and accuracy of the HCA.

As state regulators, utilities, and other involved stakeholders work to build an electricity grid better suited for the challenges and opportunities of the 21st century, the HCA will be a formative tool. Not only will HCA be a critical vehicle to improve the planning and operations of the grid, but, if deployed with intention, may also function as a bridge to span information gaps between developers, customers and utilities, enabling more productive, efficient, and cost-effective grid solutions for the benefit of all ratepayers. Regulators, with this report in hand, can provide the leadership and guidance needed to ensure the process, function, and implementation of HCA support and enable the critical grid transformations underway.

Appendix A: Case Studies on Current State and Utility Approaches to Hosting Capacity

CALIFORNIA CASE STUDY

In the Fall of 2017 the California Public Utilities Commission (CPUC) authorized full rollout of HCA across the three major IOU territories.[88] The path that California went through to arrive at this decision is both informative and instructive for other states that may be undertaking similar efforts. The process started in 2013 when the California legislature passed a bill requiring the IOUs to identify optimal locations on their grid for DERs.[89] In order to achieve this goal the CPUC determined that the utilities needed to develop "Integration Capacity Analyses" or ICA (California's name for HCA) for their territories.[90] The CPUC first required each of the utilities to develop and roll out an ICA on at least a few test feeders using a common methodology as part of their Distributed Resources Plans that were due in July of 2015.[91] From the outset, the CPUC indicated that the projects should look to support both planning and streamlining of the interconnection process.[92]

Although the CPUC specified that a common methodology was required, the California utilities—Pacific Gas & Electric (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE)—initially elected to implement different HCA methodologies in their Plans. PG&E did an initial rollout using what they called the "streamlined" method, while SDG&E and SCE utilized an "iterative" method. Following review of these Plans, the CPUC authorized the IOUs to collaborate with a stakeholder Working Group[93] to implement Demonstration Projects for the ICA that would further refine the methodologies and details prior to full system rollout. Intending to standardize their methods, the PUC initially ordered all three to implement a streamlined HCA methodology. However, after SDG&E and SCE raised significant concerns with the accuracy of the streamlined approach that had been initially deployed by PG&E,[94] the PUC, at the Working Group's urging, ordered the demonstration projects to test and compare both the streamlined and iterative methods.[95]

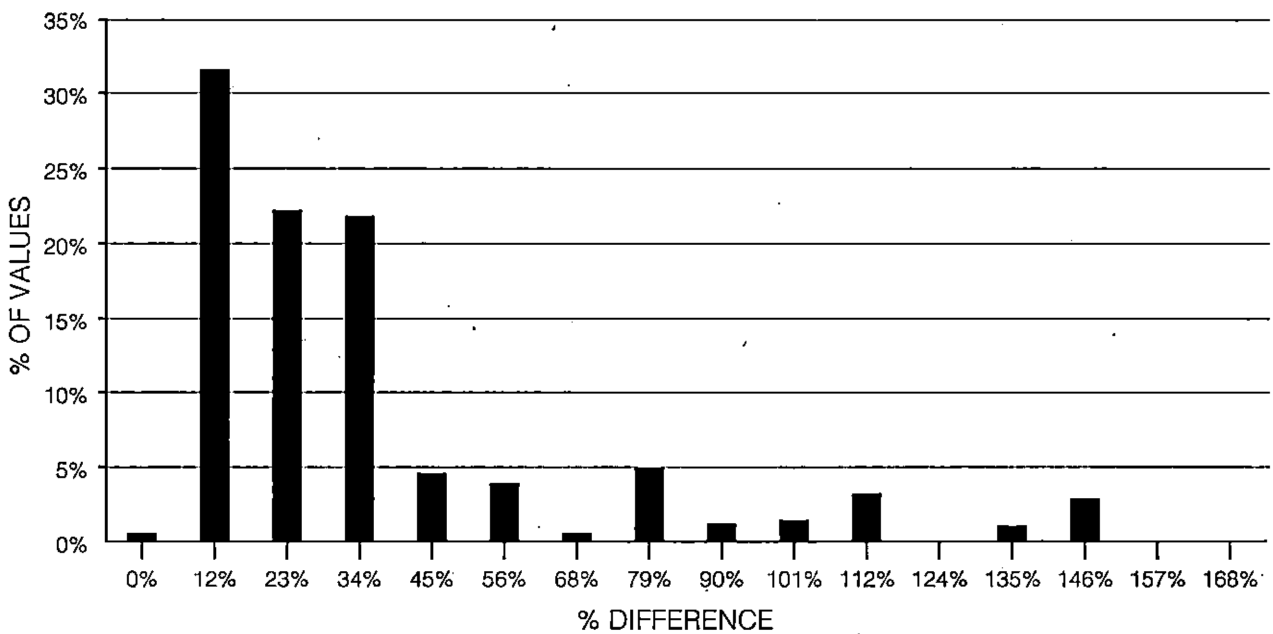
For the demonstration projects, each IOU performed an iterative and streamlined analysis of a portion of their distribution grids in an urban and a rural demonstration area within their respective service territories and additionally ran both analyses on a single test feeder to compare results and identify discrepancies across IOUs. For roughly seven months the IOUs met regularly with the Working Group to refine the details and work through challenges encountered in their development. In December 2016, the utilities published reports analyzing their results and released the HCA data through maps and downloadable data files. Regulators in other states can utilize these results and data to guide HCA methodology selection without replicating the California studies.

The California results revealed the essential tradeoff between the two approaches to be accuracy vs. computational speed. That is, the iterative method optimizes precision because it measures the actual technical capacity of the system, and it proved to be particularly well suited to complex feeders "where the streamlined approach may have difficulty in streamlining the dynamic voltage device operations on longer circuits."[96] The streamlined method, by contrast, can provide only a rough approximation of hosting capacity levels due to its reliance on abstract algorithms, however it is less data intensive and thus could allow more simulations to be run in a timely manner.[97] The discrepancy between the two sets of results varied by power system criteria and feeder location. For instance, SDG&E found that for thermal limitations, the results of the two methods were generally within 30% of each other, with the streamlined method typically resulting in a larger, but less accurate hosting capacity value.[98] By contrast, the results of the two methods were much further apart for the steady state voltage and protection criterion, with the streamlined method yielding more conservative hosting capacity values.[99] The difference in results was particularly pronounced for nodes close to the substation where the feeder's hosting capacity is at its peak and on feeders with higher numbers of voltage regulation devices.[100]

The degree of difference between the hosting capacity values returned by the two methods was surprising. For instance, while SDG&E found that the iterative vs. streamlined results differed by between 12 to 34%, the difference between the results on any one feeder could be as great as 146% (see Figure 13 below). With respect to computational speed, the streamlined approach proved to be significantly faster to perform than the iterative approach, though the discrepancy depended on software and hardware choices. PG&E, for instance, was able to reduce run times by using a combination of local machines and servers.[101] The use of cloud computing may further decrease computational times. The utilities were also able to lower run times by strategically reducing the number of hours and nodes being analyzed.

Figure 13. SDG&E Statistical Differences Between the Streamlined and Iterative Methods

Source: *San Diego Gas & Electric Company, R. 14-08-013, Demonstration Projects A & B Final Reports of San Diego Gas & Electric Company (U 902-E), Demonstration A—Enhanced Integration Capacity Analysis, p. 46 (Dec. 22, 2016)*



All three utilities concluded that the iterative approach is better suited for analyzing circuit conditions for interconnection purposes, although they shared concern about the computational demands of that approach.[102] By contrast, the utilities suggested that the streamlined approach may be more applicable for a planning use case because of its ability to efficiently perform scenario analyses.[103] As a consequence, the utilities initially recommended utilizing a blended approach, with iterative analysis used for interconnection and streamlined use for planning, and PG&E further suggesting that both methods should also be used together for the interconnection use case.

The Working Group intensively analyzed these results in making its recommendation to the CPUC on how to proceed. As part of this effort the group defined what the precise goals were for the interconnection use case and compared the ability of the different methodologies to achieve those goals. The Working Group found that due to the relative inaccuracy of the streamlined method that it was inadequate to support the goal of substantially automating the interconnection process for projects falling within the identified hosting capacity. All but PG&E agreed, thus, that the iterative methodology should be used for the interconnection use case. PG&E recommended using a combined method,[104] but the CPUC ultimately adopted the recommendation of the majority of the Working Group.[105]

With respect to the planning use case, the Working Group found that it required further development before it could adequately assess which methodology or combination of methodologies would best serve the needs of that case. The Group thus agreed to continue working on refining this use case during 2017 and a decision will come in 2018 which will determine how the ICA can be used to best achieve the refined goals of the planning use case.[106]

Refinement of the use cases and selection of the core methodology was not the only focus of the Working Group. The Group also worked with the utilities to agree upon how the results would be displayed on the publicly available maps, what data would be made available for download, and how to address particularly methodological hurdles regarding operation of voltage regulating devices, smart inverters and other system issues.

Regulators can learn a great deal from evaluating the California experience and results:

- The California experience illustrates the importance of a carefully designed and inclusive process for HCA methodology selection. While the demonstration projects ultimately used have been highly valuable, time and expense could have been saved by putting into place at the outset a process to compare HCA methods. This process made sense in California as this was really the first full rollout done through a public process, but the issues discussed are not unique to California and thus other states can likely jump ahead if they build on this experience.

- The California demonstration project results provide a helpful analysis of the tradeoffs between streamlined and iterative methodologies and a framework for evaluating their suitability to the different use cases. In general, they reveal that, between the two methods as designed at the time, only the iterative analysis produced accurate enough results for use in interconnection decision making. While the streamlined method may have value for planning because of its suitability for scenario analysis, it remains unclear whether the streamlined method can be made accurate enough for interconnection or planning purposes. As in other states, the lack of a precise definition and goals for the planning use case has impeded the ability to make this determination.

- Working groups and utilities should explore ways to revise methodologies to overcome obstacles. It may be possible to reduce hour and node profiles for the iterative method, for instance, to shorten computational times without unduly sacrificing accuracy. Likewise, different hardware choices (i.e. use of servers and cloud computing) can significantly speed up computing. Regulators should make sure that when utilities report on computational challenges, they also report on the expense associated with overcoming them.

- When tests of HCA methodologies are performed, raw data should be released along with analysis of results to help working group participants and third parties provide the most useful feedback.

- Dialogue between utility and non-utility stakeholders is critical in selecting and refining the HCA methodology and can be done in a constructive and collaborative manner with the right framework in place.

NEW YORK CASE STUDY

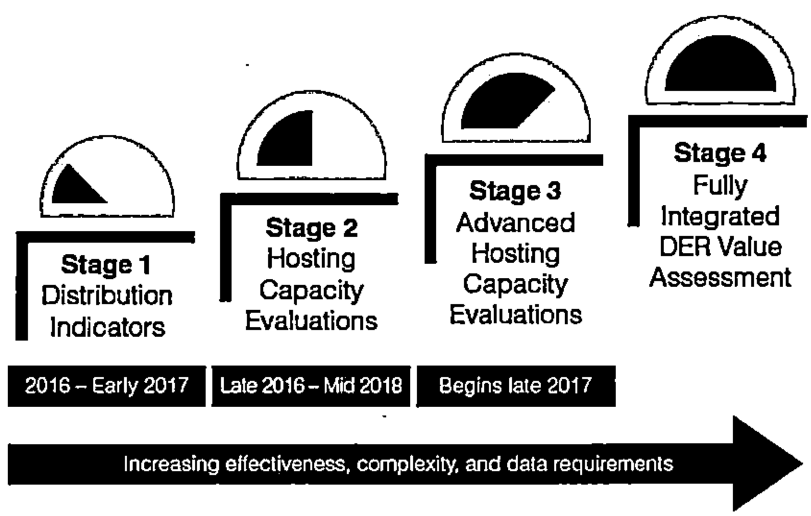
The efforts to develop HCA in New York arose as part of the state's Reforming the Energy Vision (REV) proceeding.[107] In 2015, the New York Public Service Commission (NY PSC) required the utilities to include hosting capacity efforts in their Distributed System Implementation Plans (DSIPs).[108] The NY PSC required the utilities to develop a common methodology and publish the known hosting capacity for all circuits on a map that includes relevant system information. The NY PSC did not initially specify the granularity of the analysis or the frequency with which it would be updated. Though the NY PSC alluded to the general value of having hosting capacity information, it did not identify use cases for the HCA to instruct the utilities in their selection of methodology or the ultimate functionality desired. The NY PSC ordered the utilities to engage with stakeholders around all aspects of their DSIPs, but did not require a specific structure for incorporating the feedback or for documentation of stakeholder input.[109]

The Joint Utilities[110] collaborated with the Electric Power Research Institute (EPRI) on the preparation of a paper that outlined the tiered approach the utilities would use to develop their hosting capacity analyses.[111] The paper and subsequent DSIPs identified that hosting capacity can be used to "inform" interconnection, planning and the identification of locational value.[112] The Joint Utilities chose to utilize EPRI's proprietary DRIVE tool,[113] which utilizes a version of the streamlined methodology that was also tested in California.[114] The utilities proposed using a four-tiered approach for the analysis, each step in the process is intended to add greater detail and granularity as utility data sets and modeling tools evolve.[115] The four steps identified were to develop: 1) distribution indicators, 2) hosting capacity evaluations, 3) advanced hosting capacity evaluations, and 4) fully integrated DER value assessments.[116] The first step involves each utility publishing a map with basic information about circuits (i.e. voltage of the line, already connected generation, etc.); these maps do not include any data analysis of the circuits. The second step entails the first iteration of the HCA, where the utilities will publish ranges of potentially available capacity. The HCA at this stage is only evaluating the hosting capacity for large-scale solar and not providing information on the capacity for small solar or other types of DER (e.g. electric vehicles or energy storage). In addition, the hosting capacity model does not include in the analysis DERs that are already connected to the grid.[117] Less detail is available on exactly what will be included in the third iteration, but it may include analysis down to the nodal level and further modeling of "operational flexibility" constraints.

Despite widespread dissatisfaction with the approach laid out by the utilities,[118] the Commission's Order largely approved the utilities' plans, however it required that they move ahead on a faster timeline, requiring that the stage 2 analysis be completed for all 12 kV circuits and above by October 1, 2017.[119] The NY PSC also required that basic information about the feeder be published in the maps, that the presentation of the data be more consistent across the utilities, and that some data be available to download.[120] The NY PSC approved the utilities plan to only update the analysis on an annual basis, with monthly updates of the interconnection queue data.

Figure 14. Joint Utilities of New York Hosting Capacity Road Map

Source: *New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 48 (Nov. 1, 2016)*



While the process underway in New York is certainly likely to produce considerably more information than has ever been available to third parties about the state of the distribution system in New York, it is unclear how valuable the results will be to guiding decision making, either in the regulatory context or for specific investment decisions by third parties. The NY PSC has thus far declined to identify specific use cases for the analysis and made no specific plans for ultimately being able to utilize this information in processing interconnection applications or in the distribution planning process. There also has not been any demonstration of the accuracy of the results of the methodology which will need to be done if the tool is to be used for decision-making purposes going forward.

Lessons learned from the New York process:

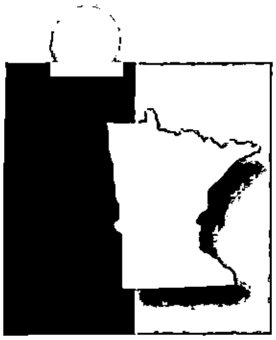
- The four-tiered approach in New York provides an illustration of how a state may approach the rollout of an HCA in a manner that will provide more detailed information over time as data and methodology improves.

- The New York experience illustrates some of the challenge of not identifying clear uses cases prior to commencing selection and development of the technical methodology for the HCA. Since there was no identification of desired uses, it is not clear exactly how the information coming out of the HCA produced will be used to guide or inform decision making.

- States should strive to ensure greater public transparency and vetting of the chosen methodology through the regulatory process. Thorough vetting of the methodology through publicly available studies, test runs, or comparative tests can demonstrate the accuracy of the tool and the relative consistency in its application across utility territories. Conducting this process publicly can utilize the collective knowledge of a wider range of stakeholders and also ensure broader support and confidence in the outcomes of the HCA.

- Commencing stakeholder engagement prior to utilities having made major decisions about methodology and approach increases the likelihood that utilities will not be path dependent by the time they reach out to stakeholders and will also help to ensure that the tool is designed to serve customers' needs. In addition, the stakeholder engagement process should be structured to ensure that stakeholder feedback is objectively recorded and reported on the record for review by regulators regardless of whether input is ultimately taken by the utilities.

- Including one segment of one type of DER (large scale PV) in the initial methodology may be an appropriate interim step from a resource standpoint, but it places severe limits on the usefulness of the information for expanding hosting capacity and allowing DERs to be used to address constraints on the system.



MINNESOTA CASE STUDY

HCA in Minnesota arose out of a 2015 statutory directive requiring Xcel Energy to file information regarding the interconnection of small-scale distributed generation (DG) projects within the biennial transmission planning process.[121] As part of this process, the Minnesota Public Utility Commission (MN PUC) required Xcel to complete an analysis of the hosting capacity of each feeder on Xcel's distribution system for DG of 1 MW or less and to identify potential distribution system upgrades necessary to support expected DG growth.[122]

On December 1, 2016 Xcel filed a distribution system study containing its initial HCA results.[123] As did the New York Joint Utilities, Xcel elected to use EPRI's proprietary DRIVE tool to assess the hosting capacity of individual feeders through a streamlined hosting capacity method. The DRIVE tool provided Xcel with a choice of three DER deployment scenarios to allocate DER across a feeder: large centralized, large distributed, and small distributed. Of the three, Xcel selected the small distributed generation scenario, which it deemed consistent with the PUC order's focus on small DG resources. Xcel ran the analysis on more than 1,000 feeders in its distribution system.[124] Owing to limitations in the DRIVE tool, Xcel did not include in its analysis existing or forecasted DERs, and it did not apply mitigations to determine if hosting capacity could be increased.[125] Xcel published its results in a summary chart that reported for each feeder the minimum and maximum hosting, the limiting violation, and the currently installed and proposed DG.[126] The initial report did not include a map showing the hosting capacity or any downloadable data in a sortable form.

The MN PUC initiated a new round of commenting on Xcel's hosting capacity study. The PUC issued an information request to Xcel requiring that the utility issue responses to a list of questions intended to clarify Xcel's hosting capacity model and to assist stakeholders in providing comments.[127] And it invited public comments on Xcel's hosting capacity report and its supplemental comments in response to the MN PUC's information request.[128] The MN PUC then held a public meeting at which stakeholders were given an opportunity to present their positions on Xcel's filings and the proposed MN PUC action.[129]

After considering stakeholder written and oral comments, the MN PUC issued an order on August 1, 2017 in which it set forth guidance for subsequent hosting capacity reports by Xcel.[130] The order required Xcel to file hosting capacity reports on an annual basis with sufficient detail to provide customers "with a starting point for interconnection applications" and "to inform future distribution system planning efforts and upgrades necessary to facilitate the continued efficient integration of [DG]."[131] The PUC directed Xcel to display the annual hosting capacity results in a color-coded map representing the available hosting capacity of Xcel's distribution grid down to the feeder-level and to provide downloadable hosting capacity results in spreadsheet format.[132] The PUC also directed Xcel to include in its November 1, 2017 report information requested by staff and parties through comments on its 2016 report and information on the accuracy of its hosting capacity results, including by conducting a comparison of results in its 2016 report with actual hosting capacity determined through interconnection studies.[133]

Xcel filed this updated HCA and supporting information requested by the MN PUC on November 1, 2017.[134] The New HCA includes some additional improvements and refinements, including the incorporation of existing known DERs, a change from modeling small DERs to instead using the "large centralized" DER option in DRIVE, and inclusion of some changes to allow for limited modeling of certain smart inverter and voltage regulation devices.[135] The results are now also published on a publicly available map.

In parallel, the MN PUC has begun considering HCA as part of its broader Grid Modernization proceeding, initiated in 2015. The PUC issued a distribution system planning questionnaire in which, among other things, it directed Minnesota's three investor owned utilities—Xcel, Minnesota Power, and Otter Tail Power Company—to report on any HCA they currently conduct, and invited cooperative and municipal utilities to do the same.[136] And it solicited comments from all stakeholders on the form that analysis should take.[137] The MN PUC has not yet clarified to what extent hosting capacity will be part of this broader proceeding and how it will relate to the separate Xcel proceeding.

The Minnesota proceedings are a unique case study in several respects: they have thus far utilized a predominantly written commenting process for stakeholder engagement with respect to hosting capacity; they represent one approach to tailoring hosting capacity requirements to utilities of very different sizes and types of service areas; and they have created parallel tracks within which HCA can be addressed.

Lessons learned from Minnesota include:

- The Minnesota experience highlights strategies for meaningfully incorporating stakeholder input through written comments. At each stage of Xcel's hosting capacity proceeding, the MN PUC solicited written comments from stakeholders, and it transparently considered and incorporated feedback into its recommendations and directives. The MN PUC demonstrated its consideration of stakeholder positions by summarizing comments in its orders and by directing the utilities to answer specific questions about their methodologies. Outcomes reflect the MN PUC's consideration of stakeholder input. For instance, the MN PUC's order on Xcel's hosting capacity report directed Xcel to address stakeholder concerns with the accuracy of its hosting capacity methodology.[138] Xcel responded with additional information on the methodology[139] and the Commission has invited stakeholder comments on Xcel's response.[140]

- The Minnesota experience suggests that solicitation of written comment can be particularly effective for considering stakeholder feedback on technical components of HCA. But it may have limitations when used as the only method to engage stakeholders in the broader policy dimensions of hosting capacity. In response to the MN PUC's questionnaire in its distribution study proceeding, a number of stakeholder groups recommended that the MN PUC couple written comments with working groups or workshops, particularly for developing hosting capacity goals and use cases.[141]

- Xcel is by far the largest utility in Minnesota but others—Minnesota's two smaller investor owned utilities and its municipal and cooperative utilities—are important players. The MN PUC has accounted for these distinctions by, consistent with the statutory directive, requiring Xcel to be the first mover in developing HCA while engaging all utilities in the exploration of hosting capacity in its distribution system planning proceeding. This latter proceeding represents a valuable potential opportunity to formulate hosting capacity goals and use cases applicable to all utilities as well as timelines tailored to the respective utilities' systems and needs.

- The Xcel hosting capacity proceeding, similar to the experiences in California and New York, illustrates the drawbacks of mandating HCA before establishing goals and use case. Significant concerns have been raised with the accuracy of Xcel's methodology and the usefulness of its results, and it remains to be seen whether the DRIVE tool can be tailored to meet the needs of the use cases ultimately selected. Significant costs and delays could be avoided by beginning with the broader policy discussion.

- Xcel's method initially focused on small DG and its most recent version focuses on large DG, although neither scenario is a likely representation of expected DG growth (which will likely include a mix of both small and large DERs). The initial version of its hosting capacity did not incorporate installed and pending DER, but the most recent version now includes installed DERs.[142] There have been a number of other improvements between the first and second iteration. However, stakeholder concerns regarding the lack of transparency of the DRIVE tool, which hinders their ability to provide effective feedback on its capabilities and limitations, persists.[143]

- The MN PUC has thus far considered hosting capacity as a guide for interconnection filings rather than a method that could eventually automate—or nearly automate—the interconnection process. This way of thinking may limit the state's broader grid modernization efforts or result in substantial costs if utilities are required to reinvent their hosting capacity methods when the interconnection use case changes.

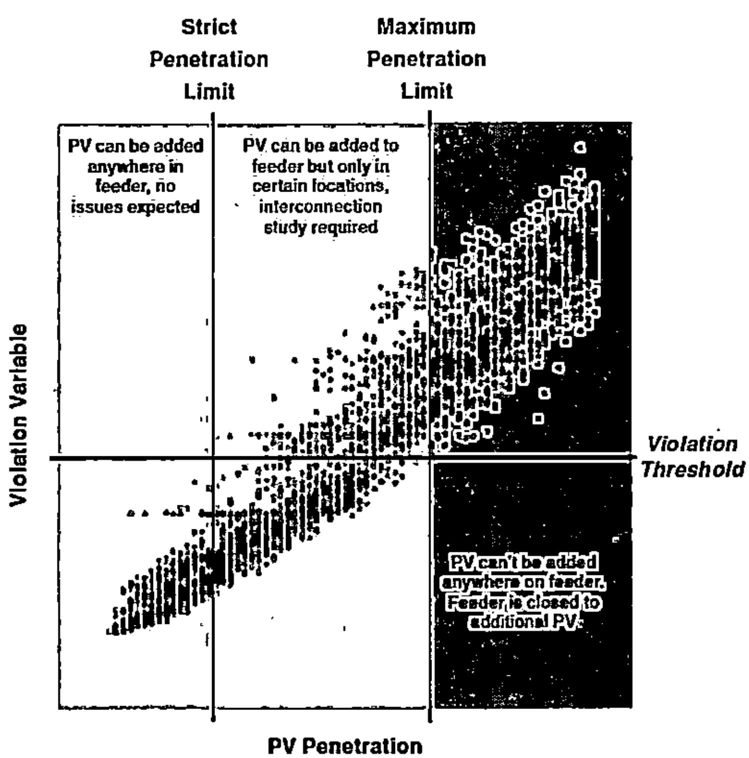
PEPCO CASE STUDY

Pepco Holdings, Inc. was one of the first utilities to deploy a hosting capacity model across their service territory which covers parts of New Jersey, Maryland, Washington D.C., and Delaware. Coming out of a study funded by the DOE in 2015, Pepco's model utilizes what is known as the "stochastic method" to determine the hosting capacity of its feeders.[144] Rather than identifying a specific hosting capacity amount for a feeder, the method runs various scenarios with solar PV randomly placed on a feeder to determine a range of possible hosting capacity figures. The chart below provides a visualization of the results of this method.[145] The green area on the left shows the scenarios that were run where no violations of hosting capacity limits would occur regardless of PV location, the yellow area shows scenarios where potential PV could be located without violations, but only in certain locations (thus a study might be required), and the area in red shows scenarios where there would be an absolute violation of the circuit limits regardless of location.

Pepco has begun to use the results of this analysis to help streamline the interconnection process in their territory. Using their HCA Pepco identifies "restricted circuits" on their system, which are circuits where "a major distribution infrastructure investment would be required to allow the DER to interconnect without creating a violation of utility system

Figure 15. Pepco Definition of Strict and Maximum PV Penetration Limits

Source: *Pepco Holdings, Inc., Model-Based Integrated High Penetration Renewables Planning Control and Analysis, p. 11 (Dec. 14, 2015)*



operational parameters."[146] There are three categories of restricted circuits: (1) those that are restricted to all sizes, (2) those that are restricted to systems below 250 kW, and (3) those that are restricted to systems below 50 kW.[147] Pepco publishes their hosting capacity map (or "restricted circuit map") on their website (updated at least quarterly) which color codes circuits based upon their restriction category.[148] Pepco is able to streamline the interconnection process for projects not located on a restricted circuit, or for those sized below the circuit restriction level, as long as they also meet a set of "criteria limits" the utility has defined.[149] While this approach has value in reducing the amount of individualized review that projects receive in the interconnection process, it may also underestimate hosting capacity for certain projects and provides a less precise result to guide the design of projects seeking to maximize hosting capacity. As part of the DOE project, Pepco has also identified mitigation strategies for increasing hosting capacity on a circuit.[150]

Pepco initiated this process absent any formal regulatory requirement as a way to help better manage their distribution system and the interconnections to that system. While this proactive approach by the utility can lead to some immediate and positive outcomes for customers, there are potential drawbacks to proceeding with a significant HCA rollout without the benefit of a robust stakeholder process. The HCA methodology used and the limits and assumptions built into that methodology have not undergone any public vetting for fairness or accuracy. Since the HCA is being used to facilitate, but also restrict, interconnection access it is important that regulators ensure that methods used are reasonable and valid.

Appendix B: References

Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (June 2013)

IREC, *Integrated Distribution Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources* (May 2013)

IREC, *Easing the Transition to a More Distributed Electricity System* (Feb. 2015)

EPRI, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State* (June 2016)

EPRI, *Alternatives to the 15% Rule* (Dec. 2015)

EPRI, *Integration of Hosting Capacity Analysis into Distribution Planning Tools* (Jan. 2016)

EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012)

Solar Energy Industries Association, *Hosting Capacity: Using Increased Transparency of Grid Constraints to Accelerate Interconnection Processes* (Sept. 2017)

Solar City, *Integrated Distribution Planning: A Holistic Approach to Meeting Grid Needs and Expanding Customer Choice by Unlocking the Benefits of Distributed Energy Resources* (Sept. 2015)

ICF International, *Integration Distribution Planning*, Prepared for MN PUC (Aug. 2016)

Regulatory Assistance Project, *Electricity Regulation in the United States: A Guide* (2d ed. June 2016)

Endnotes

1 The term Distributed Energy Resources, or DERs, refers to resources located on the distribution system (in front of or behind the customer meter). These resources may vary by jurisdiction. For purposes of this paper, the term includes distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The impact on hosting capacity varies significantly between DER technologies depending upon whether the technology is a new load source (e.g. electric vehicles), a load shift or reduction (e.g. demand response), a generating resource (e.g. solar PV) or some combination of these (e.g. energy storage).

2 A node is a point on a feeder between two line sections. Circuit characteristics may be analyzed at each selected node along the circuit.

3 Tim Lindl, et al., *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources*, IREC and Sandia National Laboratories (May 2013) ("IDP Concept Paper"), http://www.irecusa.org/publications/integrated-distribution-planning-concept-paper/.

4 For examples of state grid modernization proceedings that integrated IDP, see Cal. Public Utilities Commission, Distribution Resources Plan Dkt., R. 14-08-013; NY Public Service Commission, Reforming the Energy Vision Dkt., Case 14-M-0101; and MN Public Utilities Commission, Staff Report on Grid Modernization, pp. 15-16 (Mar. 2016) (identifying integrated distribution planning as the first of nine key steps to explore in Minnesota's grid modernization efforts).

5 As used throughout this paper, the term "use case" refers to the primary function and/or application of the hosting capacity analysis. Refer to Section II.B for additional information.

6 Appendix B to this report provides a compilation of recent resources on hosting capacity and related distribution planning and interconnection topics.

7 *See* Electric Power Research Institute ("EPRI"), *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, p.3 (June 2016) ("Defining a Roadmap") (defining "hosting capacity"); *see also* Cal. Public Utility Commission, R. 14-08-013, Assigned Commissioner's Ruling Re. Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans, Attachment pp. 15-16 (Nov. 17, 2014) (introducing Integrated Capacity Analysis ("ICA") as a tool for determining distribution system hosting capacity).

8 *See, e.g.*, Defining a Roadmap at p. 10 (summarizing these four power system criteria); San Diego Gas & Electric Company, R. 14-08-013, Demonstration Projects A & B Final Reports of San Diego Gas & Electric Company (U 902-E), Demonstration A—Enhanced Integration Capacity Analysis, p. 30 (Dec. 22, 2016) ("SDG&E Final Report A") (explaining that the Assigned Commissioner's Ruling required the three California investor owned utilities to examine these "four major categories of power system criteria . . . to determine the DER integration capacity for the nodes and line sections on each distribution feeder"); *id.* at pp. 34-39 (describing the four criteria and their role in hosting capacity analysis).

9 Solar City, *Integrated Distribution Planning: A Holistic Approach to Meeting Grid Needs and Expanding Customer Choice by Unlocking the Benefits of Distributed Energy Resources*, p. 5 (Sept. 2015) ("Solar City IDP") (HCA "provide[s] an indication of how many DERs can be accommodated given existing utility and customer-owned equipment on a circuit").

10 EPRI; *Alternatives to the 15% Rule: Final Project Summary*, p. xii (Dec. 2015) ("Minimum hosting capacity is defined as the lowest amount of PV that causes the first violation on a feeder.").

11 EPRI, *Integration of Hosting Capacity Analysis into Distribution Planning Tools*, pp. 3-4 (Jan. 2016) ("EPRI Integration").

12 *Id.* at p. 3.

13 The hosting capacity of a feeder can also vary depending on the type of scenario selected—such as centralized versus highly distributed DERs and whether backfeed through the substation is permitted. *See* Defining a Roadmap at pp. 11-12.

14 Smith, Jeff and Matthew Rylander, PhD, *Overview of Hosting Capacity Methods: Detailed and Streamlined Methods*, Electric Power Research Institute, presented to the California Integration Capacity Analysis Workgroup, slides 9-10 (June 9, 2016), http://drpwg.org/wp-content/uploads/2016/06/EPRI_Hosting-Capacity-Methods_Smith.pdf.

15 *Id.* at p. 8; see also Pacific Gas & Electric Co., R. 14-08-013, Pacific Gas & Electric Company's (U 39 E) Demonstration Projects A & B Final Reports, Appendix A (Demonstration Project A—Enhanced Integration Capacity Analysis), pp. 146-55 (Dec. 27, 2016) ("PG&E Final Report A")

(describing metrics set out by the California PUC for utilities to meet in developing and testing ICA methods).

16 See Solar City IDP at p. 2; Erica McConnell & Cathy Malina, *Interconnection: The Key to Realizing Your Distributed Energy Policy Dream*, Greentech Media (Oct. 25, 2016), https://www.greentechmedia.com/articles/read/interconnection-the-key-to-realizing-your-distributed-energy-policy-dream#gs.ppLHx9k.

17 K. Ardani, et al., *A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*, National Renewable Energy Laboratory, p. 13 (Jan. 2015).

18 See NC Utilities Comm., Dkt. E-100, Sub 101A, Duke Energy Carolinas, LLC, Quarterly Interconnection Queue Performance Report (Oct. 20, 2017) (over 61% of projects take between 360 to over 990 days from entering queue to receiving interconnection agreement).

19 For a more thorough discussion of the benefits of data sharing in the interconnection process, see Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp#gs.SVY9Tdw.

20 For more information on the background of interconnection screening see Kevin Fox, Sky Stanfield, et. al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratories, p. 2-10 (Dec. 2012).

21 See EPRI, *Alternatives to the 15% Rule: Final Project Summary*, p. vii (Dec. 2015)

22 *See Integrated Distribution Planning: Prepared for Minnesota Public Utilities Commission*, ICF International, p. vi. (Aug. 2016) ("ICF IDP") ("There is a recognition nationally by utilities, stakeholders, and regulators that improvements to processing and studying interconnection requests are needed to meet customers' expectations and manage work flow."); PG&E Final Report at p. 156 (reporting that the iterative method "could help streamline Fast Track studies and improve the outdated methods such as the 15% rule in screen M"); Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track. Issues, , Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 1 (Aug. 2017) ("The use of circuit hosting capacity by the Hawaiian Electric Companies . . .has resulted in additional interconnection approvals." and "Circuit hosting capacity facilitates faster interconnections.").

23 *See* Cal. Public Utilities Commission, R. 14-08-013, Protest of the Interstate Renewable Energy Council, Inc. to Applications of San Diego Gas & Electric Company, Pacific Gas & Electric Company, and Southern California Edison Company for Approval of their Distribution Resources Plans, p. 23 (Aug. 31, 2015) ("IREC Protest of DRP Applications").

24 *See id.* at p. 22.

25 Pre-application reports provide readily available information about a particular point of interconnection on a utility's system. The information generally provided includes items such as the circuit and substation voltage, the amount of already connected and queued generation, the distance of the proposed point of interconnection to the substation, and peak and minimum load data. These reports are available in a handful of states where they help guide customers. But they have limitations: they do not contain any actual system analysis and can take over a month to receive. See Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (Jan. 31, 2017), https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improves-the-interconnection-exp#gs.SVY9Tdw; Zachary Peterson, The State of Pre-Application Reports, National Renewable Energy Laboratories (June 2017), https://www.nrel.gov/dgic/interconnection-insights-2017-07.html.

26 *See, e.g.* Quarterly Interconnection Reports for the California Investor Owned Utilities, http://www.cpuc.ca.gov/General.aspx?id=4117 (these reports show the number of pre-application reports that have been requested in recent years; although, given their relative newness, efforts to collect more comprehensive data to measure their full impact on interconnection applications are still underway).

27 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling on Guidance For Public Utilities Code Section 769—Distribution Resource Planning, Attachment (Guidance for Section 769—Distribution Resource Planning), p. 3 (Feb. 6, 2015) ("Final CPUC Guidance").

28 *Id.*

29 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling (1) Refining

Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016); *see also* Cal. Public Utilities Commission, R. 14-08-013, Email Ruling of Administrative Law Judge Mason (June 10, 2016) (authorizing the utilities to conduct a comparison of both methodologies in their demonstration projects).

30 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, pp. 7-14 (Mar. 15, 2017).

31 Cal. Public Utilities Commission, R. 14-08-013, Decision 17-09-026, Decision on Track 1 Demonstration Projects A (Integration Capacity Analysis) and B (Locational Net Benefits Analysis), pp. 29-33 (Sept. 28, 2017) ("CPUC Decision on Track 1 Demonstration Projects").

32 Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track. Issues, Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 5 (Aug. 14, 2017) (HECO's "analysis is closer to that of an iterative methodology, where simulations are run until a hosting capacity number (with no criteria violations) is determined, which the [California] IOUs concluded yields higher hosting capacity values and more accurate results.").

33 *Id.* at p. 4 ("The [Hawaiian Electric] Companies have three use cases for the circuit hosting capacity analysis, applying it as a tool to (1) streamline the interconnection process for customers, (2) inform customers and DER developers where saturated circuits are located, and (3) inform the planning process and identify circuit constraints to be solved to expand DER growth.")

34 NY Public Service Commission, Dkt. 16-M-0411, In the Matter of Distributed System Implementation Plans; NY Public Service Commission, Dkt. 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

35 The Joint Utilities include: Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation, all investor owned utilities.

36 New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 49 (Nov. 1, 2016) ("SDSIP").

37 NY Public Service Commission, Case 16-M-0411, Order on Distributed System Implementation Plan Filings, pp. 10-15 (Mar. 9, 2017).

38 MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 5 (Aug. 1, 2017).

39 Minn. Stat. § 216B.2425, subd. 8.

40 Xcel Energy, Dkt. E002/M-15-962, Distribution System Study: Distribution Grid Modernization Report, p. 13 (Dec. 1, 2016) ("Xcel Distribution System Study") (noting that the initial hosting capacity results are "not intended to be used for approving interconnection requests at this time").

41 MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 5 (Aug. 1, 2017).

42 *Id.*

43 Xcel Energy, Dkt. E002/M-17-777, Distribution System/Hosting Capacity Study, p. 17-20 (Nov. 1, 2017).

44 *See* Herman K. Trabish, *How Utility Data Sharing is Helping the New York REV Build the Grid of the Future*, Utility Dive (Feb. 8, 2017), http://www.utilitydive.com/news/how-utility-data-sharing-is-helping-the-new-york-rev-build-the-grid-of-the/434972/ ("Currently, only utilities have full access to the data needed to fully understand the [distribution] system's limits and potential, and even they often lack visibility to understand exactly where all their assets are located.").

45 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy Economy (Aug. 11, 2015), http://blog.aee.net/understanding-irps-how-utilities-plan-for-the-future ("Historically, utilities mainly considered generation, transmission, and distribution additions to meet growing demand.").

46 *See* Krysti Shallenberger, *The Top 5 States for Utility Grid Modernization and Business Model Reform* (Apr. 3, 2017), http://www.utilitydive.com/news/the-top-5-states-for-utility-grid-modernization-and-business-model-reform/439550/ (discussing grid modernization activities in California, New York, Minnesota, Massachusetts, and Rhode Island, as well as developments in other states).

47 *See, e.g.*, NY Public Service Commission, Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance, p. 2 (Apr. 20, 2016) ("At the core of the new model is improved information—improved both in its granularity, temporal and spatial, and in its accessibility to consumers and market participants."); Cal. Public Utilities Commission, R.14-08-013, Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769—Distribution Resource Planning, p. 5 (Feb. 6, 2015) ("Each iteration of the process will move California further down a path toward deeper penetration of DER, more effective analysis of where DER provides the most value to customers and to the electric distribution system, and a greater understanding of the policy framework that is necessary to achieve these goals.").

48 IDP Concept Paper at p. 10.

49 *See* SDSIP at pp. 28-29 (discussing role of HCA in competitive solicitation of non-wires alternatives).

50 Hawaiian Electric Companies, Initial Statement of Position on Deferred Issues and Technical Track, Issues, Exhibit C, Circuit Hosting Capacity Analysis: Benefits and Future Improvements, p. 4 (Aug. 2017) ("Finally, the hosting capacity analysis helps distribution planners to identify congested circuits and find solutions to integrate high forecasted levels of DER. Once current and near-term circuit constraints are identified, planners can find potential solutions for solving those constraints — whether the solution is a low-cost utility-side adjustment, a customer solution (i.e., advanced inverter), or a traditional circuit upgrade.").

51 *Id.*; Solar City IDP at pp. 7-8

52 ICF IDP at p. 4.

53 *See id.* at p. 9 ("A better approach [than using singular deterministic forecasts] is to use multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs.")

54 *See*, More Than Smart, *Integration Capacity Analysis Working Group - Group I Interim Status Report*, p. 2 (Aug. 31, 2017), http://drpwg.org/wp-content/uploads/2016/07/ICA-Group-I-interim-status-report-final.pdf

55 See SDSIP at p. 55 ("An evolution to this more detailed hosting capacity analysis [in Stage 3] will enable planners to more specifically identify locations along a feeder with higher levels of hosting capacity and determine how sub-feeder-level hosting capacity is impacted by current and prospective DER interconnections on the system.").

56 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, p. 9 ("The WG determined that there is a role for a planning use case for the ICA, as it may be possible that the ICA can help determine and guide where and when future integration capacity is a limitation, among other possible planning uses. . . However, many components of this use case remain undefined, due to multiple ongoing efforts in other CPUC proceedings that will inform how ICA will be used in system planning, as well as the need for further clarity into the utility annual planning process itself.").

57 Southern California Edison, R. 14-08-013, Southern California Edison Company's (U338-E) Update Demonstration Projects A and B Final Reports, Appendix B (Locational Net Benefit Analysis Final Report), p. 2 (Jan. 4, 2017) ("SCE Final Report B").

58 *Id.*; ICF IDP at p. 16.

59 ICF IDP at p. 16

60 *Id.* ("[T]he value of DER on the distribution system is locational in nature—that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components.").

61 *Id.* ("The cost estimates of [planned infrastructure] investments form the potential value that may be met by sourcing services from qualified DERs as non-wires alternatives.").

62 *Id.*

63 Bebon, Joseph, *Solar Groups Speak Out Against Recent NY Ruling*, Solar Industry Magazine (Sept. 18, 2017), https://solarindustrymag.com/solar-groups-speak-latest-n-y-ruling.

64 Cal. Public Utilities Commission, R.14-08-013, Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization, Attachment (Staff White Paper on Grid Modernization), pp. 20, 22 (May 16, 2017) ("Grid Modernization White Paper") (setting forth development of LBNA, as well as a Grids Needs Assessment based on LNBA and ICA results, in Staff's proposed Grid Modernization process for California investor owned utilities); see also LNBA Working Group reports, California's Distribution Resources Plan, R. 14-08-013, http://drpwg.org/sample-page/drp/.

65 Cal. Public Utilities Commission, R.14-08-013, Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework, Attachment A (Energy Division Staff Proposal on a Distribution Investment Deferral Framework), pp. 11-13 (June 30, 2017) ("Distribution Investment Deferral Framework").

66 *Id.* at pp. 29-30.

67 Grid Modernization White Paper at pp. 23-24.

68 NY Public Service Commission, Case 15-E-0751, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, p. 5 (Sept. 14, 2017).

69 SDG&E Final Report A at p. 31.

70 *Id.* at pp. 19, 33, 49.

71 *See* Pepco Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning Control and Analysis*, pp. 7-8 (Dec. 14, 2015); EPRI, *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012).

72 *See* Xcel Distribution System Study at pp. 3-4; SDSIP at p. 52.

73 *See*, e.g. EPRI Integration at 7.

74 SDSIP at p. 49.

75 SDSIP at p. 52; Xcel Distribution System Study at p. 11.

76 PG&E Final Report A at p. 16.

77 *Id.* at p. 17.

78 *See* NY Public Service Commission, Case 16-M-0411, Order on Distributed System Implementation Plan Filings, pp. 10-15 (Mar. 9, 2017); Xcel Distribution System Study at pp. 3-4, 6 (focusing HCA analysis on small-scale distributed generation technologies); Xcel Energy, Dkt. E002/M-15-962, Supplemental Comments: Biennial Distribution Grid Modernization Report, pp. 9, 11 (Mar. 20, 2017) (explaining that "energy storage load characteristics were excluded from [Xcel's HCA] analysis" and excluding demand response and energy efficiency technologies from Xcel's definition of DER); Pepco Analysis (discussing only PV penetration).

79 See Xcel Distribution System Study at pp. 10-12; SDG&E Final Report A at p. 39 (regarding use of a heuristic approach to evaluate the operational flexibility criterion); Pacific Gas & Electric Co., R. 14-08-013, Demonstration A—Enhanced Integration Capacity Analysis: PG&E ICA Demo A Interim Report, p. 7 (Sept. 30, 2015) ("In order to ensure transparency and consistency within the methodology, the various assumptions and starting point parameters must be expressed" so that, for instance, results can be replicated by third parties.).

80 SDG&E Final Report A at p. 79.

81 PG&E Final Report A at p. 116.

82 See EPRI Integration at p. 7.

83 PG&E's PV RAM maps, for instance, "employ a coloring scheme that depicts the capacity level of a line section by a color gradient to better display the varying levels of capacity by location on each feeder. This coloring scheme is intended to help DER developers and customers better understand where on a circuit location of a DER is better suited." PG&E Final Report at p. 118. PG&E's RAM maps are available at https://www.pge.com/en_US/for-our-business-partners/energy-supply/solar-photovoltaic-and-renewable-auction-mechanism-program-map/solar-photovoltaic-and-renewable-auction-mechanism-program-map.page; Central Hudson's Hosting Capacity Map is available at https://www.cenhud.com/dg/dg_hostingcapacity ("Each distribution circuit is color coded based on its maximum hosting capacity value."); Pepco Holding LLC's Hosting Capacity Map is available at http://www.pepco.com/Hosting-Capacity-Map.aspx.

84 *See RESTful API*, SearchCloudStorage.com, http://searchcloudstorage.techtarget.com/definition/RESTful-API ("A RESTful API is an application program interface (API) that uses HTTP requests to GET, PUT, POST and DELETE data.").

85 Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, p. 5 (Mar. 15, 2017).

86 Interstate Renewable Energy Council, Case 16-M-0411, Comments of the Interstate Renewable Energy Council, Inc. on the Supplemental Distributed System Implementation Plan, p. 11 (Jan. 9, 2017).

87 *Id.*

88 Cal. Public Utilities Commission, R. 14-08-013, Decision on Track 1 Demonstration Projects, pp. 58-61 (Oct, 6, 2017).

89 Cal. Public Utilities Code § 769; *see also* Cal. Assembly Bill 327 (Perea 2013).

90 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling on Guidance For Public Utilities Code Section 769—Distribution Resource Planning, Attachment, at pp. 3-4 (Feb. 6, 2015).

91 *Id.*

92 *Id.* at p. 4 (Ordering the utilities to: "Specify recommendations for utilizing the Integration Capacity Analysis to support planning and streamlining of Rule 21 for distributed generation and Rule 15 and Rule 16 assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.").

93 *See* California ICA Working Group materials, California's Distribution Resources Plan, R. 14-08-013, http://drpwg.org/sample-page/drp/ and http://drpwg.org/archive-ica-and-lnba-working-group/.

94 See Joint Motion of San Diego Gas & Electric Company (U 902 E), Southern California Edison Company (U 338 E), and Pacific Gas and Electric Company (U 39 E), R.14-08-013 (June 9, 2016) (seeking permission to perform a test of both methodologies as part of the demonstration project); Cal. Public Utilities Commission, R. 14-08-013, Email Ruling of Administrative Law Judge Mason (June 10, 2016) (authorizing the utilities to do a comparison of both methodologies in their Demonstration projects).

95 Cal. Public Utilities Commission, R. 14-08-013, Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016).

96 PG&E Final Report A at p. 53.

97 PG&E Final Report A at p. 98 ("In general, the streamlined approach focused on speed and abstraction of analysis across components while the iterative is focused on detail and precision of power flow results closer to what may be seen in an interconnection study.").

98 SDG&E Final Report A at p. 45.

99 Southern California Edison, R. 14-08-013, Southern California Edison Company's (U 338-E) Update Demonstration Projects A and B Final Reports, Appendix A (Enhanced Integration Capacity Analysis Final Report), p. 80 (Jan. 4, 2017) ("SCE Final Report A"); PG&E Final Report A at p. 105.

100 SCE Final Report A at pp. 45, 47.

101 PG&E Final Report A at pp. 96, 143.

102 PG&E Final Report A at p. 11 ("The streamlined techniques are better suited to more appropriately analyze large amounts of scenarios for planning purpose, while the iterative is better suited for analyzing circuit conditions for specific interconnection purposes"); SDG&E Final Report A at p. 9; SCE Final Report A at pp. 2-3.

103 SDG&E Final Report A at p. 9; PG&E Final Report A at 155.

104 PG&E found that the iterative methodology was better suited for interconnection, while streamlined was better suited for planning purposes. PG&E proposed using the streamlined method for the mapping and then recommended the iterative results be applied when actually processing interconnection applications for software efficiency reasons. The ICA working group found this approach unworkable because it wanted ICA maps to accurately reflect the results an applicant could expect from the interconnection process. Cal. Public Utilities Commission, R. 14-08-013, Integration Capacity Analysis Working Group Final Report, pp. 12-14 (Mar. 15, 2017).

105 Cal. Public Utilities Commission, R.14-08-013, Decision on Track 1 Demonstration Projects, pp. 29-33.

106 For information on the ongoing ICA Working Group discussions regarding the planning use case see http://drpwg.org/sample-page/drp/.

107 For more about Reforming the Energy Vision, visit http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument.

108 NY Public Services Commission, Case 14-M-0101, Order Adopting Distributed System Implementation Plan Guidance, pp. 43-46 (Apr. 20, 2016).

109 *Id.* at pp. 19-22.

110 The Joint Utilities are comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

111 EPRI, Defining a Roadmap.

112 *Id.* at p. 4.

113 SDSIP at p. 52; see also EPRI Integration.

114 To date there has been no published analysis that compares exactly how the "streamlined" method tested in California compares with the current version of the DRIVE tool. However, PG&E stated in their distributed resources plan that it's "approach is similar to the Electric Power and Research Institute (EPRI) streamlined hosting capacity for PV Interconnection." Pacific Gas and Electric Co., R. 14-08-013, *Electric Distribution Resources Plan*, p. 23 (July 1, 2015). EPRI has yet to publish any public information that details the methodology used to support the DRIVE tool (though this information may be available to paying members) nor has there been an objective analysis done that analyzes the accuracy of the results produced by the DRIVE tool.

115 SDSIP at p. 48.

116 *Id.* at 49.

117 NY Public Service Commission, Cases 14-M-0101, 16-M-0411, Order on Distributed System Implementation Plan Filings, p. 11 (Mar. 9, 2017) ("Hosting capacity ranges are based on the circuit characteristics and assume that there are no DERs interconnected. Therefore, the maps will have pop-up boxes that display the DER s currently interconnected and DER projects that are in the interconnection queue process.").

118 *Id.* at p. 12 ("Hosting capacity was one of the most frequent topics discussed in the comments. Commenters on the Initial DSIPs generally noted that the information currently provided by the Utilities is insufficient and that more data related to hosting capacity is needed.").

119 *Id.* at p. 14.

120 *Id.* at pp. 14-15.

121 The directive came in the form of amendments to Minnesota's transmission-planning statute, Minn. Stat § 216B.2425, and required covered utilities "to conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and . . . identify necessary distribution upgrades to support the continued development of distributed generation resources." Minn. Stat. § 216B.2425, subd. 8.

122 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Certifying Advanced Distribution-Management System (ADMS) Project Under Minn. Stat. § 216B.2425 and Requiring Distribution Study (June 28, 2016).

123 MN Public Utilities Commission, Dkt. E002/M-15-962, In the Matter of Northern States Power Company's 2015 Biennial Distribution Grid Modernization Report (Dec. 1, 2016).

124 *Id.* at p. 11.

125 *Id.*

126 *Id.* at Attachment A.

127 MN Public Utilities Commission, Dkt. E002/M-15-962, Information Request PUC #1 (Feb. 21, 2017).

128 MN Public Utilities Commission, Dkt. E002/M-15-962, Notice of Comment Period on Distribution System Study (Feb. 21, 2017).

129 MN Public Utilities Commission, Notice of Commission Meeting (June 2, 2017) (providing notice that the PUC would consider action on Xcel's initial hosting capacity report at its June 15, 2017 hearing).

130 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report (Aug. 1, 2017).

131 *Id.* at p. 5.

132 *Id.* at p. 6.

133 *Id.*

134 Xcel Energy, Dkt. E002/M-17-777, Distribution System/Hosting Capacity Study (Nov. 1, 2017).

135 *Id.* at p. 1-4.

136 MN Public Utilities Commission, Dkt. E999/CI-15-556, Notice of Comment Period on Distribution System Planning Efforts and Considerations (Apr. 21, 2017).

137 *Id.*

138 MN Public Utilities Commission, Dkt. E002/M-15-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, p. 6 (Aug. 1, 2017).

139 Xcel Energy, Dkt. E002/M-17-777, *Distribution System/Hosting Capacity Study* (Nov. 1, 2017).

140 MN PUC, Dkt. E002/M-17-777, *Notice of Comment Period on Xcel's 2017 Distribution System Hosting Capacity Report* (Nov. 15, 2017).

141 See, e.g., Dkt. E999/CI-15-556, Comments of Interstate Renewable Energy Council, Inc. on Distribution System Planning Efforts and Considerations, pp. 12-14 (Aug. 21, 2017); Dkt. E999/CI-15-556, Comments of the Advanced Energy Economy Institute on Distribution System Planning, p. 5 (July 20, 2017).

142 Xcel Distribution System Study, pp. 6, 10-11; Dkt. E002/M-15-962, Xcel Energy Supplemental Comments on Biennial Distribution Grid Modernization Report, pp. 2-3 (Mar. 20, 2017).

143 *See*, e.g., Dkt. E002/M-15-962, Comments of the Interstate Energy Renewable Energy Council, Inc. Regarding Xcel Energy's Hosting Capacity Analysis and Supplemental Comments, pp. 16-19 (Apr. 20, 2017); Dkt. E002/M-15-962, Comments by Fresh Energy in Response to the Commission's February 2017 Notice, pp. 1-3 (Apr. 20, 2017); MN Public Utilities Commission, Dkt. E002/M-14-962, Order Setting Additional Requirements for Xcel's 2017 Hosting Capacity Report, pp. 3-4 (Aug. 1, 2017) (summarizing stakeholders' positions).

144 Pepco Holdings, Inc., *Model-Based Integrated High Penetration Renewables Planning Control and Analysis*, pp. 7-10 (Dec. 14, 2015) ("Pepco Analysis"); see also *EPRI, Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV* (Dec. 2012).

145 Pepco Analysis at p. 11.

146 Pepco Holdings LLC, *Interconnection of Distributed Energy Resources*, § 2.6 (Jun. 21, 2016), http://www.pepco.com/uploadedFiles/wwwpepcocom/Content/Page_Content/GPC/PHI%20Interconnection%20of%20Distributed%20Energy%20Resources.pdf.

147 *Id.*

148 Pepco Holdings LLC, Restricted Circuit Map, http://www.pepco.com/Restricted-Circuit-Map.aspx.

149 See Pepco Holdings LLC, Criteria Limits for Distributed Energy Resource Connections to the ACE, DPL and Pepco Distributions Systems (Less than 69KV), http://www.pepco.com/library/templates/Interior.aspx?Pageid=6442460710&LangType=1033

150 Pepco Analysis at pp. 12-16.

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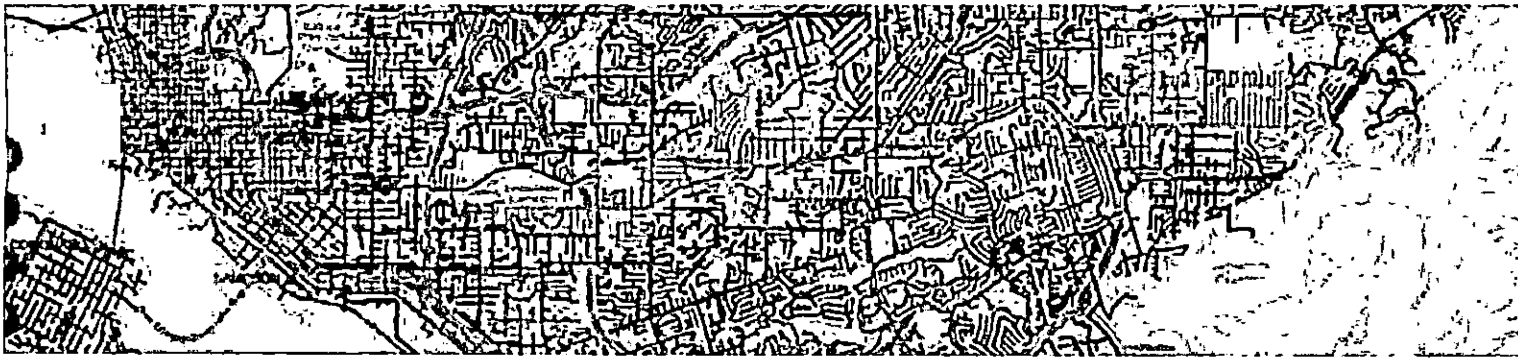

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