COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SUR-CREDIT	)))))))))	**CASE NO. 2020-00350**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
COMMISSION STAFF'S SEVENTH REQUEST FOR INFORMATION
DATED JULY 22, 2021

FILED: AUGUST 2, 2021

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of August 2021.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Transmission for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Elizabeth J. McFarland

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of July 2021.

Kimberly C Brock (SEAL)

Notary Public

Notary Public, ID No. KYNP14646

My Commission Expires:

10-16-2020

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Eileen L. Saunders**, being duly sworn, deposes and says that she is Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Eileen L Saunders
Eileen L. Saunders

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29 day of July 2021.

Danielle L. Vincent
Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

June 25, 2025

VERIFICATION

STATE OF NORTH CAROLINA)
)
COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, and that he has personal knowledge of the matters set forth in the responses for which he is identified ~~as the~~ witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30 day of July 2021.

Adam Curry (SEAL)
Notary Public

Notary Public ID No. 20210850012

My Commission Expires:
03/02/2026

Adam Curry
Notary Public
Buncombe County, NC
Notary ID# 20210050012
Commission Expires: 03/02/2026

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of August 2021.

Notary Public

Notary Public ID No. KYNP32193

My Commission Expires:

06-25-2025

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of July 2021.

Notary Public

Notary Public ID No. **603967**

My Commission Expires:

July 11, 2022

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 1

Responding Witness: David S. Sinclair

Q-1. Refer to LG&E's response to Commission Staff's Third Request for Information, Item 19b., which states that the primary components in the determination of hourly marginal costs were incremental heat rates, fuel prices, variable O&M, and purchased power costs. Indicate whether these components were included in the determination of the revised avoided energy costs shown in Supplemental Exhibit DSS3, Recommended LQF and SQF Rates.

A-1. Confirmed. The same costs were included in both analyses.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 2

Responding Witness: Eileen L. Saunders

Q-2. Refer to LG&E's response to Commission Staff's Post-Hearing Request for Information, Item 28, regarding the transfer, closing, or opening of an account.

a. Explain why an account would be closed and a new account established when service is transferring to someone who already lives at the address but whose name is just not listed on the account or not listed as financially responsible for the account.

b. Indicate whether an account would still be closed and a new account established if an individual were able to prove by whatever means necessary that they were already residing at the address with the previous primary account holder.

c. Explain the conditions or requirements a new primary account holder would have to meet prior to having electric/gas service placed into their name in instances where the individual already resides at the address but is not listed on the account or listed as financially responsible for the account.

d. Explain the conditions or requirements a new primary account holder would have to meet prior to having electric/gas service placed into their name in instances where the individual does not already reside at the address.

e. Provide the personal information requested of each new potential customer, explain why each item is needed, and for each one, indicate whether the information is required in order to process the application or whether it is optional for the customer to provide.

A-2.

a. All adults living in a residence are supposed to be included on an application for service to have an account with the Company. In accordance with the Transfer of Application section of the Company's Terms and Conditions, applications for electric service are not transferable.[1] Therefore, when one or

[1] Louisville Gas and Electric Company, P.S.C. Electric No. 13, Original Sheet No. 97.

more of the adults on an account ceases to reside at the residence for any reason (including death or divorce), the adult(s) still living at the residence must submit a new application for service. Moreover, if any of the adults on the new application resided at the residence prior to the new application and there is a balance owing on the previous account, the Company will refuse service until the previous balance is paid. This helps ensure that adult residents cannot effectively avoid responsibility for utility service from which they benefit, and it helps ensure that adults who no longer live at a residence are not held responsible for utility service from which they did not benefit.

b. Yes, an account would still be closed and a new account established in the circumstance described in the request.

c. In accordance with the Application for Service section of the Company's Terms and Conditions,[2] a new application for service may require the following:
   - Full legal name
   - Personal identifier (full social security number or other taxpayer identification number, date of birth if applicable)
   - Relationship of the applying party to the party desiring service
   - Address
   - Previous service address, if any
   - Move in date (provide documentation such as lease, rental agreement or deed, as needed)
   - Other responsible adults living at the address
   - Credit check to determine deposit waiver or consent to bill deposit
   - Any other information Company deems necessary for legal, business or debt-collection purposes
   - Payment of any outstanding balance on the previous account if the applicant was a resident at the service address for which the applicant is seeking service

d. See the response to part c.

e. See the response to part c. The items are needed to ensure the Company can identify the applicant(s), set an appropriate deposit amount, collect outstanding balances (if any), and otherwise provide service. The items the Company requests are not optional.

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[2] Louisville Gas and Electric Company, P.S.C. Electric No. 13, Original Sheet No. 97.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 3

Responding Witness: Robert M. Conroy / David S. Sinclair

Q-3. Refer to the Supplemental Testimony of Robert M. Conroy (Supplemental Conroy Testimony), page 11, lines 12–17, discussing setting the capacity rate to zero when a total of 1,000 MW of nameplate QF capacity is contracted across LG&E and Kentucky Utilities Company (KU).

a. Provide the current amount of nameplate QF capacity on each system.

b. Explain why the capacity rate should be zero when KU and LG&E have 1,000 MW of nameplate QF capacity.

A-3.

a. The current amount of SQF/LQF capacity as of July 26, 2021 is shown below.

Company	Type	SQF/LQF	Connected Capacity (kW)	Storage Capacity (kW)	Total Capacity (kW)
KU	Solar	LQF	2,162	0	2,162
		SQF	681	0	681
KU Total			**2,842**	**0**	**2,842**
LGE	Solar	LQF	1,720	30	1,750
		SQF	73	0	73
LGE Total			**1,794**	**30**	**1,824**
TOTAL			**4,636**	**30**	**4,666**

b. See Mr. Sinclair's Supplemental Direct Testimony from line 17 on page 13 through line 8 on page 15. The Companies are proposing for now to cap the amount of QF capacity eligible for a capacity payment at 1,000 MW. Therefore, the capacity payment for QF capacity added after the first 1,000 MW is zero. The analysis that provides the basis for the 1,000 MW cap is summarized in the response to Question No. 24.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 4

Responding Witness: David S. Sinclair

Q-4. Refer to the Supplemental Conroy Testimony, Exhibit RMC-4, page 2 of 5. Explain how the capacity rate limit MW amounts of 109 MW and 891 MW were derived.

A-4. The MW amounts of 109 MW and 891 MW were preliminary figures and should have been revised with the final figures of 100 MW and 900 MW. As explained in Mr. Sinclair's supplemental testimony, the 100 MW figure is the average of the capacity need in 2028 under two scenarios: (1) Mill Creek Unit 2 and Brown Unit 3 retire in 2028, resulting in a 199 MW capacity need in 2028 and (2) Mill Creek Unit 2 and Brown Unit 3 retire according to their book depreciation life, resulting in no capacity need in 2028. The average of 199 MW and zero is the 100 MW average need in 2028. 900 MW is the difference between the proposed 1,000 MW of QF capacity eligible for a capacity payment and 100 MW.

LOUISVILLE GAS AND ELECRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 5

Responding Witness: Robert M. Conroy

Q-5. Refer to the Supplemental Conroy Testimony, Exhibits RMC-4 and RMC-6. Provide a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

A-5. See attached.

Louisville Gas and Electric Company

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a "qualifying facility" as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called "Seller") with a nameplate capacity of 100 kW or less ~~only from the owner of qualifying cogeneration or small power production facilities of 100 kW or less (such owner being hereafter called "Seller") installed on Seller's property to provide all or part of its requirements of electrical energy, or from which facilities Seller may elect to sell to Company all or part of such output of electrical energy~~. D/N D/N D/N

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation. D/N D/N

Company will purchase such energy or energy and capacity from Seller at the rates ~~at the Rate, A or B,~~ set out below ~~and selected as hereafter provided,~~ and under the terms and conditions stated herein. ~~Company reserves the right to change the said Rates, upon proper filing with and acceptance by the jurisdictional Commission.~~ D/N D/N D/N

D/N

Seller may choose to (a) enter into a power purchase agreement ("PPA") with Company for sales of energy or energy and capacity from Seller or (b) sell energy to Company on an as-available basis.

DEFINITIONS

"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Technology	$/MWh
Solar: Single-Axis Tracking	22.94
Solar: Fixed Tilt	23.19
Wind	22.51
Other Technologies	22.04

DATE OF ISSUE: ~~July 20, 2021~~

DATE EFFECTIVE: With ~~Service~~ Bills Rendered
On and After September DD, 2021 ~~June 30, 2020~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

~~**RATE A: TIME-DIFFERENTIATED RATE**~~

~~1. For summer billing months of June, July, August and September (on-peak hours)~~	~~$0.02282 per kWh~~
~~2. For winter billing months of December, January and February (on-peak hours)~~	~~$0.02236 per kWh~~
~~3. During all other hours (off-peak hours)~~	~~$0.02145 per kWh~~

~~On-peak hours for summer billing months of June through September are defined as weekdays (exclusive of holidays) from 8:01 A.M. to 9:00 P.M., Eastern Standard Time (under 1 above).~~

~~On-peak hours for winter billing months of December through February are defined as weekdays (exclusive of holidays) from 6:01 A.M. to 9:00 P.M., Eastern Standard Time (under 2 above).~~

~~Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above).~~

~~Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.~~

~~**RATE B: NON-TIME-DIFFERENTIATED RATE**~~

~~For all kWh purchased by Company~~	~~$0.02173 per kWh~~

DATE OF ISSUE: ~~July 20, 2021~~

DATE EFFECTIVE: With ~~Service~~ Bills Rendered
On and After September DD, 2021~~June 30, 2020~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020-00350 dated XXXX

RATES FOR PURCHASES FROM SELLER UNDER PPA

D/N

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

When the total qualifying facility nameplate capacity contracted by Company and its sister utility, Louisville Gas and Electric Company, reaches 1,000 MW, the capacity rate for all subsequent qualifying facility contracts will be zero. This limitation will be reviewed and possibly revised as part of Company's biennial avoided cost filing review process with the Commission.

T/D

~~SELECTION OF RATE AND METERING~~

~~Subject to provisions hereafter in this Section relative to payment of costs of metering equipment, either Seller or Company may select Rate A, the Time-Differentiated Rate, for application to Company's said purchases of energy from Seller. If neither Seller nor Company selects Rate A, then Rate B, the Non-Time-Differentiated Rate, shall apply.~~

~~If neither Seller nor Company selects Rate A, and Rate B therefore is to apply to such purchases, Company, at Seller's cost, will install, own and operate a non-time-differentiated meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system. Such meter will be tested at intervals prescribed by Commission Regulation, with Seller having a right to witness all such tests; and Seller will pay to Company its fixed cost on such meter and equipment, expense of such periodic tests of the meter and any other expenses (all such costs and expenses, together, being hereafter called "costs of non-time-differentiated metering").~~

~~If either Seller or Company selects Rate A to apply to Company's said purchases of energy from Seller, the party (Seller or Company) so selecting Rate A shall pay (a) the cost of a time-differentiated recording meter and associated equipment, at a location selected by Company, measuring energy, produced by Seller's generator, flowing into Company's system, required for the application of Rate A, in excess of (b) the costs of non-time-differentiated metering which shall continue to be paid by Seller.~~

~~In addition to metering referred to above, Company at its option and cost may install, own and operate, on Seller's generator, a recording meter to record the capacity, energy and reactive output of such generator at specified time intervals.~~

~~Company shall have access to all such meters at reasonable times during Seller's normal business hours, and shall regularly provide to Seller copies of all information provided by such meters.~~

~~PAYMENT~~

~~Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a Customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as Customer.~~

~~PARALLEL OPERATION~~

~~Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:~~

PAYMENT T

Any payment due from Company to Seller will be due within sixteen (16) business days (no less than twenty-two (22) calendar days) from date of Company's reading of meter; provided, however, that, if Seller is a Customer of Company, in lieu of such payment Company may offset its payment due to Seller hereunder, against Seller's next bill and payment due to Company for Company's service to Seller as Customer. T

TERM OF CONTRACT N

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 20-year PPA with Company for such purchases. Regarding energy purchases under a 20-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 20-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase. N

PARALLEL OPERATION T

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise: T

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1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the inter-connection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system.

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof.

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, ~~-~~where Seller is not a Customer of Company. When Seller is a Customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation,

T

or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case.

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof.
7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.
8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.
9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.
10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

Louisville Gas and Electric Company

Standard Rate Rider **LQF**

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

This rate and the terms and conditions set out herein are available for and applicable to Company's purchases of energy or energy and capacity from the owner of a "qualifying facility" as defined in 807 KAR 5:054 Section 1(8) (such owner being hereafter called "Seller") with a nameplate capacity greater than 100 kW. D/N

Company will permit Seller's generating facilities to operate in parallel with Company's system under conditions set out below under Parallel Operation.

Company will purchase such energy or energy and capacity from Seller at the rates set out below and under the terms and conditions stated herein.

Seller may choose to (a) enter into a power purchase agreement ("PPA") with Company for sales of energy or energy and capacity from Seller or (b) sell energy to Company on an as-available basis.

RATES HEREIN ARE ADVISORY

Pursuant to 807 KAR 5:054 Section 7(4), the rates set forth herein are solely the basis for negotiating final purchase rates with Seller.

DEFINITIONS

"As-available" describes energy purchases from Seller when Seller has not entered into a PPA with Company.

"Other Technologies" means all electric power generating technologies encompassed in the definition of "qualifying facility" in 807 KAR 5:054 Section 1(8) other than solar and wind.

RATES FOR ENERGY PURCHASES FROM SELLER ON AN AS-AVAILABLE BASIS

Technology	$/MWh
Solar: Single-Axis Tracking	22.94
Solar: Fixed Tilt	23.19
Wind	22.51
Other Technologies	22.04

~~Available to any small power production or cogeneration "qualifying facility" with capacity over 100 kW as defined by the Kentucky Public Service Commission Regulation 807 KAR 5:054, and which contracts to sell energy or capacity or both to Company.~~

~~**RATES FOR PURCHASES FROM QUALIFYING FACILITIES**~~

DATE OF ISSUE: ~~July 20, 2021~~

DATE EFFECTIVE: With Bills Rendered
On and After September DD, 2021~~May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020~~18~~-00350~~295~~ dated XXXX~~April 30, 2019~~

~~**Energy Component Payments**~~

~~The hourly avoided energy cost (AEC) in $ per MWh, which is payable to a QF for delivery of energy, shall be equal to Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month. The total amount of the avoided energy cost payment to be made to a QF in an hour is equal to [AEC x E_{QF}], where E_{QF} is the amount of megawatt-hours delivered by a QF in that hour and which are determined by suitable metering.~~ D/N

~~**Capacity Component Payments**~~

~~The hourly avoided capacity cost (ACC) in $ per MWh, which is payable to a QF for delivery of capacity, shall be equal to the effective purchase price for power available to Company from the inter-utility market (which includes both energy and capacity charges) less Company's actual variable fuel expense (AEC). The total amount of the avoided capacity cost payment to be made to a QF in an hour is equal to [ACC x CAP_i], where CAP_i, the capacity delivered by the QF, is determined on the basis of the system demand (D_i) and Company's need for capacity in that hour to adequately serve the load.~~

~~**Determination of CAP_i**~~

~~For the following determination of CAP_i, $C_{LG\&E}$ represents Company's installed or previously arranged capacity at the time a QF signs a contract to deliver capacity; C_{QF} represents the actual capacity provided by a QF, but no more than the contracted capacity; and C_M represents capacity purchased from the inter-utility market.~~

DATE OF ISSUE: ~~July 20, 2021~~

DATE EFFECTIVE: With Bills Rendered
On and After September DD, 2021~~May 1, 2019~~

ISSUED BY: /s/ Robert M. Conroy, Vice President
State Regulation and Rates
Louisville, Kentucky

Issued by Authority of an Order of the Public Service Commission in Case No. 2020~~18~~-00350~~295~~ dated XXXX~~April 30, 2019~~

Louisville Gas and Electric Company

P.S.C. Electric No. 13, Original Sheet No. 56.1

Standard Rate Rider LQF
Large Capacity Cogeneration and Small Power Production Qualifying Facilities

RATES FOR PURCHASES FROM SELLER UNDER PPA

D/N

Energy Rates ($/MWh)

Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	22.94	23.85	23.92	24.03	24.14	24.26
Solar: Fixed Tilt	23.19	24.07	24.14	24.26	24.36	24.48
Wind	22.51	23.71	23.83	23.97	24.11	24.24
Other Technologies	22.04	22.98	23.07	23.18	23.29	23.39

Capacity Rates ($/MWh)

Capacity Rates for First 109 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71

Capacity Rates for Next 891 MW of Contracted Nameplate Qualifying Facility Capacity						
Technology	2-Year PPA (2021-2023)	20-Year Level Rate for Contract Purchases Beginning: 2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

When the total qualifying facility nameplate capacity contracted by Company and its sister utility, Louisville Gas and Electric Company, reaches 1,000 MW, the capacity rate for all subsequent qualifying facility contracts will be zero. This limitation will be reviewed and possibly revised as part of Company's biennial avoided cost filing review process with the Commission.

T

DATE OF ISSUE: ~~July 20, 2021~~

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On and After September DD, 2021~~May 1, 2019~~

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State Regulation and Rates
Louisville, Kentucky

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Large Capacity Cogeneration and Small Power Production Qualifying Facilities

~~1. System demand is less than or equal to Company's capacity:~~

~~$D_1 \leq C_{LG\&E}$; $CAP_i = 0$~~ T

T

~~2. System demand is greater than Company's capacity but less than or equal to the total of Company's capacity and the capacity provided by a QF:~~ T T T

~~$C_{LG\&E} < D_i \leq [C_{LG\&E} + C_{QF}]$; $CAP_i = C_M$~~ T

~~3. System demand is greater than the total of Company's capacity and the capacity provided by a QF:~~ D/N D/N D/N

~~$D_i > [C_{LG\&E} + C_{QF}]$; $CAP_i = C_{QF}$~~ N

N

PAYMENT

Company shall pay each bill for electric power rendered to it in accordance with the terms of the contract, within sixteen (16) business days (no less than twenty-two (22) calendar days) of the date the bill is rendered. In lieu of such payment plan, Company will, upon written request, credit Customer's account for such purchases. D/N

TERM OF CONTRACT

If Seller desires Company to purchase energy and capacity from Seller, Seller must enter into a either a 2-year PPA or a 20-year PPA with Company for such purchases. Regarding energy purchases under a 20-year PPA, the PPA will specify whether Seller desires to receive (a) the applicable fixed 20-year level energy rate or (b) the applicable as-available energy rate in effect at the time of each purchase~~For contracts which cover the purchase of energy only, the term shall be one (1) year, and shall be self-renewing from year-to-year thereafter, unless canceled by either party on one (1) year's written notice.~~

~~For contracts which cover the purchase of capacity and energy, the term shall be five (5) years~~.

~~**TERMS AND CONDITIONS**~~

~~1. Qualifying facilities shall be required to pay for any additional interconnection costs, to the extent that such costs are in excess of those that Company would have incurred if the qualifying facility's output had not been purchased.~~

~~2. A qualifying facility operating in parallel with Company must demonstrate that its equipment is designed, installed, and operated in a manner that insures safe and reliable interconnected operation. A qualifying facility should contact Company for assistance in this regard.~~

~~3. The purchasing, supplying and billing for service, and all conditions applying hereto, shall be specified in the contract executed by the parties, and are subject to the jurisdiction of the Kentucky Public Service Commission, and to Company's Terms and Conditions currently in effect, as filed with the Commission.~~

PARALLEL OPERATION

Company hereby permits Seller to operate its generating facilities in parallel with Company's system, under the following conditions and any other conditions required by Company where unusual conditions not covered herein arise:

1. Prior to installation in Seller's system of any generator and associated facilities which are intended to be interconnected and operated in parallel with Company's system, or prior to the interconnection to Company's system of any such generator and associated facilities already installed in Seller's system, Seller will provide to Company plans for such generator and facilities. Company may, but shall have no obligation to, examine such plans and disapprove them in whole or in part, to the extent Company believes that such plans and proposed facilities will not adequately assure the safety of Company's facilities or system. Seller acknowledges and agrees that the sole purpose of any Company examination of such plans is the satisfaction of Company's interest in the safety of Company's own facilities and system, and that Company shall have no responsibility of any kind to Seller or to any other party in connection with any such examination. If Seller thereafter proposes any change from such plans submitted to Company, prior to the implementation thereof Seller will provide to Company new plans setting out such proposed change(s).

2. Seller will own, install, operate and maintain all generating facilities on its plant site, such facilities to include, but not be limited to, (a) protective equipment between the systems of Seller and Company and (b) necessary control equipment to synchronize frequency and voltage between such two systems. Seller's voltage at the point of interconnection will be the same as Company's system voltage. Suitable circuit breakers or similar equipment, as specified by Company, will be furnished by Seller at a location designated by Company to enable the separation or disconnection of the two electrical systems. Except in emergencies, the circuit breakers, or similar equipment, will be operated only by, or at the express direction of, Company personnel and will be accessible to Company at all times. In addition, a circuit breaker or similar equipment shall be furnished and installed by Seller to separate or disconnect Seller's generator.

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Louisville Gas and Electric Company

Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

PARALLEL OPERATION (Continued) ~~T~~

3. Seller will be responsible for operating the generator and all facilities owned by Seller, except as hereafter specified. Seller will maintain its system in synchronization with Company's system. ~~T~~ ~~T~~ ~~T~~ ~~T~~

4. Seller will (a) pay Company for all damage to Company's equipment, facilities or system, and (b) save and hold Company harmless from all claims, demands and liabilities of every kind and nature for injury or damage to, or death of, persons and/or property of others, including costs and expenses of defending against the same, arising in any manner in connection with Seller's generator, equipment, facilities or system or the operation thereof. ~~T~~ ~~D/N~~ ~~D/N~~ ~~D/N~~ ~~N~~

5. Seller will construct any additional facilities, in addition to generating and associated (interface) facilities, required for interconnection unless Company and Seller agree to Company's constructing such facilities, at Seller's expense, where Seller is not a Customer of Company. When Seller is a Customer of Company and Company is required to construct facilities different than otherwise required to permit interconnection, Seller shall pay such additional cost of facilities. Seller agrees to reimburse Company, at the time of installation, or, if agreed to by both parties, over a period of up to three (3) years, for any facilities including any hereafter required (but exclusive of metering equipment, elsewhere herein provided for) constructed by Company to permit Seller to operate interconnected with Company's system. When interconnection costs are repaid over a period of time, such payments will be made monthly and include interest on the unpaid balance at the percentage rate equal to the capital costs that Company would experience at such time by new financing, based on Company's then existing capital structure, with return on equity to be at the rate allowed in Company's immediately preceding rate case. ~~N~~ ~~D/N~~

6. Company will have the continuing right to inspect and approve Seller's facilities, described herein, and to request and witness any tests necessary to determine that such facilities are installed and operating properly; but Company will have no obligation to inspect or approve facilities, or to request or witness tests; and Company will not in any manner be responsible for Seller's facilities or any operation thereof. ~~N~~

7. Seller assumes all responsibility for the electric service upon Seller's premises at and from the point of any delivery or flow of electricity from Company, and for the wires and equipment used in connection therewith; and Seller will protect and save Company harmless from all claims for injury or damage to persons or property, including but not limited to property of Seller, occurring on or about Seller's premises or at and from the point of delivery or flow of electricity from Company, occasioned by such electricity or said wires and equipment, except where said injury or damage is proved to have been caused solely by the negligence of Company.

8. Each, Seller and Company, will designate one or more Operating Representatives for the purpose of contacts and communications between the parties concerning operations of the two systems.

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Standard Rate Rider LQF

Large Capacity Cogeneration and Small Power Production Qualifying Facilities

N

PARALLEL OPERATION (Continued)

9. Seller will notify Company's Energy Control Center prior to each occasion of Seller's generator being brought into or (except in cases of emergencies) taken out of operation.

10. Company reserves the right to curtail a purchase from Seller when:
    (a) the purchase will result in costs to Company greater than would occur if the purchase were not made but instead Company, itself, generated an equivalent amount of energy; or
    (b) Company has a system emergency and purchases would (or could) contribute to such emergency.

    Seller will be notified of each curtailment.

TERMS AND CONDITIONS

Except as provided herein, conditions or operations will be as provided in Company's Terms and Conditions.

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 6

Responding Witness: William Steven Seelye

Q-6. Refer to the Supplemental Testimony of William Steven Seelye (Supplemental Seelye Testimony), page 9.

a. Explain why LG&E is not offering NMS-2 customers the option to enter into the 20-year SQF PPA price.

b. Provide empirical data that supports customers within LG&E's territory not providing generation for a 20-year period.

A-6. a. Mr. Seelye disagrees with the premise of the question. Any NMS-2 customer who desires to be compensated at 20-year SQF PPA rates may enter into a 20-year contract with KU under Rider SQF to sell *all* of the output of the customer's facility to KU. But it is difficult to comprehend why any NMS-2 customer would choose to do so; any energy an NMS-2 customer generates and consumes is effectively compensated at the full retail rate, including all rider mechanisms.

b. The Companies' net metering tariffs have not been in place for 20 years. The Companies have served relatively few net metering customers until the last five years, with the most rapid increase occurring during the last three years. The Companies therefore do not have sufficient longitudinal data to estimate the length of time that a net metering customer would likely keep their facilities in place. See the response to Joint Intervenors 2-8.

Mr. Seelye would note that the underlying premise of this request seems to be that contracts do not matter; if it would appear to be in a party's interest to do something over a certain period, why bother entering into a contract to ensure the party would continue do what seems to be in the party's interest? The answer is that what might seem to be in a party's interest at one point in time might not be later on *unless* there is a contract in place that clearly states the terms of an agreement, *including consequences for noncompliance*. That is precisely why QFs that do not enter into legally enforceable obligations cannot receive capacity payments: without an enforceable obligation, a utility has no reasonable basis to assume a QF's capacity will continue to be available to help serve the utility's customers.

With regard to NMS-2 customers, the same is true. Though it might seem to be in an NMS-2 customer's interest to keep the an eligible electric generating facility in place and functioning for 20 years, the customer's interest might change if the facility was damaged and the customer lacked the resources to repair it. Also, if an NMS-2 customer sells her residence and the new owner finds the facility unappealing and removes it, there is nothing to prevent such removal. Therefore, without having a long-term legally enforceable obligation in place with an NMS-2 customer, it would be unreasonable to provide the customer any capacity credit.

Mr. Seelye would note that this position is entirely consistent with the Commission's statement in Case No. 2020-0016 that a 20-year level-price power purchase agreement for the entire output of a 100 MW solar facility—with liquidated damages if the facility fails to meet availability requirements—did *not* provide any capacity: "[T]he instant PPA is for nonfirm energy only, and includes no capacity."[3] If a 20-year contract with a credit-worthy entity supporting liquidated damages for non-availability does not provide any capacity, it must be the case that an NMS-2 customer's generating facility that is not backed by a contract or liquidated damages of any kind does not provide compensable capacity.

---

[3] *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source under Green Tariff Option #3,* Case No. 2020-00016, Order at 12 (PSC Ky. May 8, 2020).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 7

Responding Witness: David S. Sinclair

Q-7. Refer to the Supplemental Seelye Testimony, page 9, lines 11–12. Provide all studies and workpapers that substantiate the claim that "nearly all customer-generators taking service under NMS-2 will most likely have Fixed-Tilt Solar installations."

A-7. Based on the Companies' records, as of November 30, 2020, KU serves 3 distributed generation customers with combination wind/solar facilities, 1 hydroelectric facility, and 586 solar facilities; and LG&E serves 3 distributed generation customers with combination wind/solar facilities and 681 solar facilities. To the best of the Companies' knowledge and belief, all solar facilities are fixed-tilt systems, with the vast majority being fixed-tilt roof-top solar installations. The Companies are aware of only a few fixed-tilt ground-mounted behind-the-meter solar installations.

Additionally, according to Berkley Lab's *Tracking the Sun* report, only a very small percentage of residential and small non-residential (<=100 kW DC) arrays nationwide are mounted with tracking technology (see slide 13 in the attached document). There is no reason to expect this trend to change.

Distributed Solar 2020 Data Update*

*Based on data otherwise published within Berkeley Lab's *Tracking the Sun* report. Updated data files and data visualizations are available at: trackingthesun.lbl.gov

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Lawrence Berkeley National Laboratory
[1]Corresponding authors

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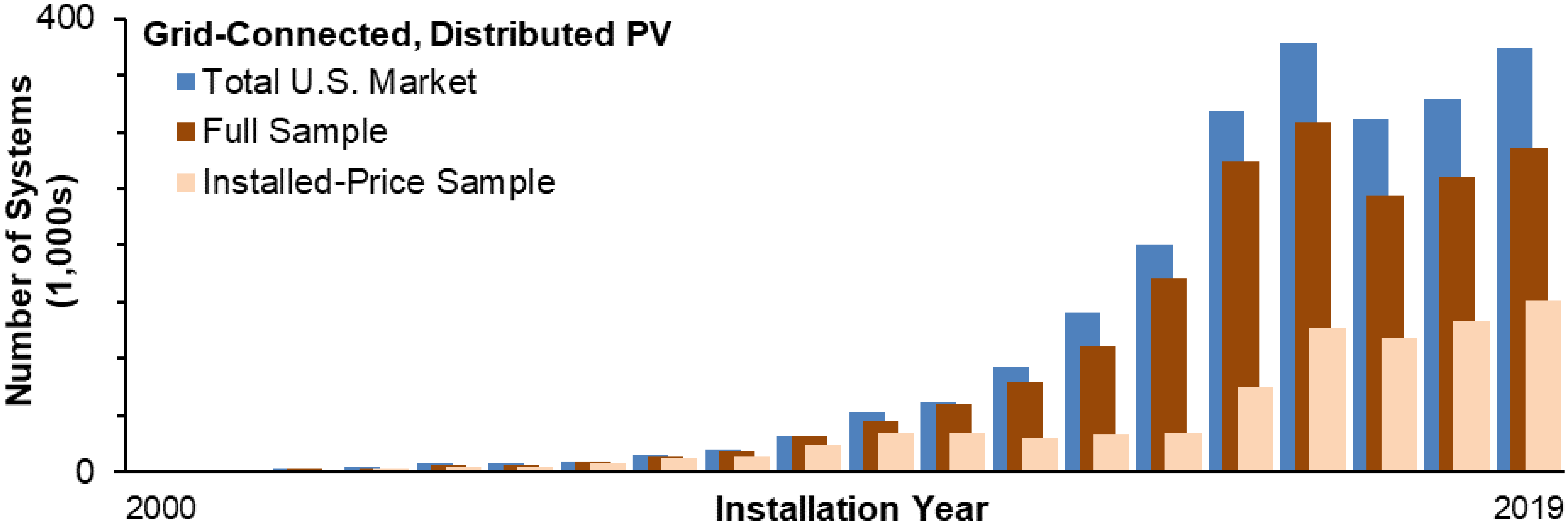
Overview

- **Covers grid-connected, distributed photovoltaic (PV) systems installed through 2019**
  - "Distributed" PV consists of residential and non-residential systems that are roof-mounted (of any size) or are ground-mounted up to 5 MW_{AC}
  - Ground-mounted projects >5 MW_{AC} are covered in Berkeley Lab's "Utility-Scale Solar Data Update: 2020 Edition"
- **Includes data on** installed system prices and other project characteristics, including: system sizing, module efficiency, module-level power electronics, inverter-loading ratios, solar+storage installations, mounting configuration, panel orientation, third-party ownership, and customer segmentation
- **Published in conjunction with this slide deck** (at trackingthesun.lbl.gov) **are:**
  - An Excel file containing summary data tables corresponding to each of the figures presented in this slide deck
  - A public data file with all non-confidential project-level data
  - Interactive data visualizations that allow further exploration of the data

Sample Size Relative to Total U.S. Market



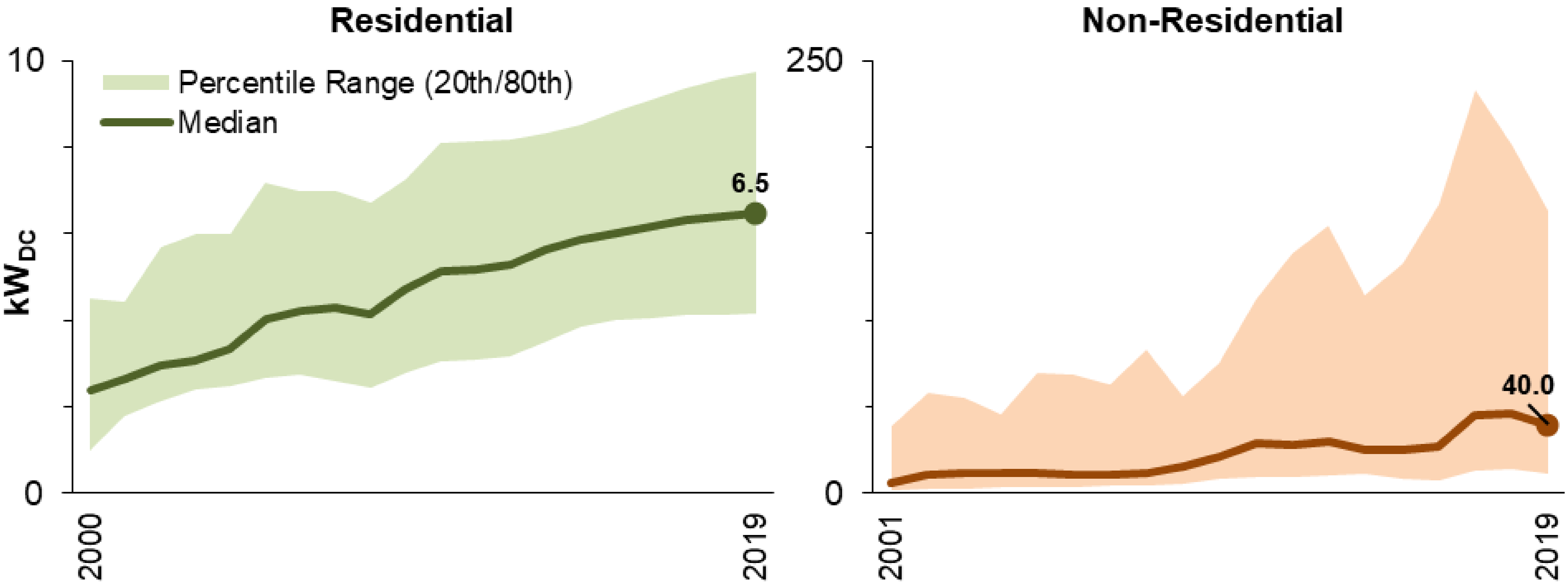
Notes: Total U.S. distributed PV installations are based on data from Interstate Renewable Energy Council (IREC) for all years through 2010 and from Wood Mackenzie and SEIA's annual year-in-review Solar Market Insight report for each year thereafter.

See Appendix for details on data sources, definitions, and data cleaning methods

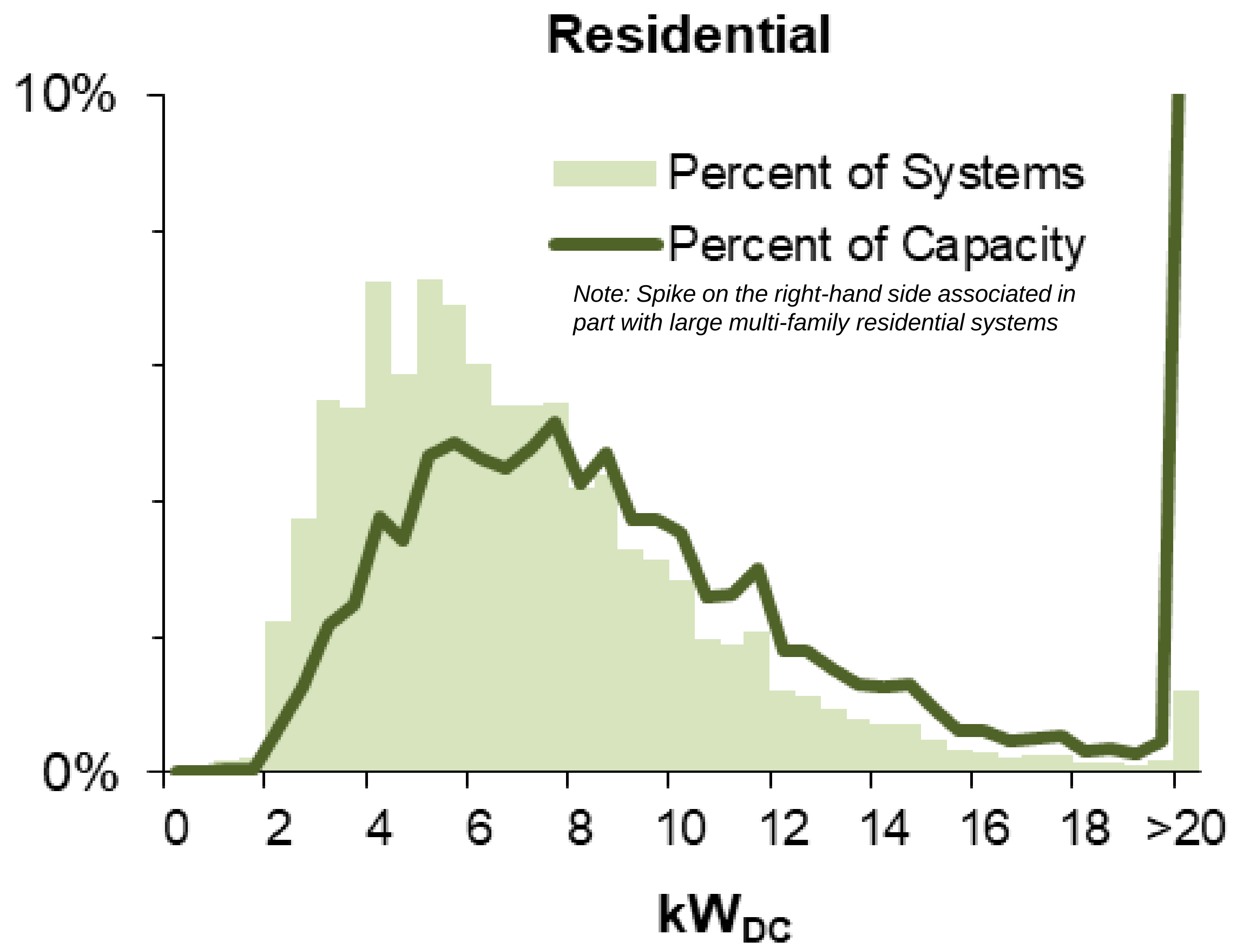
Distributed PV System Characteristics

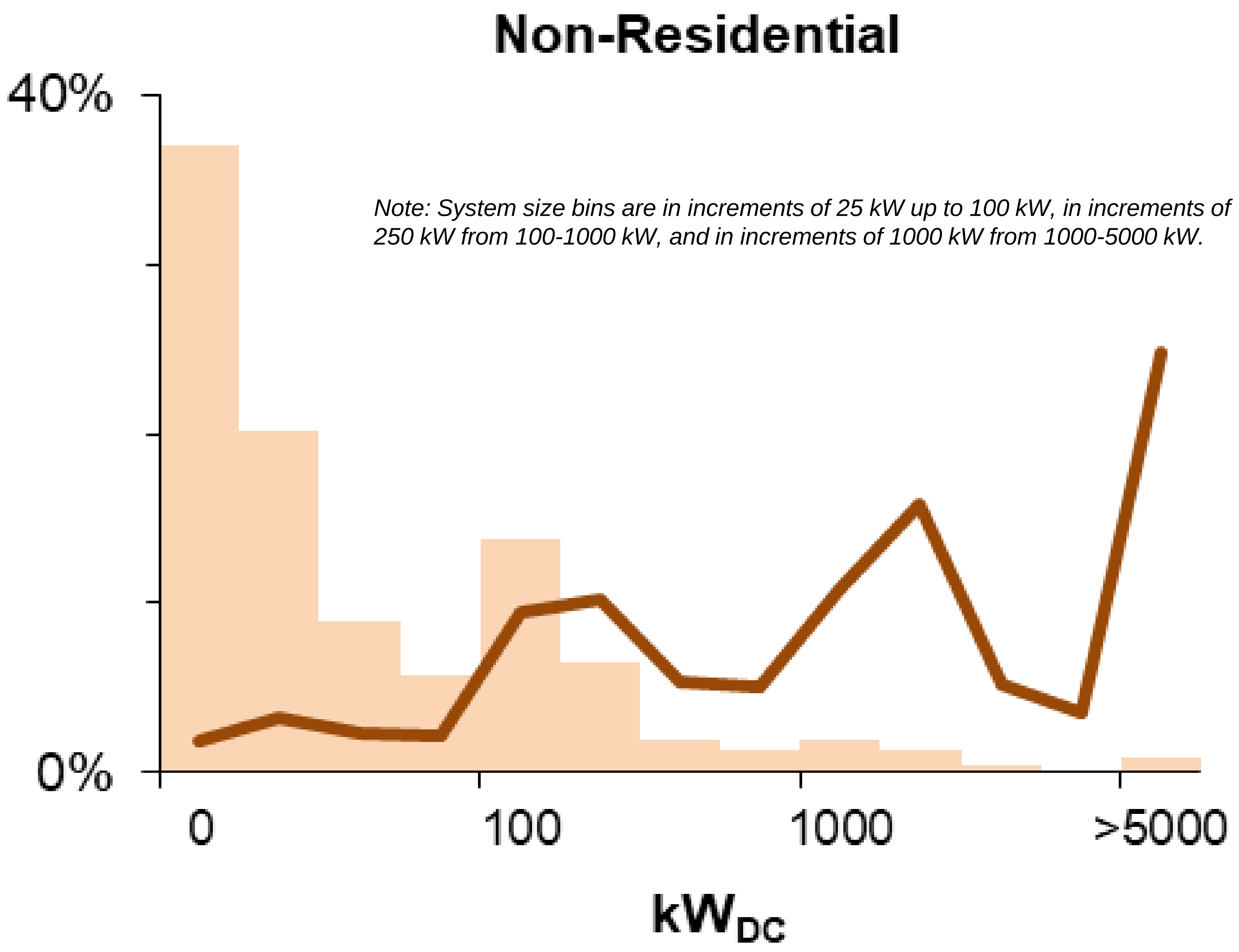
Based on Full Sample

System Size Trends

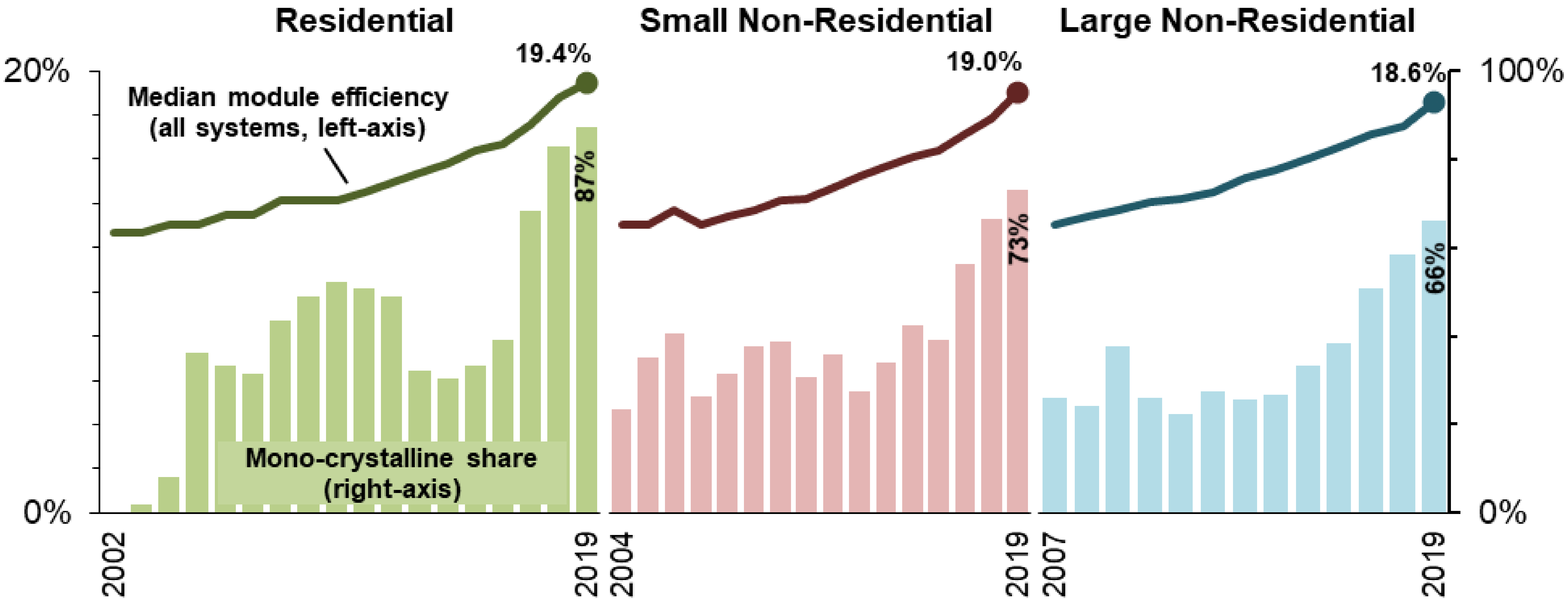


System Size Distribution for 2019 Systems



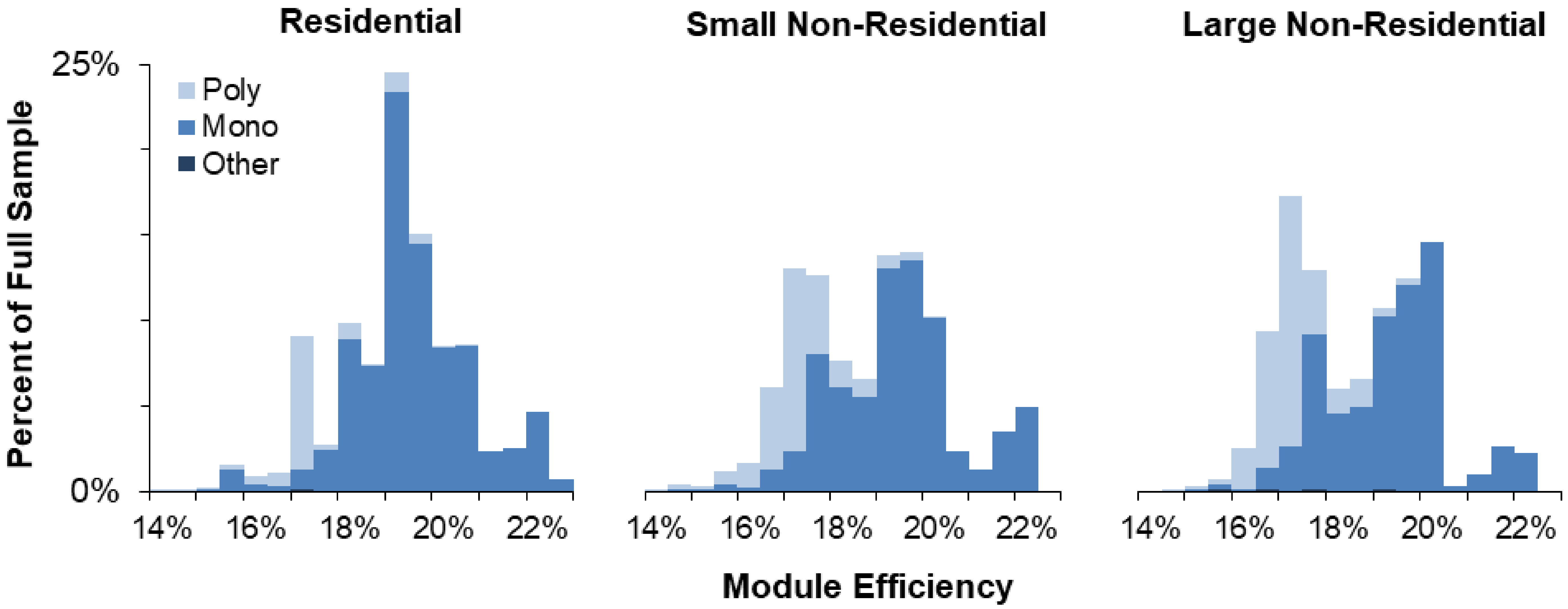


Median Module Efficiency and Mono-Crystalline Share

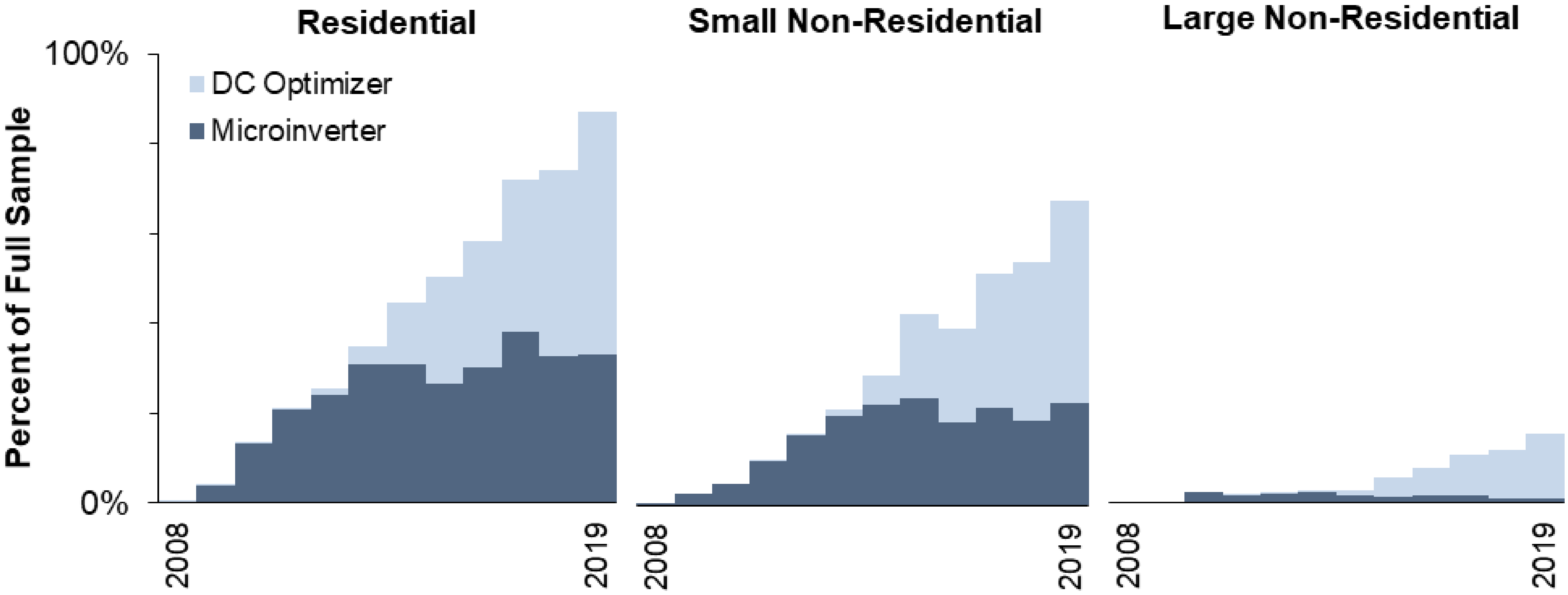


Notes: The range of years shown varies across customer segments depending on the data availability and sample size. In these charts and elsewhere, "small" vs. "large" non-residential are based on a 100 kW size threshold.

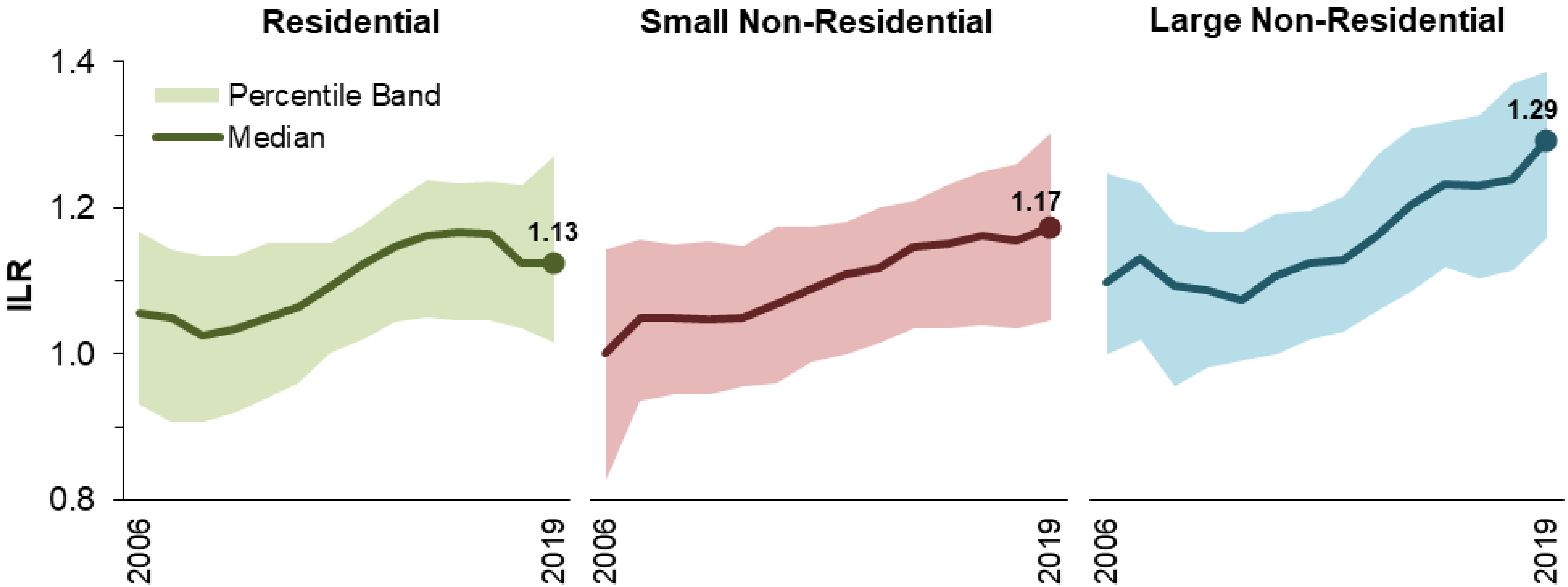
Module Efficiency Distribution for 2019 Systems



Module-Level Power Electronics Adoption Trends



Inverter-Loading Ratio Trends



Notes: The Percentile Band refers to the range between the 20th and 80th percentiles.

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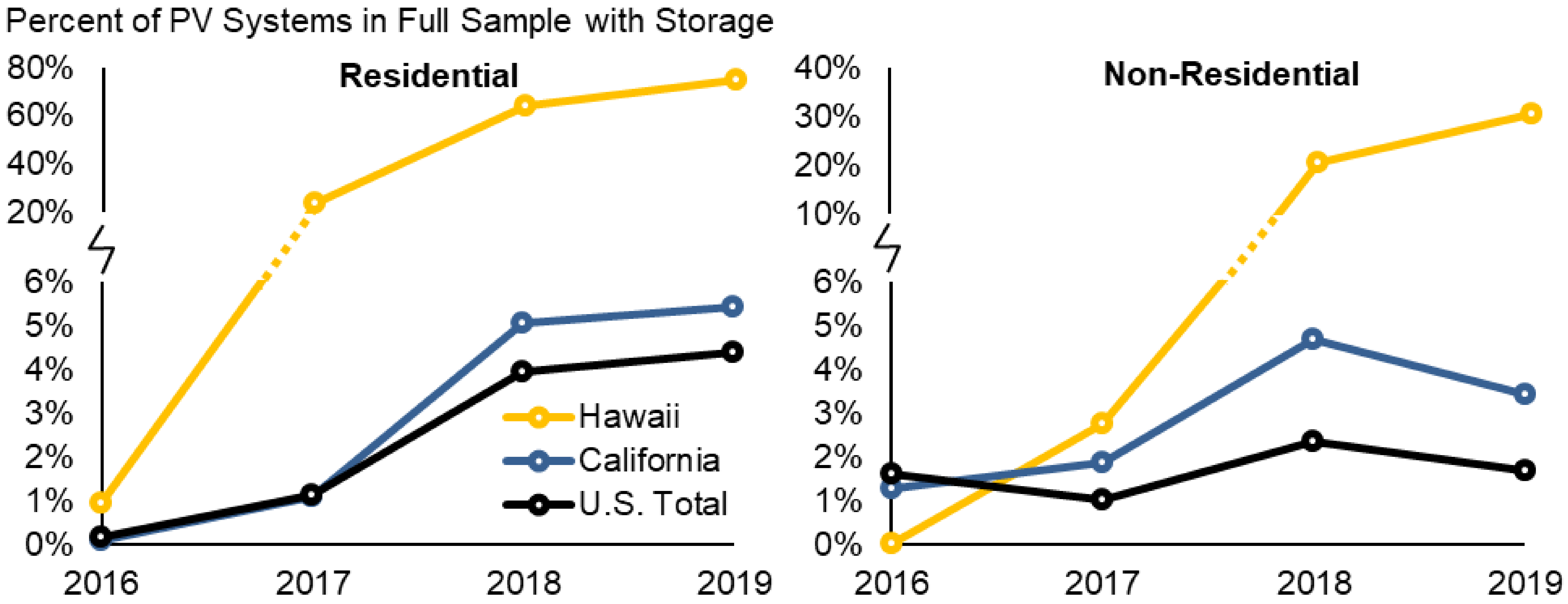
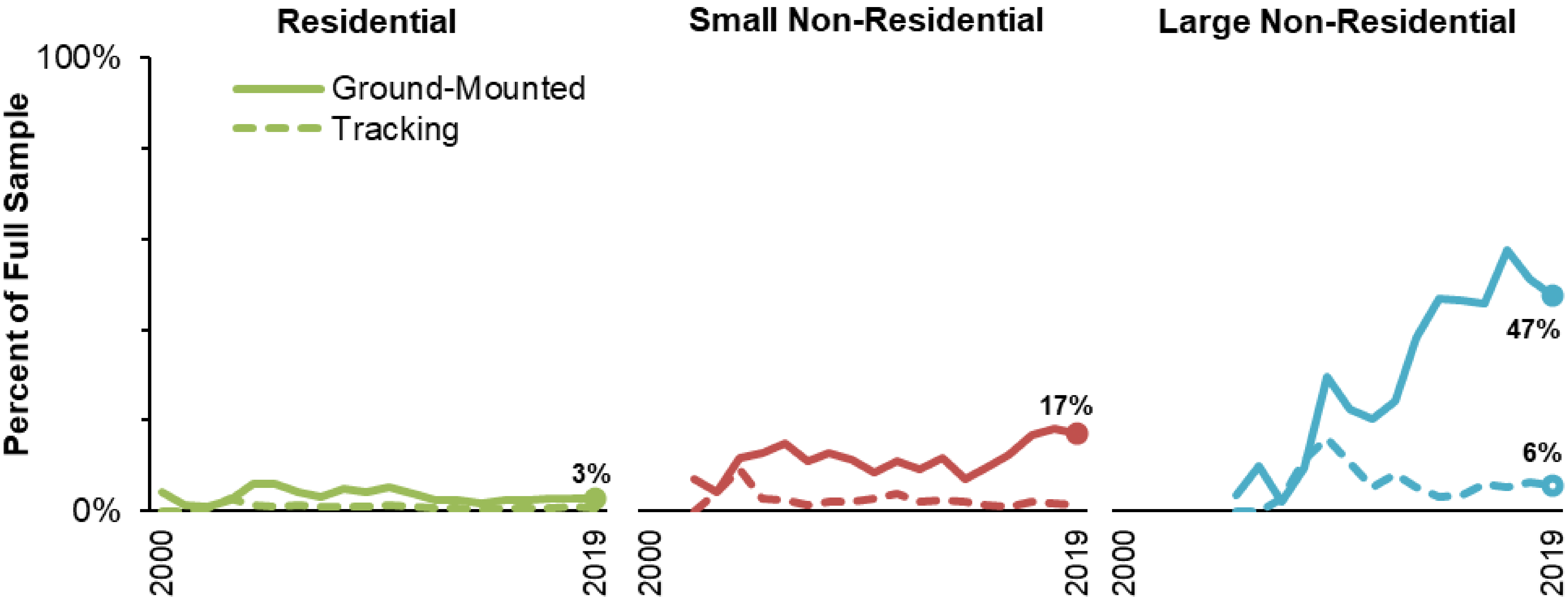
Paired Solar+Storage Trends

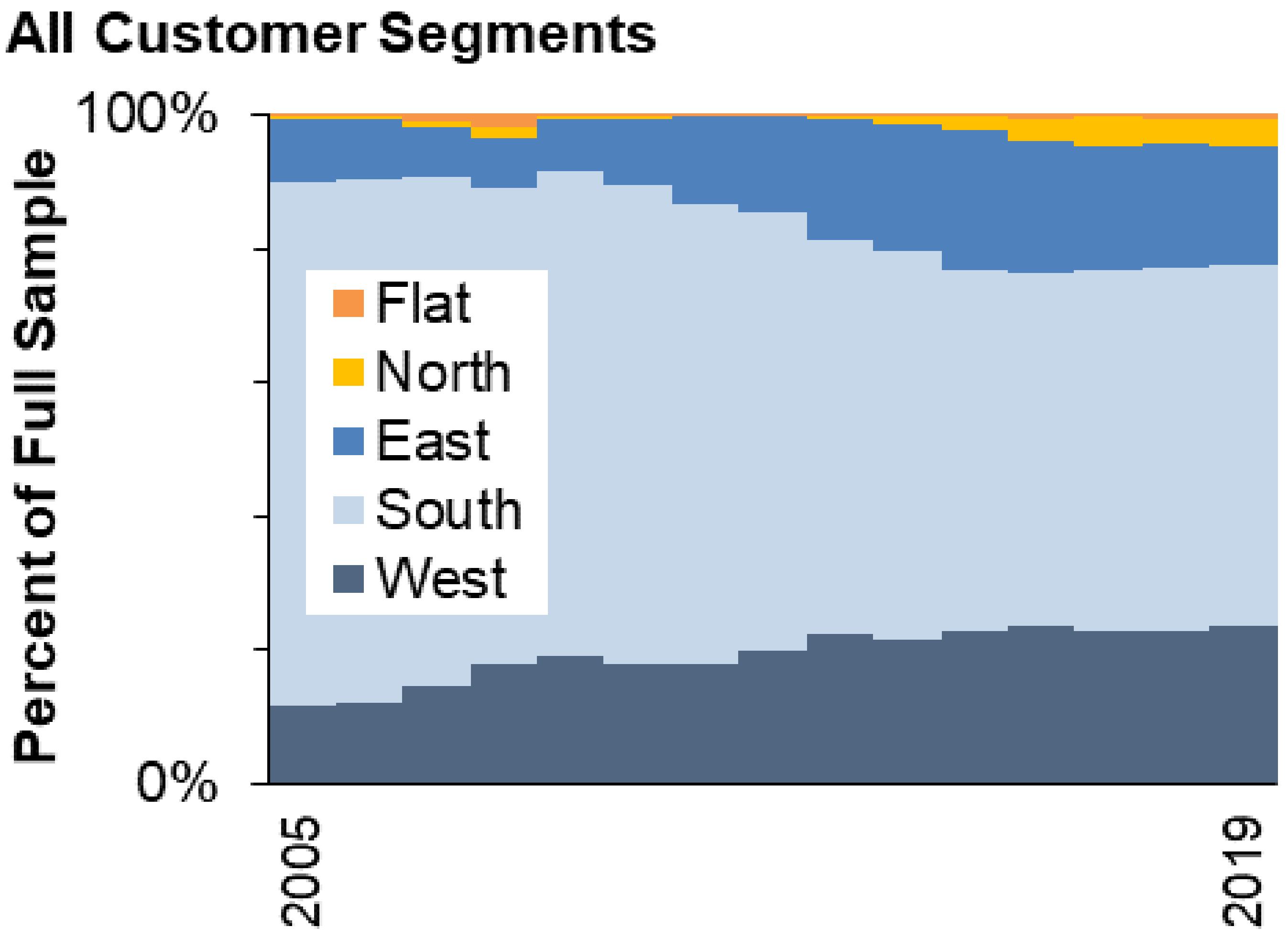


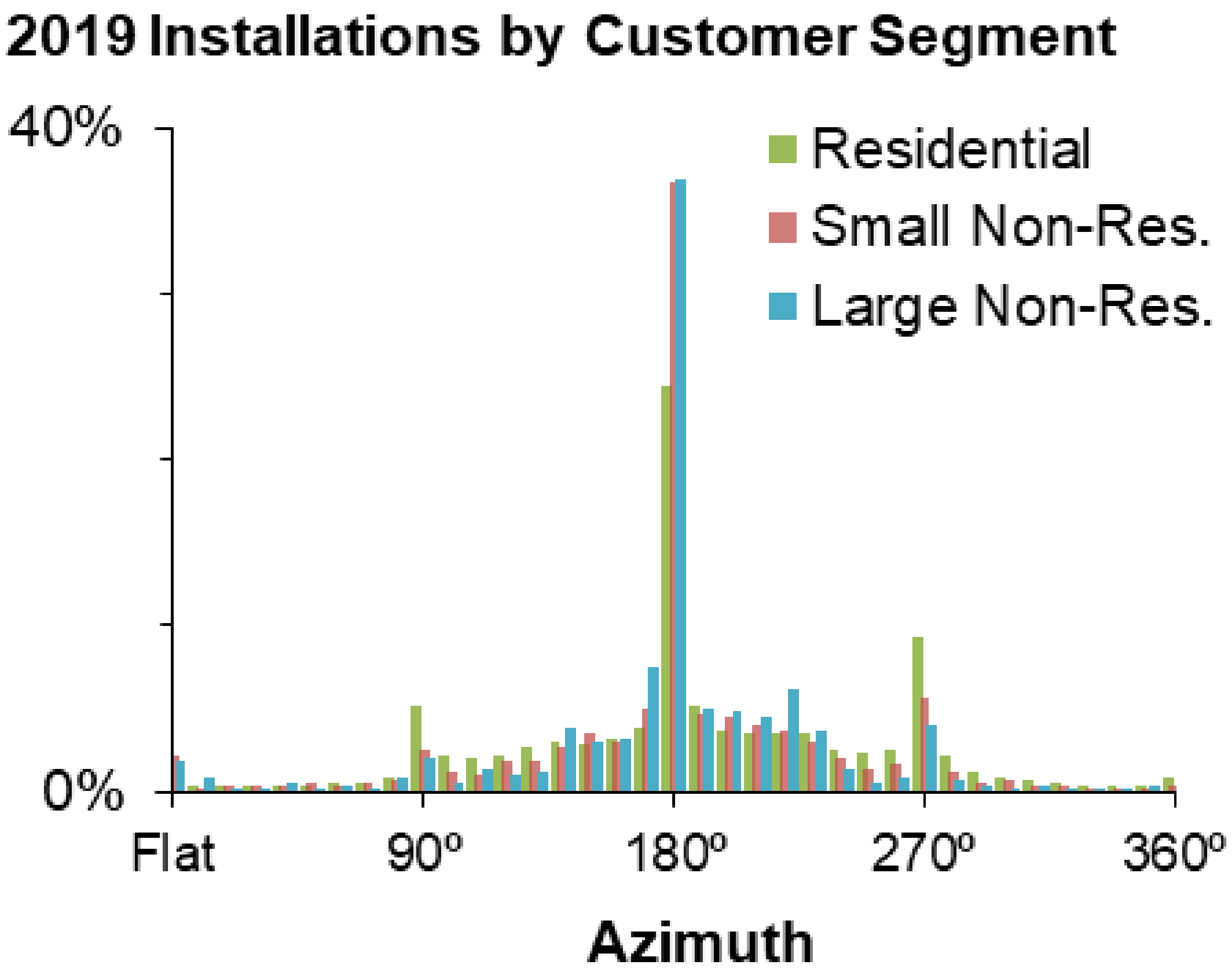
Panel Mounting Trends



Notes: Summary statistics for any given year are shown only if at least 20 observations are available.

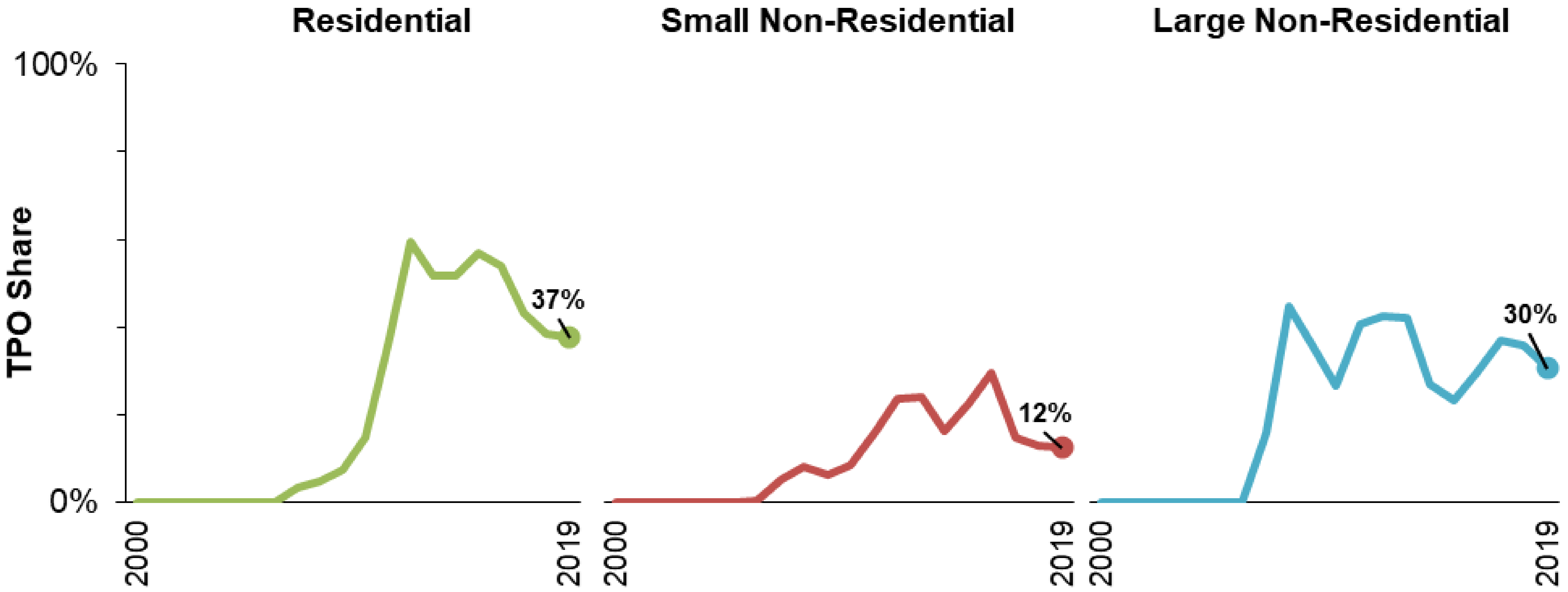
Panel Orientation Trends



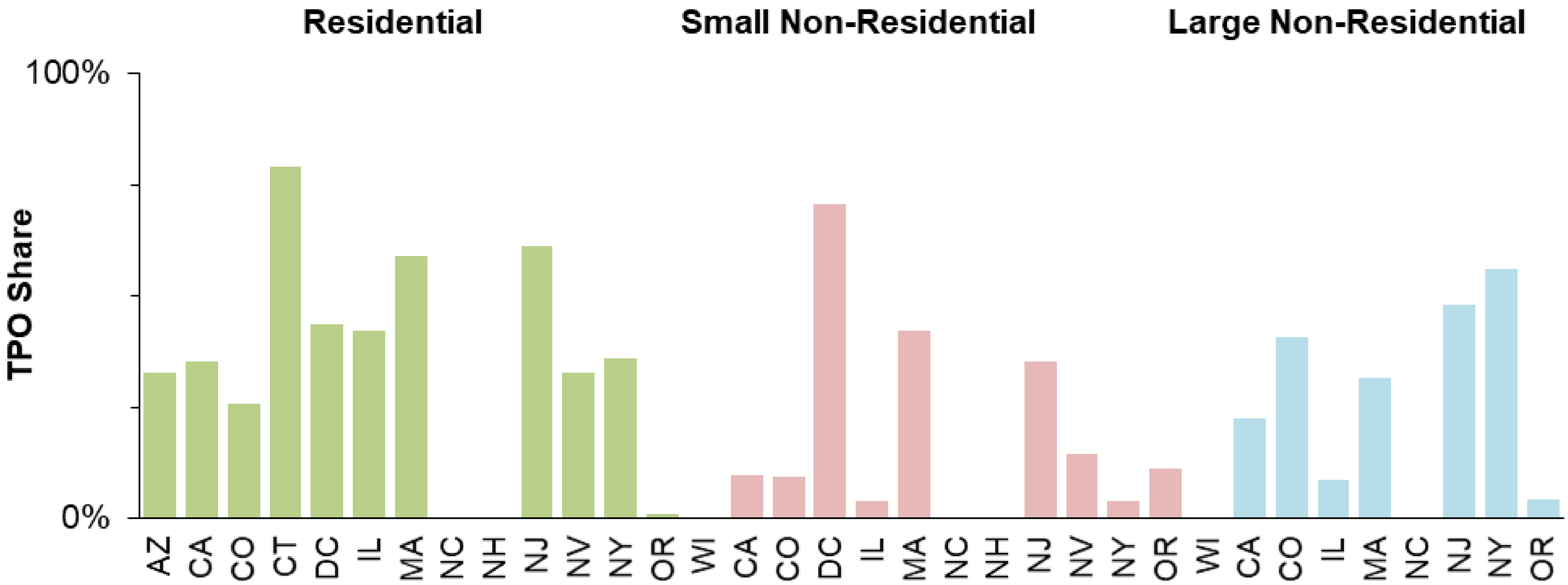


Notes: In the left-hand figure, azimuths are grouped according to cardinal compass directions ±45º (e.g., systems within ±45º of due-south are considered south-facing). Both figures exclude tracking systems.

Third-Party Ownership (TPO) Trends



TPO Shares by State in 2019



Notes: States included only if at least 20 observations available, if ownership is known for at least 50% of the observations, and only if the underlying data sources are deemed to be representative of the state as a whole.

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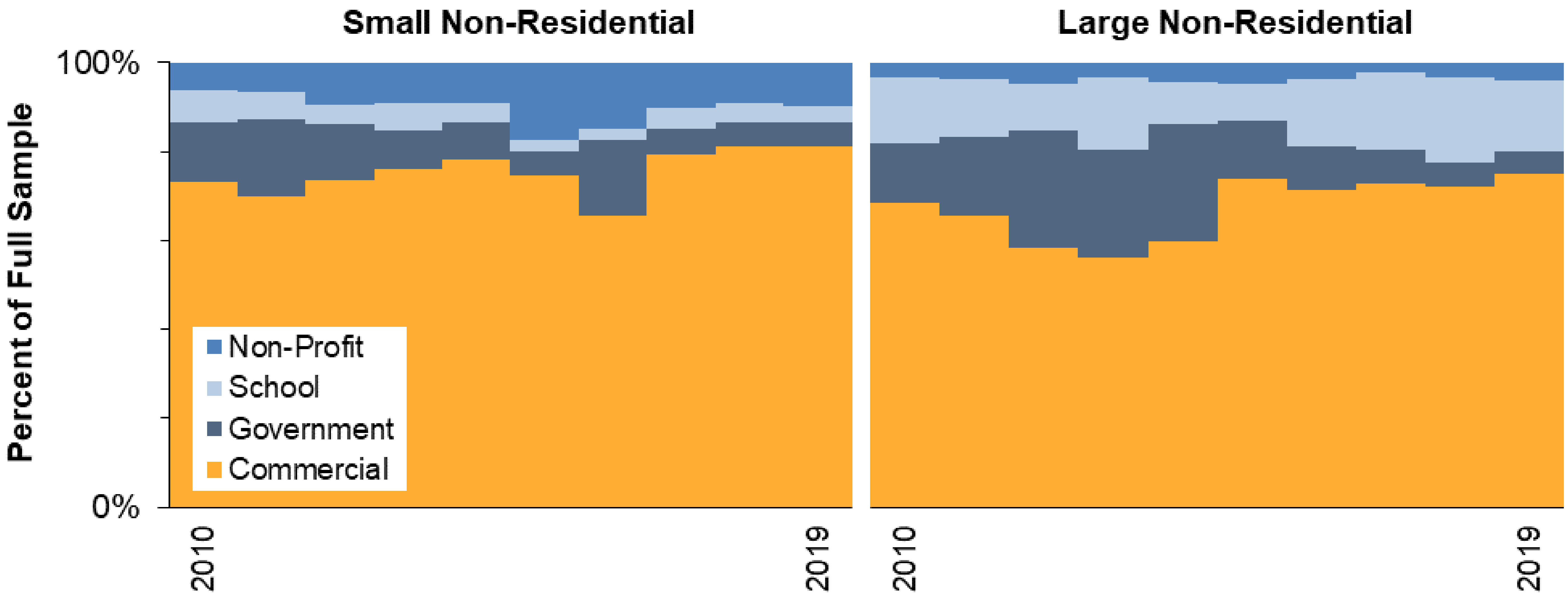
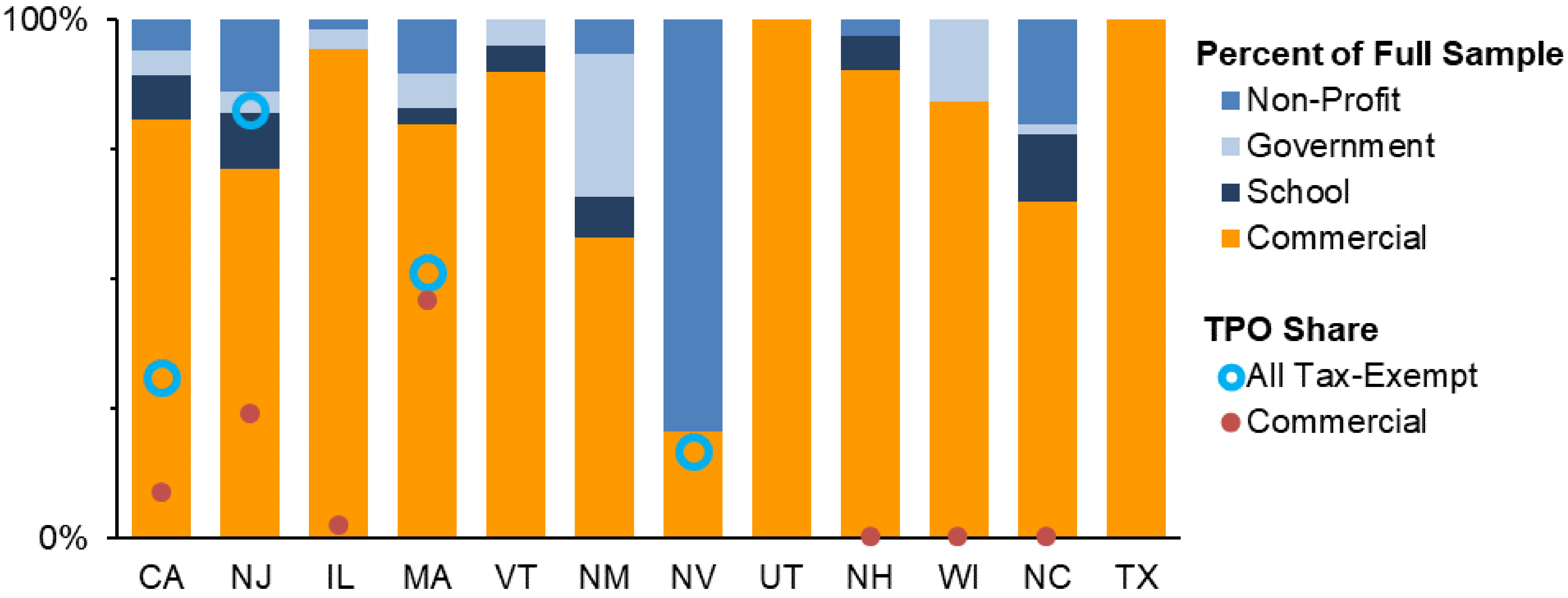
Non-Residential Customer Segmentation over Time



Non-Residential Customer Segmentation by State in 2019



Notes: Tax-exempt customers include non-profit, government, and schools. States included only if at least 20 observations available with known non-residential subsegment. TPO shares shown only if ownership status is known for at least 50% of the respective subsegment (commercial or tax-exempt).

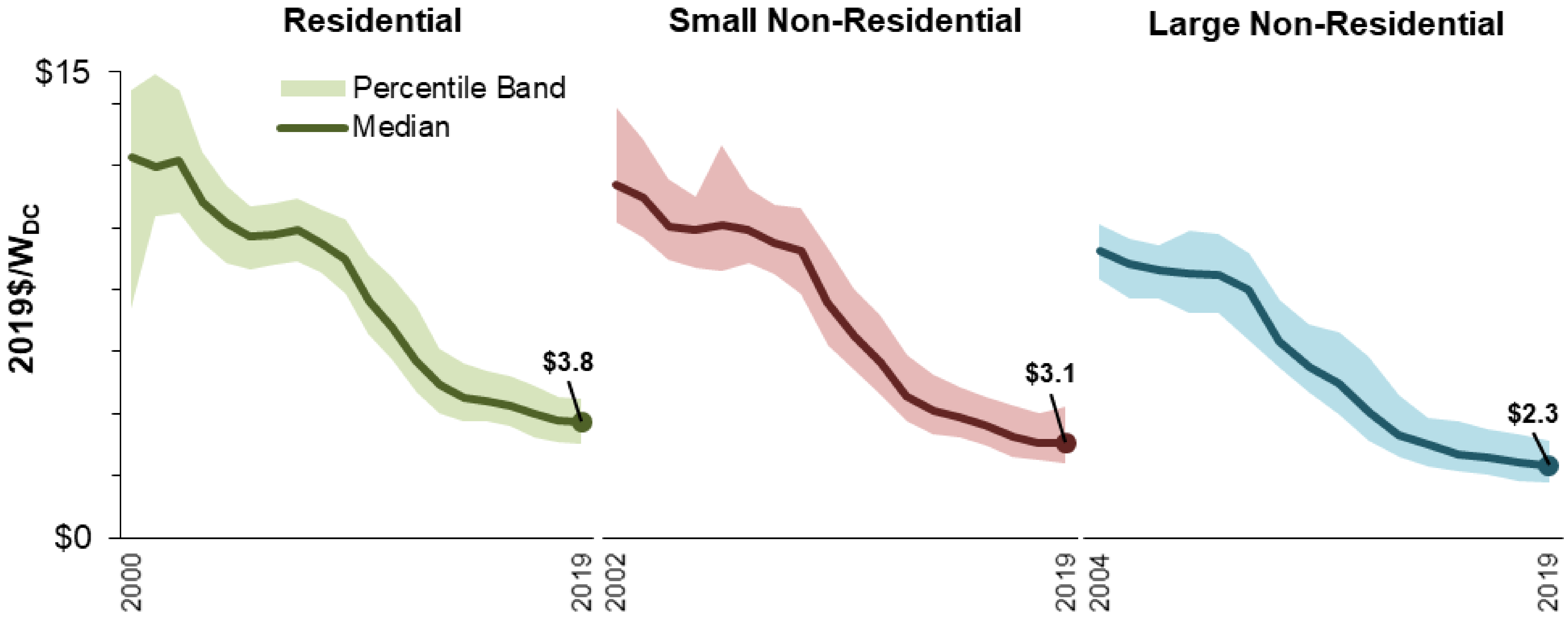
Temporal Trends in Installed Prices

Based on Installed-Price Sample

A Few Notes on Installed-Price Data

- Differs from the underlying cost borne by the developer or installer (price ≠ cost)
- Unless otherwise noted, excludes TPO, battery storage, and self-installed systems
- Historical (i.e., systems installed through 2019) and therefore may not be representative of systems installed more recently or current quotes for prospective projects
- Self-reported by PV installers or customers; susceptible to inconsistent reporting practices

National Installed Price Trends



Notes: The range of years shown varies across customer segments depending on the data availability and sample size. The Percentile Band refers to the range between the 20th and 80th percentiles

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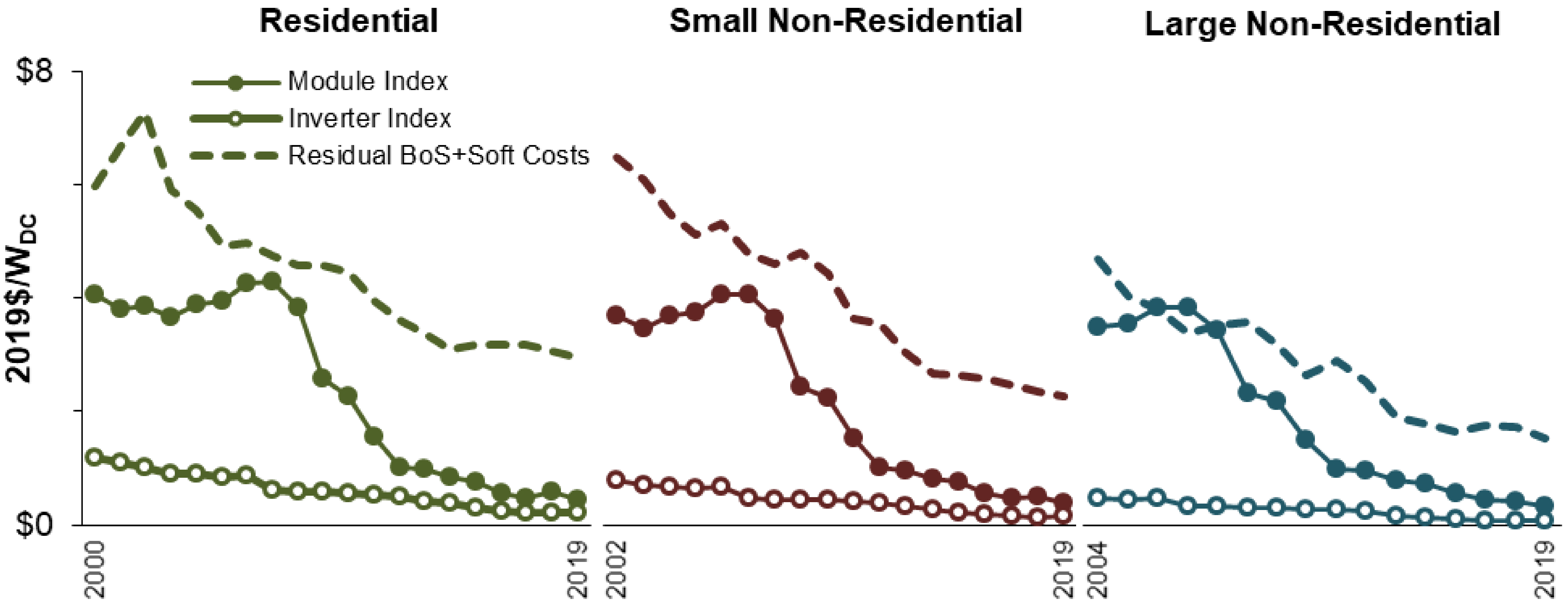
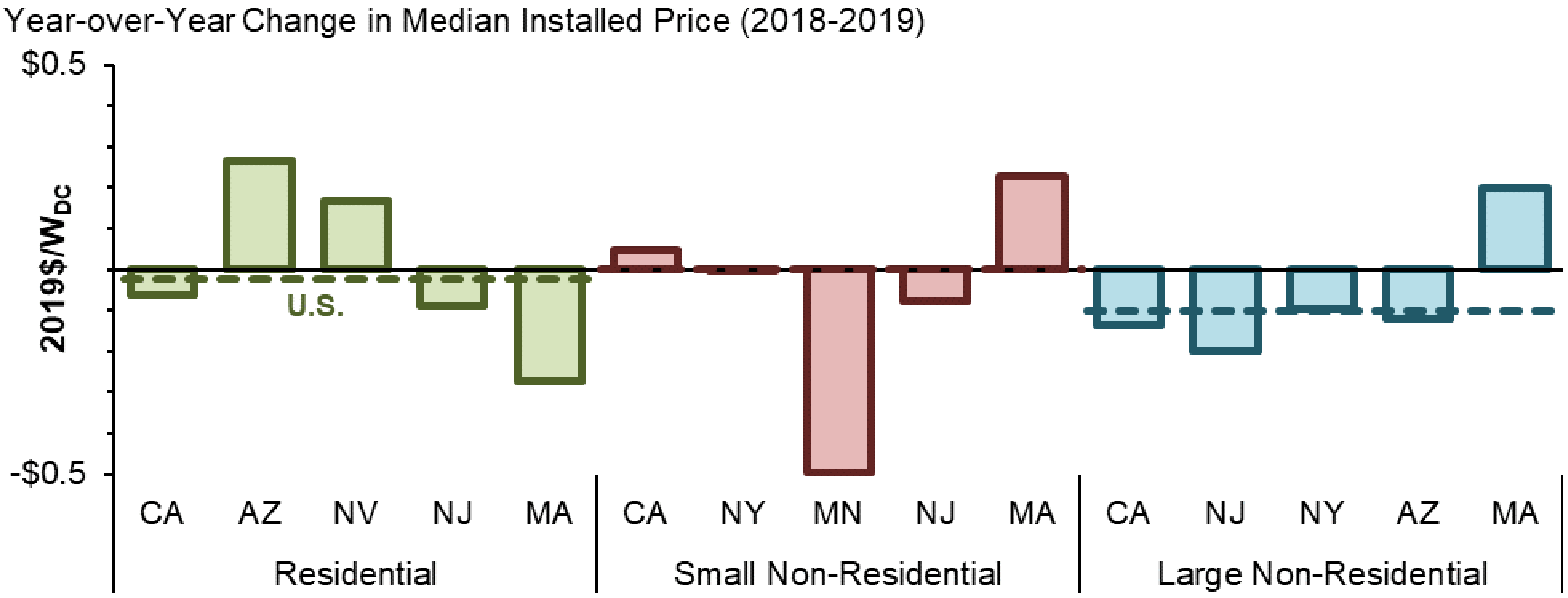
Underlying Trends in Component Costs



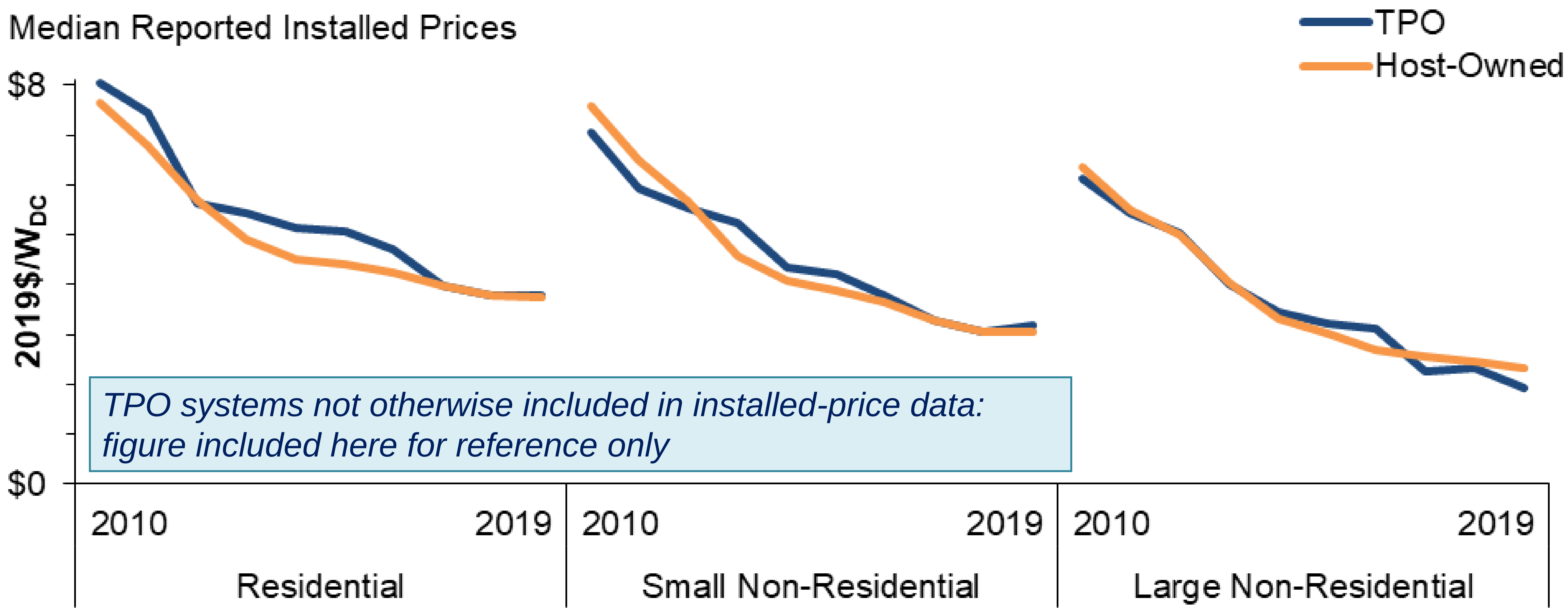
Notes: The Module and Inverter Price Indices are based on data from SPV Market Research and Wood Mackenzie, with adjustments by Berkeley Lab in order to extend those indices back in time and to differentiate among customer segments. The Residual term is calculated as the median installed price for each customer segment minus the corresponding Module and Inverter Price Indices with a one-year lag.

Year-over-Year Trends Nationally and for Select States



Notes: The five largest state markets in the full data sample (based on 2019 systems) are shown for each customer segment. Dashed lines show the year-over-year change in national median installed prices.

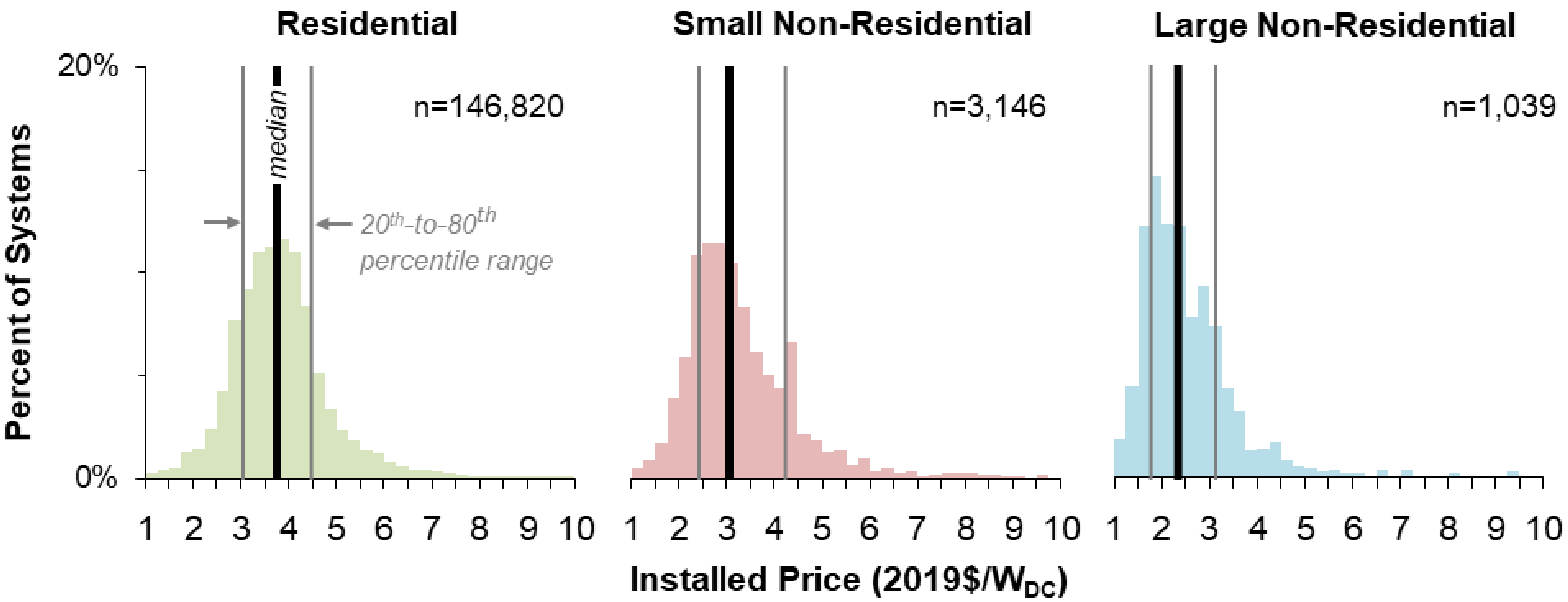
Installed Prices Reported for TPO vs. Host-Owned Systems



Variation in Installed Prices

Based on Installed-Price Sample

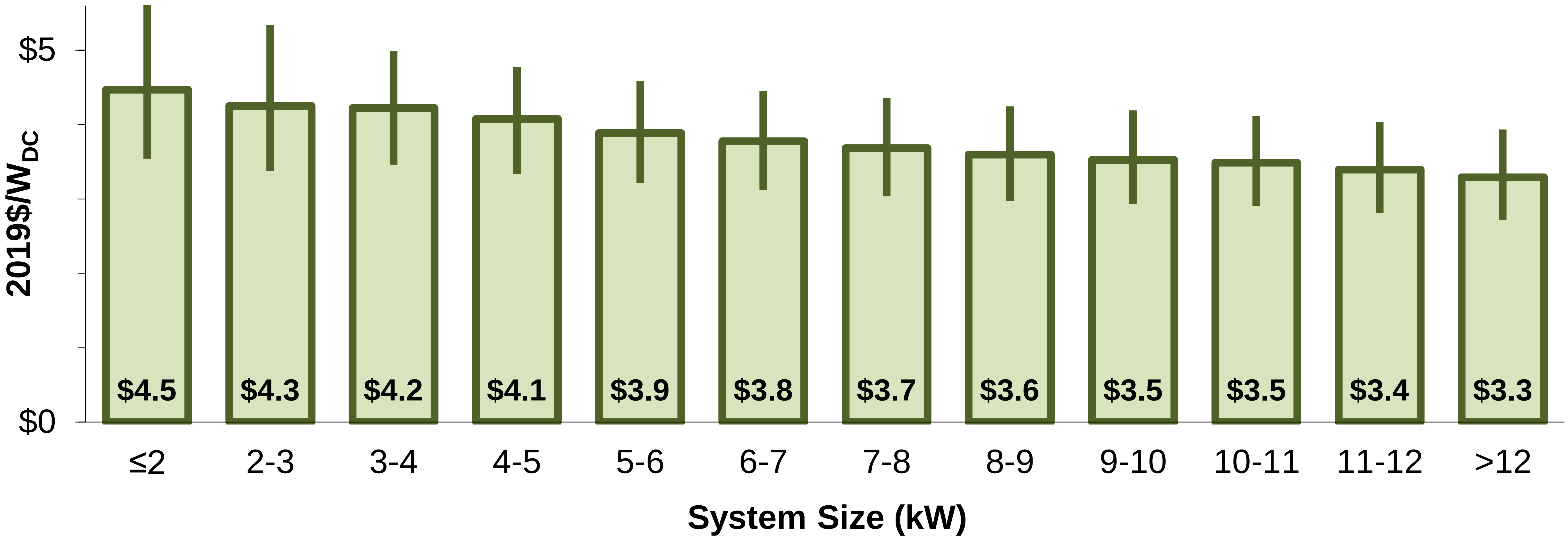
Installed Price Distributions for 2019 Systems



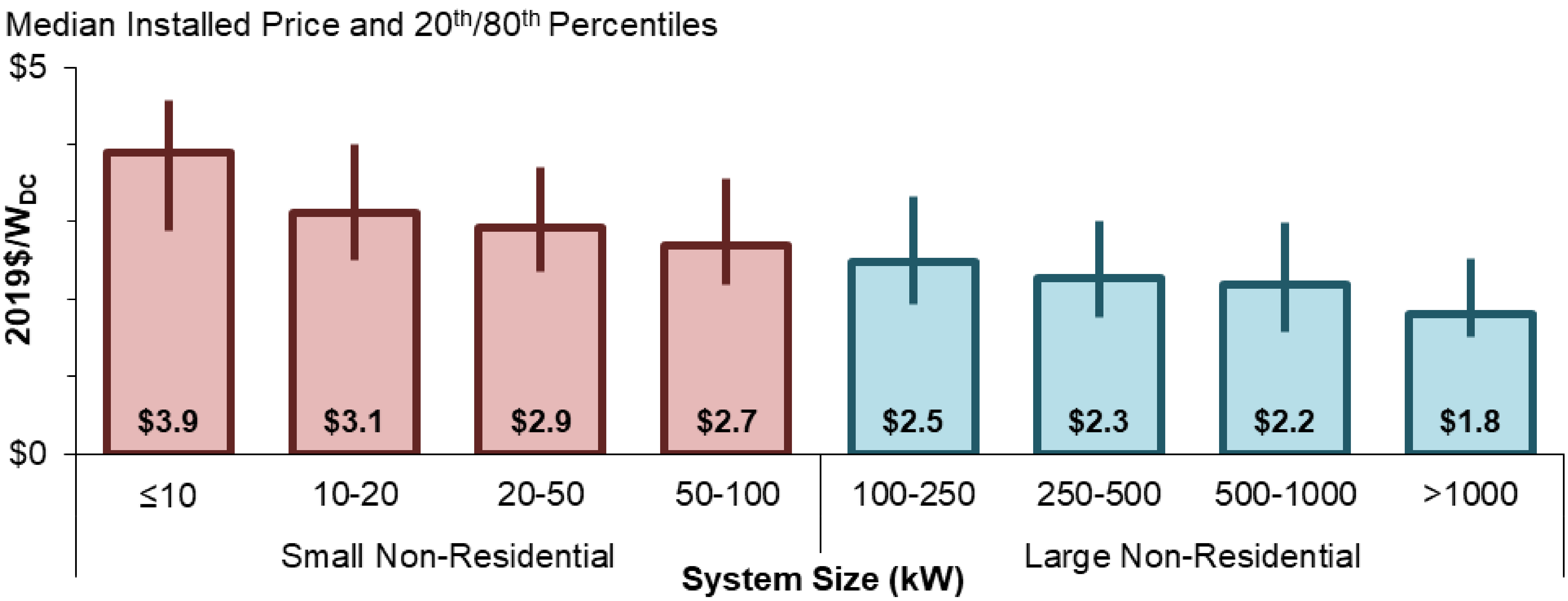
Installed Price Differences by System Size

2019 Residential Systems

Median Installed Price and 20th/80th Percentiles

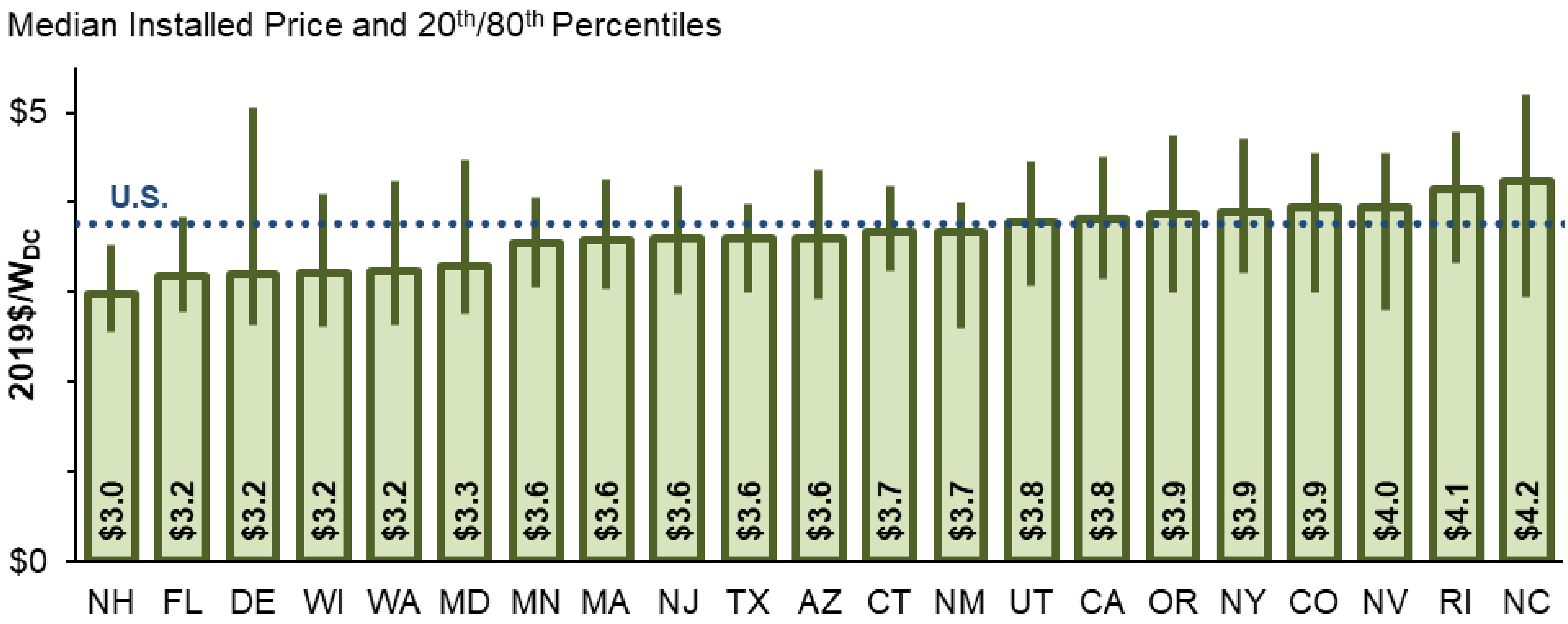


Installed Price Differences by System Size
2019 Non-Residential Systems



Installed Price Variation by State

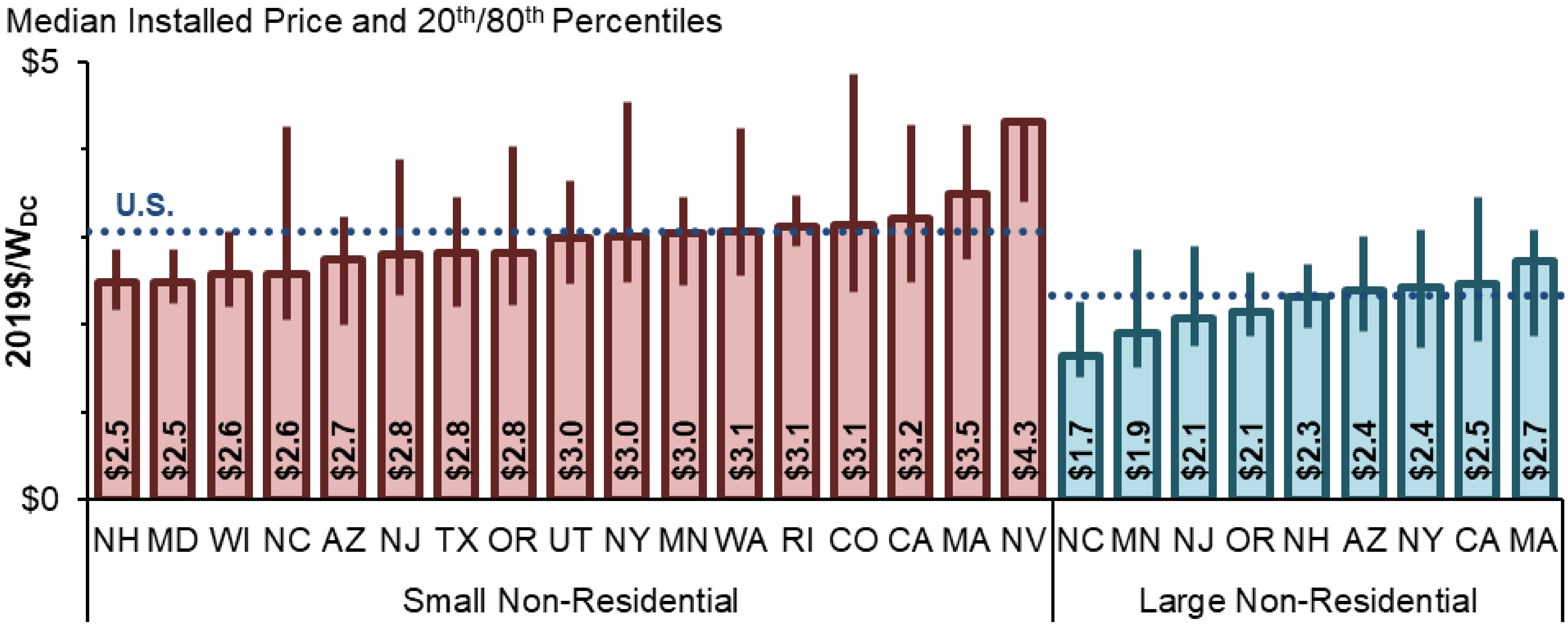
2019 Residential Systems



Notes: Data shown only if at least 20 observations are available for a given state.

Installed Price Variation by State

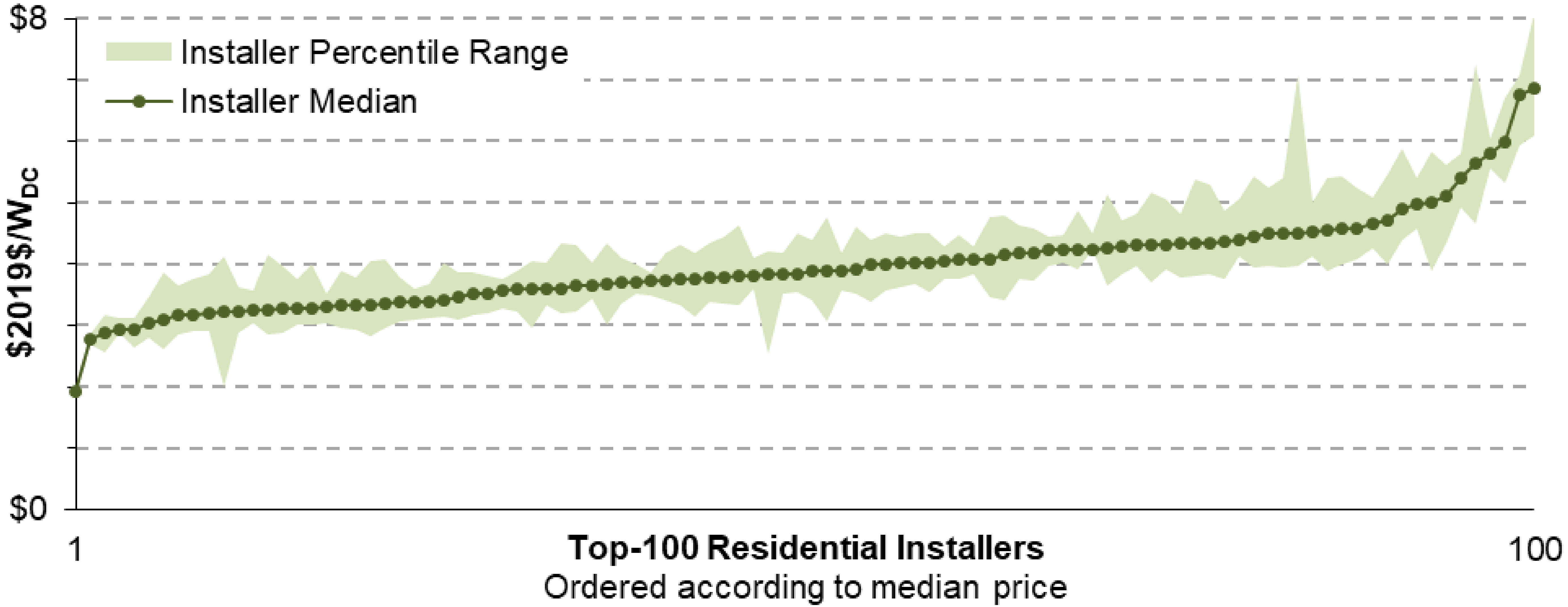
2019 Non-Residential Systems



Notes: Data shown only if at least 20 observations are available for a given state.

Installed Price Variation across the Top-100 Installers

2019 Residential Systems



Notes: Each dot represents the median installed price of an individual installer, ranked from lowest to highest, while the shaded band shows the 20th to 80th percentile range for that installer.

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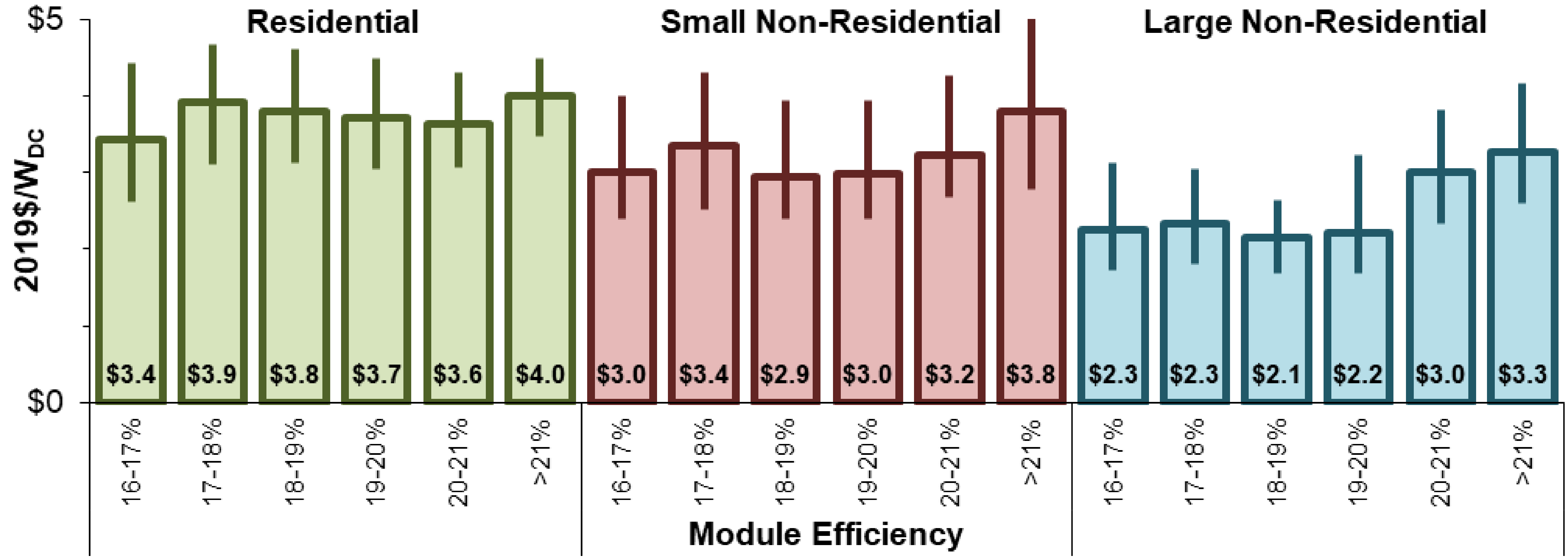
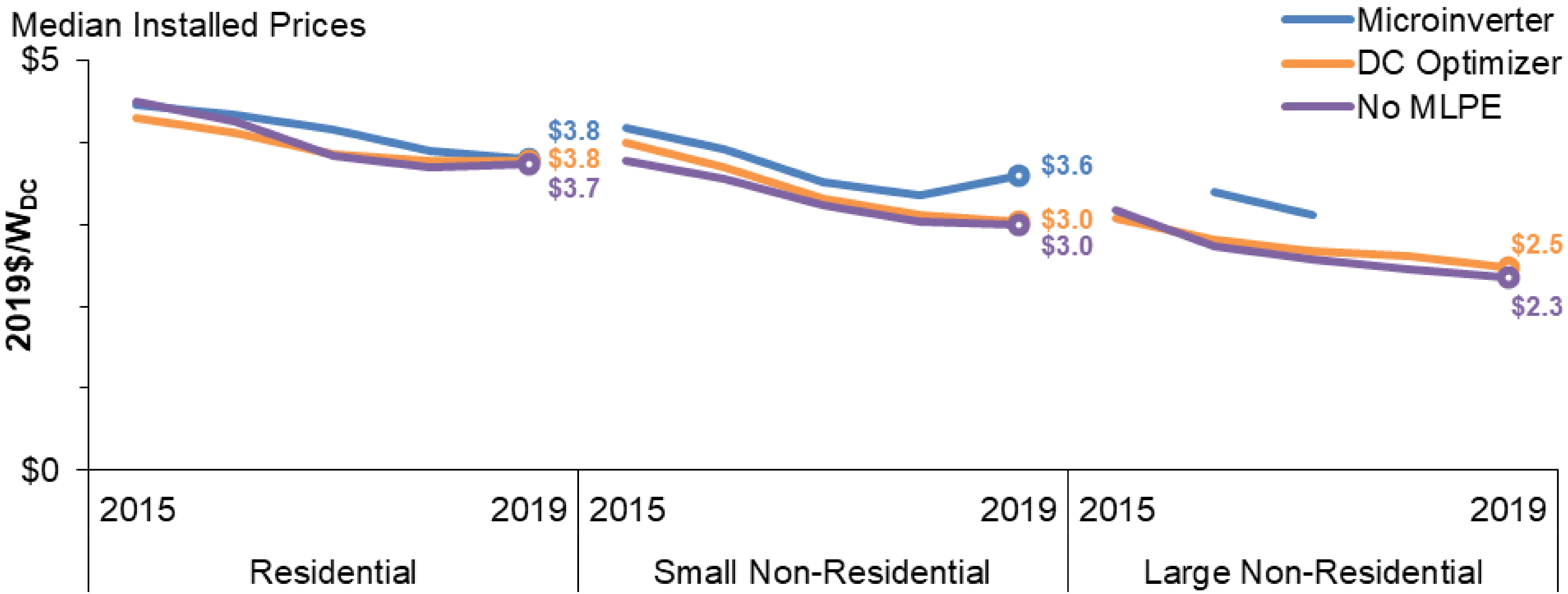
Installed Price Variation by Module Efficiency
2019 Systems

Median Installed Price and 20th/80th Percentiles

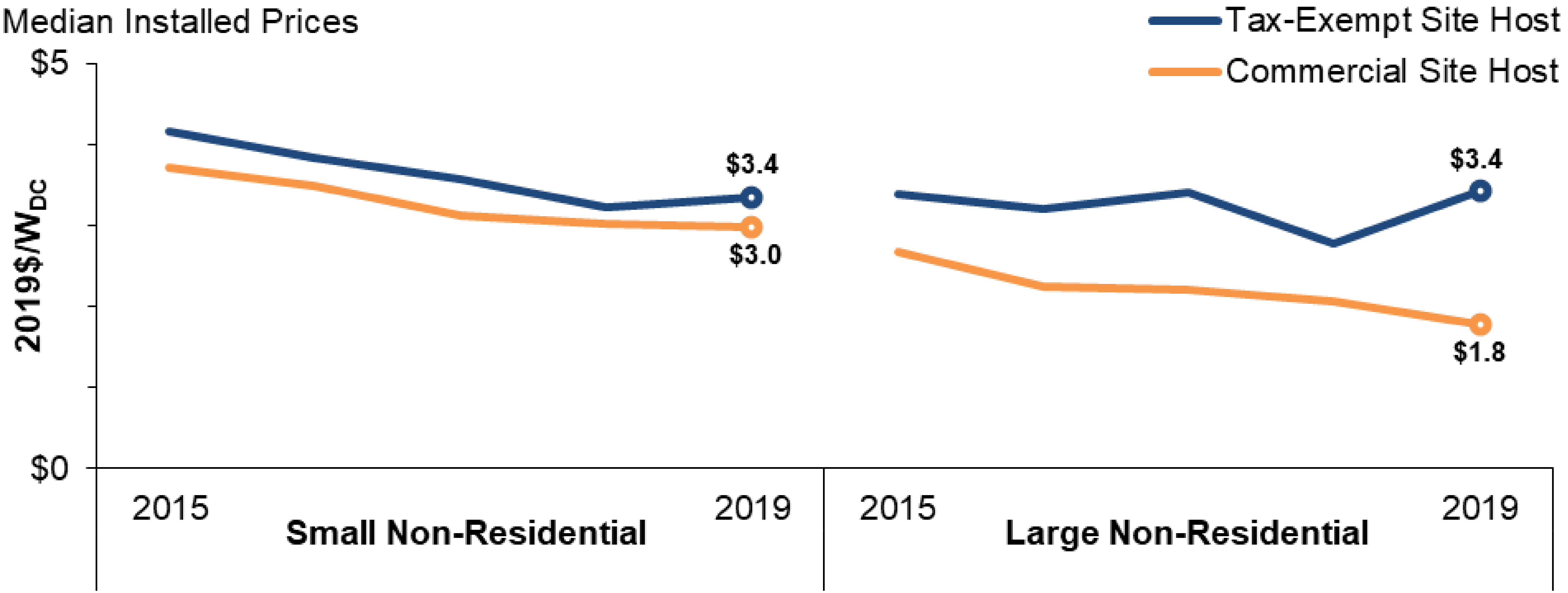


Installed Price Trends by Inverter Type



Notes: MLPE refers to Module Level Power Electronics (either a microinverter or DC optimizer). Data shown only if at least 20 observations available (impacting the trend line for large non-residential systems with microinverters).

Installed Price Differences for Commercial vs. Tax-Exempt Customers



Notes: Tax-Exempt site hosts includes government, schools, and non-profits.

For more information

Download summary data tables and public data file:
http://trackingthesun.lbl.gov

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Appendix: Data Sources and Methods

Data Sources

Project-level data

- Provided by state agencies and utilities that administer PV incentive programs, renewable energy credit registration (REC) systems, or interconnection processes
- Some of these data already exist in the public domain (e.g., California's Currently Interconnected Dataset), though LBNL may receive supplementary fields, in some cases covered under non-disclosure agreements

66 entities spanning 31 states have contributed data

- See next slide for a list of these entities

Data sources have evolved over time, as incentive programs have phased out

- In many cases, utilities and PUCs have opted to continue data collection through other channels

List of Entities Contributing Data

AR State Energy Office
AZ Ajo Improvement Company
AZ Arizona Public Service
AZ Duncan Valley Electric Cooperative
AZ Mohave Electric Cooperative
AZ Morenci Water and Electric
AZ Navopache Electric Cooperative
AZ Salt River Project
AZ Sulfur Springs Valley Electric Cooperative
AZ Trico Electric Cooperative
AZ Tucson Electric Power
AZ UniSource Energy Services
CA Public Utilities Commission
CA Center for Sustainable Energy (Bear Valley Electric)
CA Center for Sustainable Energy (PacifiCorp)
CA City of Palo Alto Utilities
CA Imperial Irrigation District
CA Los Angeles Department of Water & Power
CA Sacramento Municipal Utility District
CO Xcel Energy/Public Service Company of Colorado
CT Green Bank
CT Public Utilities Regulatory Authority
DC Public Service Commission
DE Dept. of Natural Resources and Env. Control
FL Energy & Climate Commission
FL Gainesville Regional Utilities
FL Orlando Utilities Commission
IL Department of Commerce & Economic Opportunity
IL Power Agency
KS Evergy
KS Westar Energy, Inc.
MA DOER
MA Clean Energy Center
MD Energy Administration
ME Efficiency Maine
MN Department of Commerce
MN Xcel Energy/Northern States Power
MO Ameren
MO Evergy
NC Sustainable Energy Association
NH Public Utilities Commission
NJ Board of Public Utilities
NM Energy, Minerals and Natural Resources Department
NM Public Service Company of New Mexico
NM Xcel Energy
NV NV Energy
NY State Energy Research and Development Authority
OH Public Utilities Commission
OR Energy Trust of Oregon
OR Department of Energy
OR PacifiCorp
PA Dept. of Community and Economic Development
PA Department of Environmental Protection
PA Sustainable Development Fund
RI National Grid
RI Commerce Corporation
TX Austin Energy
TX CPS Energy
TX Frontier Associates
UT Office of Energy Development
VA Department of Mines, Minerals and Energy
VT Energy Action Network
VT Energy Investment Corporation
WA Puget Sound Energy
WA Washington State University
WI Focus on Energy

Key Definitions and Conventions

Customer Segments

- **Residential:** Single-family and, depending on the data provider, may also include multi-family
- **Small Non-Residential:** Non-residential systems ≤100 kW_{DC}
- **Large Non-Residential:** Non-residential systems >100 kW_{DC} (and ≤5,000 kW_{AC} if ground-mounted)

** Independent of whether connected to the customer- or utility-side of the meter*

Units

- Real 2019 dollars
- Direct current (DC) Watts (W), unless otherwise noted

Installed Price: Up-front $/W price paid by the PV system owner, prior to incentives

Sample Frames and Data Cleaning

Full Sample

Used to describe system characteristics

The basis for the public dataset

1. Remove systems with missing size or install date
2. Standardize installer, module, inverter names
3. Integrate equipment spec sheet data
   – Module efficiency and technology type
   – Inverter power rating
   – Flag microinverters or DC optimizers
4. Convert dollar and kW values to appropriate units, and compute other derived fields

Installed-Price Sample

Used in analysis of installed prices

5. Remove systems if:
   – Missing installed price data
   – Third-party owned (TPO)
   – Battery storage included
   – System expansion
   – Self-installed

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 8

Responding Witness: William Steven Seelye

Q-8. Refer to the Supplemental Seelye Testimony, page 10, lines 5–11.

a. Explain how LG&E distinguished variable transmission losses from core transmission losses.

b. Provide the percentage of total losses accounted for by each type of loss.

c. Provide all workpapers, engineering studies, and calculations that substantiate this estimate and identify the page number or location of the relevant information.

A-8.

a. The Companies' loss studies distinguished variable transmission from fixed transmission losses. Variable transmission losses consist of I^2R losses and fixed losses consist of transformer core losses and conductor fixed losses. The methodologies used to distinguish between variable and fixed losses are described in detail in the loss studies provided in the attachment to the response to PSC 5-20 for KU and the attachment to the response to PSC 5-21 for LG&E.

b. For KU, the breakdown between fixed and variable costs is shown on Page 25 of 51 of the attachment to KU's Response to PSC 5-20. For LG&E, the breakdown between fixed and variable costs is shown on Page 25 of 51 of the attachment to LG&E's Response to PSC 5-21.

c. See the responses to parts a and b.

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Case No. 2020-00350

Question No. 9

Responding Witness: William Steven Seelye

Q-9. Refer to the Supplemental Seelye Testimony, page 11, lines 2–4. Explain if LG&E agrees whether it is also true that line losses incurred to serve customer load vary by location, even when taking service at the same voltage level of the distribution system. If yes, explain why LG&E does not charge customer locational specific rates for line losses. If not, provide quantitative justification to support the assertion.

A-9. Mr. Seelye agrees that line losses in general depend on location. LG&E does not charge customer locational specific rates for line losses for the same reason it does not charge specific rates for any number of other differences in costs to serve customers in the same rate class; namely, it minimizes customer confusion and increases administrative efficiency to group reasonably equivalently situated customers in the same rate class and charge the same rates to all, understanding that some intra-class subsidies inevitably result from that approach.

But the distribution loss profile is far more complex for net metering customers. Because customer-generators supply power to the grid, the losses created by the energy the customer-generators supply to the grid would vary much more by location than losses for retail sales customers. Traditionally, the energy received by retail sales customers would have to be transmitted through transmission facilities, transmission and distribution substations, primary lines, transformers, and customer services. Therefore, there would be greater homogeneity for losses involved in providing service to retail sales customers than for customer-generators. Because energy supplied by customer-generators will utilize diverse distribution facilities and potentially create bottlenecks on the distribution system, there would be greater heterogeneity for the losses created by the energy that customer-generators supply to the grid. The Companies' distribution systems were planned to provide retail sales service to customers; therefore, the systems were designed to deliver energy to customers while minimizing line losses. The distribution systems were not designed to receive energy from customer-generators and deliver that energy to other customers on the system. Utilizing the distribution system for purposes for which it was not designed could result in the overloading of equipment and the creation of line losses not the avoidance of line losses.

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Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 10

Responding Witness: William Steven Seelye

Q-10. Refer to the Supplemental Seelye Testimony, page 11, lines 5–7. Explain why, and provide a quantitative example in support of, reducing total energy supplied from a bulk power/centralized generator would not reduce total line losses, including core and load losses, at the customer meter.

A-10. The cited testimony does not assert that "reducing total energy supplied from a bulk power/centralized generator would not reduce total line losses, including core and load losses, at the customer meter"; rather, Mr. Seelye's testimony states at lines 4-7 of page 11:

> As I explained above, for the transmission system, it is only possible to avoid I^2R losses. Because they are fixed, it is unreasonable to assume that core losses on the transmission system could be avoided by energy supplied to the grid by customer-generators.

Therefore, Mr. Seelye did not state that "reducing total energy supplied from a bulk power/centralized generator would not reduce total line losses"; rather, his testimony states there is a limited possibility of avoiding I^2R losses. But core losses are not avoidable by energy production from distributed generation precisely because such losses do not vary with a transformer's loading.[4]

[4] *See, e.g.,* Lovorn, Kenneth L., "Transformer efficiency: Minimizing transformer losses," Consulting-Specifying Engineer, June 12, 2013 ("[C]ore losses consist of those generated by energizing the laminated steel core. These losses are virtually constant from no-load to full-load, and for the typical 150 C rise transformer are about 0.5% of the transformer's full-load rating."), *available at* https://www.csemag.com/articles/transformer-efficiency-minimizing-transformer-losses/.

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Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 11

Responding Witness: William Steven Seelye

Q-11. Refer to the Supplemental Seelye Testimony, page 11, footnotes 8 and 9.

a. Explain each step of the calculation in each footnote, and explain the source of each number used in the calculation.

b. Clarify exactly which electronic page of the referenced 2010 Analysis of System Losses from LG&E's response to Commission Staff's Fifth Request for Information (Staff's Fifth Request), Item 20, corresponds to each number in the calculation

A-11. a. Footnote 8 calculates the variable transmission energy loss factor for KU. The variable transmission energy loss factor is calculated from KU's Loss Study by multiplying the transmission energy loss factor by the ratio of (a) the percentage of variable transmission losses to total losses to (b) the percentage of total transmission losses to the percentage of total transmission losses to total losses. For footnote 8, the 2.8227% was obtained from Page 5 of 51 of the attachment to KU's response to PSC 5-20. The 71.2% was obtained from Page 25 of 51 of the attachment to KU's Response to PSC 5-20. The 78.5% was obtained from Page 25 of 51 of the attachment to KU's response to PSC 5-20.

Footnote 9 calculates the variable transmission energy loss factor for LG&E. The variable transmission energy loss factor is calculated from LG&E's Loss Study by multiplying the transmission energy loss factor by the ratio of (a) the percentage of variable transmission losses to total losses to (b) the percentage of total transmission losses to the percentage of total transmission losses to total losses. For footnote 9, the 1.033% was obtained from obtained from Page 5 of 51 of the attachment to LG&E's response to PSC 5-21. The 16.8% was obtained from Page 25 of 51 of the attachment to LG&E's response to PSC 5-21. The 21.5% was obtained from Page 25 of 51 of the attachment to LG&E's response to PSC 5-21.

b. See the response to part a.

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Question No. 12

Responding Witness: William Steven Seelye

Q-12. Refer to the Supplemental Seelye Testimony, page 12, footnotes 10 and 11.

a. Explain each step of the calculation in each footnote and explain the source of each number used in the calculation.

b. Clarify exactly which electronic page of the referenced 2010 Analysis of System Losses from LG&E's response to Staff's Fifth Request, Item 20, corresponds to each number in the calculation.

A-12.

a. Footnote 10 calculates the variable loss factor on KU's primary distribution system associated with energy supplied to the grid by customer generators. Footnote 10 is calculated from KU's Loss Study by multiplying total primary system losses by a factor of 80% representative of the percentage of variable losses on the primary system and a factor of 90%, which assumes that only 10% of the energy supplied by customer-generators would be transmitted across the primary system and the remaining 90% would be transmitted across the secondary system. For footnote 10, the 2.8227% and 5.011% were obtained from Page 5 of 51 of the attachment to KU's response to PSC 5-20. See also the responses to Question Nos. 13 and 14.

   Footnote 11 calculates the variable loss factor on LG&E's primary distribution system associated with energy supplied to the grid by customer generators. Footnote 11 is calculated from LG&E's Loss Study by multiplying total primary system losses by a factor of 80% representative of the percentage of variable losses on the primary system and a factor of 90%, which assumes that only 10% of the energy supplied by customer-generators would be transmitted across the primary system and the remaining 90% would be transmitted across the secondary system. For footnote 11, the 1.033% and 2.998% were obtained from Page 5 of 51 of the attachment to LG&E's response to PSC 5-21. See also the responses to Question Nos. 13 and 14.

b. See the response to part a.

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Response to Commission Staff's Seventh Request for Information
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Question No. 13

Responding Witness: William Steven Seelye

Q-13. Refer to the Supplemental Seelye Testimony, page 12, lines 3–4. Explain how LG&E determined that distribution variable losses represent 80 percent of total primary line losses. Provide all workpapers, engineering studies, and calculations that substantiate this estimate and identify the page number or location of the relevant information.

A-13. The 80% for variable losses is based on Mr. Seelye's experience working with loss studies for electric utilities. The Companies' loss studies did not explicitly state the percentage of variable losses to total for primary line losses. However, for transmission the percentage was 90.7% for KU and LG&E. It has been Mr. Seelye's experience that the percentage of fixed losses on the primary system is higher because of greater prevalence of transformers on the primary system compared to the transmission system.

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Case No. 2020-00350

Question No. 14

Responding Witness: William Steven Seelye

Q-14. Refer to the Supplemental Seelye Testimony, page 12, lines 3–8. Explain how LG&E determined that 10 percent of the energy delivered by customer-generators would be transmitted through the primary system. Provide all workpapers, engineering studies, and calculations that substantiate this estimate.

A-14. The 10 percent estimate is based on an assumption that a small amount of energy supplied to the grid by customer-generators would flow through the primary system. The percentage could be higher, resulting in lower avoided primary distribution losses. Both the 80% and the 90% assumptions in the calculation are based on the principle that energy supplied to the grid could, at a maximum, avoid most of the losses on the primary system. The small amount of distributed generation on KU and LG&E's system has simply not justified performing a costly loss study for the purpose of estimating the primary voltage losses that could be *avoided or created* by the energy supplied to the grid by customer-generators.

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Response to Commission Staff's Seventh Request for Information
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Question No. 15

Responding Witness: William Steven Seelye

Q-15. Refer to the Supplemental Seelye Testimony, page 13, Section IV, Avoided Ancillary Service Cost.

a. Explain why LG&E chose to use the ancillary service charges set forth in LG&E's Open Access Transmission Tariff for the ancillary service cost component.

b. Explain why alternative compensation amounts were not provided for certain schedules.

A-15.

a. To be clear, Mr. Seelye is not proposing to include avoided costs related to ancillary services. But if ancillary services are included as avoided costs, then they should be based on the filed ancillary service rates for KU and LG&E that have been approved by the Federal Energy Regulatory Commission (FERC). It would be unreasonable to use filed rates for some other utility or group of utilities, such as the ancillary service rates applicable in PJM. Neither KU nor LG&E is a member of PJM. The ancillary service rates for PJM have no applicability to the ancillary service rates charged by the Companies. The ancillary service rates in PJM are based on a market design that does not apply to KU and LG&E. The rates and costs applicable to a wholesale market design, such as the PJM market, in which the Companies do not participate, cannot be attributed KU and LG&E. Furthermore, it is unclear why the rates from PJM should be imputed instead of the rates from some other energy market, such as MISO. It is unclear why PJM is given a privileged position.

b. Mr. Seelye discussed three alternatives for certain ancillary services: (1) a value of zero could be used, which is Mr. Seelye's recommended approach, (2) the filed ancillary service rates approved by the FERC could be used, (3) the ancillary service percentages set forth in the FERC-approved open access transmission tariff could be applied to the Companies' avoided capacity cost to determine the associated avoided costs of ancillary services. In the table shown on page 30 of Mr. Seelye's Supplemental Testimony, the values for the first alternative and the third alternative are shown in the table. Mr. Seelye did not provide the second alternative because it would correspond to embedded costs as opposed to avoided costs. The table shown on page 30 of Mr. Seelye's Supplemental Testimony are reflective of avoided costs, specifically a low-case avoided cost of zero and a high-case avoided cost of $0.00006 for both KU and LG&E.

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Question No. 16

Responding Witness: William Steven Seelye

Q-16. Refer to the Supplemental Seelye Testimony, page 22, lines 19–21. Provide all the options offered by LG&E that allow residential and commercial customers to provide legally enforceable firm energy and/or capacity to LG&E. For each offering, provide the number of customers that are currently participating, the total annual energy and capacity enrolled for the past three years, and compensation received for energy and capacity. Provide in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-16. The only option currently available for residential and commercial customers to provide legally enforceable firm energy and capacity is Rate LQF. LQF would not generally be applicable to residential distributed generation facilities. The Companies are proposing to modify Rates SQF and LQF in these proceedings to provide greater flexibility to customers. See the Supplemental Testimony of Robert M. Conroy and David S. Sinclair.

The vast majority of the Companies' net metering customers have fixed-tilt solar facilities, most of which are roof-top solar installations that do not provide legally enforceable energy and capacity. See the response to Question No. 2. Also see KU's response to MA-KFTC-KSES 1-1(d) and LG&E's response to MHC-KFTC-KSES 1-1(d).

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Question No. 17

Responding Witness: William Steven Seelye

Q-17. Refer to the Supplemental Seelye Testimony, page 23, lines 3–5. Explain why LG&E would need assurance that any capacity provided by a customer-generator would be in place and operational for 20 years or more. Provide all workpapers, calculations, planning documents, or financial models that informed the number of 20 years.

A-17. Assuming that the Companies do not have a generation capacity need until the year 2028, a contract term providing capacity for a period less than 7 years would result in zero avoided capacity costs. The following table shows the current avoided cost for fixed-tilt solar for contract terms ranging from a contract term of one year to a contract term of 20 years for a contract beginning in 2022:

Levelized Avoided Costs per kWh for Fixed Tilt Solar Based on Term Shown With Contract Beginning 2022			
Contract Term	End of Contract	Number of Years of Term Satisfying Capacity Need	Levelized Avoided Cost per kWh
1	2022	0	$0.00000/kWh
2	2023	0	$0.00000/kWh
3	2024	0	$0.00000/kWh
4	2025	0	$0.00000/kWh
5	2026	0	$0.00000/kWh
6	2027	0	$0.00000/kWh
7	2028	1	$0.00084/kWh
8	2029	2	$0.00117/kWh
9	2030	3	$0.00138/kWh
10	2031	4	$0.00150/kWh
11	2032	5	$0.00156/kWh
12	2033	6	$0.00160/kWh
13	2034	7	$0.00162/kWh
14	2035	8	$0.00162/kWh
15	2036	9	$0.00161/kWh
16	2037	10	$0.00161/kWh
17	2038	11	$0.00163/kWh
18	2039	12	$0.00169/kWh
19	2040	13	$0.00175/kWh
20	2041	14	$0.00181/kWh

As can be seen from this table, no avoided capacity costs would be produced from contracts with contract terms less than seven years, with the avoided costs increasing thereafter with the length of the contract term. The spreadsheet used to produce the table is attached.

The attachment is being provided in a separate file in Excel format.

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Question No. 18

Responding Witness: William Steven Seelye

Q-18. Refer to the Supplemental Seelye Testimony, page 23, lines 12–14. Provide each net metering tariff throughout the United States that compensates customers for export at a rate (1) less than or equal to solar purchased power agreements, and (2) greater than solar purchased power agreements. For each tariff, provide the applicable commission order with line citations that support that position.

A-18. Mr. Seelye has not performed such a comprehensive review, which would require an extensive data collection and analysis effort. See also the Companies' response to KSIA 7-11.

But Mr. Seelye disagrees with the premise of the question, namely that the net metering tariffs of utilities, particularly those in other states, should be relevant to how this Commission should set NMS-2 compensation rates for these utilities. Other states can and do have different statutory law governing net metering, which would likely affect the rates stated in the tariffs of utilities in those states.

Moreover, this Commission has stated clearly for decades that utilities are obligated to provide service at the lowest reasonable cost. Indeed, more than 30 years ago the Commission characterized this obligation as a statutory imperative: "LG&E has a statutory obligation under KRS 278.030 to serve its customers at the lowest reasonable cost."[5] In the Companies' recent proceeding regarding its Solar PPA, the Commission stated, "[O]ne of the Commission's 'most important roles' in administering KRS Chapter 278, 'is to provide the lowest possible cost to the rate payer.'"[6] Therefore, what is relevant in these proceedings is what is a fair, just, and reasonable NMS-2 compensation rate for *all* customers—not just NMS-2 customers—that is consistent with the Companies' obligation to provide service at the lowest reasonable cost. It is Mr. Seelye's view that determining NMS-2 compensation consistent with lowest reasonable cost principles must take

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[5] *An Investigation of Electric Rates of Louisville Gas and Electric Company to Implement a 25 Percent Disallowance of Trimble County Unit No. 1*, Case No. 10320, Order at 19 (Ky. PSC Oct. 2, 1989).
[6] Case No. 2020-00016, Order at 7 (PSC Ky. Dec. 16, 2020), *quoting Public Service Comm'n v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986) ("The Commission has ignored one of its most important roles, which
is to provide the lowest possible cost to the rate payer.").

into account what the *exact same product*, i.e., solar energy, can be purchased for in the market, which makes solar PPA pricing crucial in considering NMS-2 rates.

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Question No. 19

Responding Witness: David S. Sinclair

Q-19. Refer to the Supplemental Seelye Testimony, page 23, lines 18–19. Provide the contract for the referenced PPA.

A-19. The referenced PPA was previously provided as Rebuttal Exhibit RMC-1 to the Rebuttal Testimony of Robert M. Conroy in this proceeding. The PPA sets forth a purchase rate of all energy and capacity from the solar facilities at a 20-year fixed price of $0.02782/kWh and provides all renewable energy certificates to the Companies, which the Companies currently plan to sell to offset some of the PPA cost.

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Question No. 20

Responding Witness: Elizabeth J. McFarland / William Steven Seelye

Q-20. Refer to the Supplemental Seelye Testimony, page 26.

a. Explain whether LG&E's projected 2022 through 2031 total transmission plant additions for retail load growth include (1) transmission expansions -8- Case No. 2020-00350 that may be need for new generation or (2) any federal policy than may be adopted in over the projected period.

b. Explain if, by only focusing on transmission plant additions needed for retail load growth, LG&E is suggesting that non-wires transmission alternatives cannot be partly enabled through distributed energy resources, including distributed generation. Provide support for the assertion.

c. Provide all research and internal documents that LG&E has for developing and implementing a non-wires transmission alternatives framework.

A-20.

a. The capacity related transmission investments provided in Seelye Testimony, page 26 do not include transmission projects for new generation nor any federal policy that may be adopted in over the projected period.

b. By "non-wires transmission" it is assumed that the phrase refers to utilizing distributed generation at the distribution level instead of relying on the transmission system to transmit energy from central power stations to the distribution system.

   The Companies are not suggesting that distributed generation supplied at the distribution system could never in theory displace future transmission plant investments. The assertion being made in Mr. Seelye's testimony is that because of the generally declining demands on KU and LG&E's system, the Companies generally have adequate transmission capacity to serve any localized load growth on their systems. The modest plant additions necessary for load growth are isolated to specific areas of the system. It is virtually impossible that energy supplied to the grid from customer-generators can or will result in the Companies' planned transmission additions being avoided.

If the Companies were required to make significant plant additions for future load growth, then it theoretically would be possible for large amounts of distributed generation to avoid transmission capacity, but that is simply not the case for KU and LG&E; notably, there is a 1% of annual peak load statutory cap on net metering capacity,[7] as well as a 15% peak load cap on each line section of a radial distribution circuit under the Commission's Net Metering Interconnection Guidelines.[8] Also, the Companies' peak demands are generally declining and the Companies are planning very little plant additions to accommodate localized growth on the system.

c. The low demand growth on KU and LG&E's systems and the limited amount of distributed generation on the Companies' systems have not justified spending the resources to conduct such a study.

[7] KRS 278.466(1).
[8] *Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity Up to Thirty Kilowatts*, Admin. Case No. 2008-00169, Order Appx. A at 3 (Ky. PSC Jan. 8, 2009).

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Case No. 2020-00350

Question No. 21

Responding Witness: John K. Wolfe / William Steven Seelye

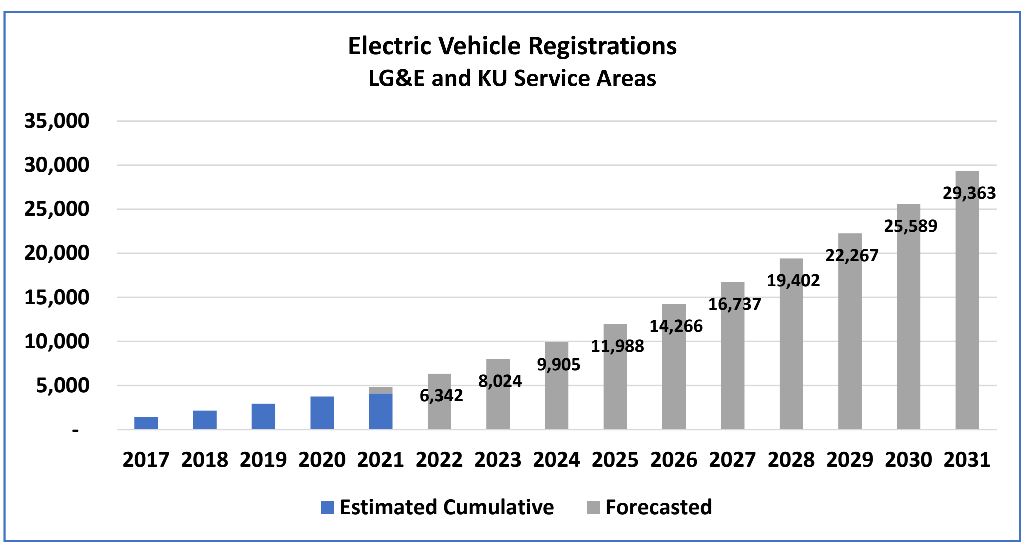
Q-21. Refer to the Supplemental Seelye Testimony, page 27.

a. Provide the assumptions related to electric vehicle growth within both service territories and how much of the total distribution plant addition estimates are related to electric vehicle growth over the 2022 through 2031 period.

b. Provide all research and internal documents LG&E has for developing and implementing a non-wires distribution alternatives framework.

A-21.

a. The Companies track monthly EV registrations through a partnership with the Electric Power Research Institute. This data, along with forecasted battery prices and a comparison of EV costs to internal combustion engine vehicle (ICE) costs, is used to develop a forecast of EV growth for the Companies' service area based on the historical proportion of EV sales to total new car sales and the EV to ICE cost ratio. This forecast assumes that historical trends in EV adoption continue (see table below).



Distribution plant additions or upgrades associated with growth of electric vehicle adoption in the LG&E and KU service areas have been negligible to date and are forecasted to have negligible impacts over the Companies' 2021-2025 business plan horizon. Meaningful plant additions and upgrades are not expected to occur until greater geographical clustering of electric vehicle ownership occurs in the LG&E and KU service areas. Grid impacts are challenging to ascertain and will be dependent on the location of clustering, type and timing of charging adopted by customers, and the load and physical characteristics of nearby distribution components.

b. The Companies participate in multiple industry forums and have access to numerous industry studies which review potential frameworks for integrating distributed energy resources into the distribution grid and leveraging these resources and other non-wires alternatives to help avoid or defer traditional capital investments to satisfy capacity and reliability needs of the distribution grid. Examples of publicly available studies are attached. Also, the Companies performed a case study for using solar and storage to meet 100% of the electricity requirements for a distribution circuit (LG&E's Highland 1103 circuit). The results from this study is also attached.

Historically, the Companies have utilized non-wires alternatives (NWA) to reduce distribution system constraints and defer or avoid capital investments. For example, the Companies' Distribution System Operators (DSO) monitor the performance of the grid and when constraints occur, shift load to other non-congested circuits when switching capabilities are available. This is a normal practice, and the Companies continue to emphasize circuit ties that provide these flexibilities versus upgrading distribution infrastructure unnecessarily.

The Companies' energy efficiency efforts have helped reduce overall load across the system which has limited the need for some capacity related investments. The Distribution System Planning organization uses a robust modeling tool which provides electrical simulation models and analyses of LGE-KU's power distribution system. This analysis results in the annual forecast and is adjusted based on the loading of transformers and thermal ratings of conductor. Capacity related projects are then re-evaluated each year to ensure load meets the criteria that justifies the capacity related investment.

Also, the Company now has time-of-day rates for residential and general service customers. These rates are designed to give customers a clear incentive to move their demands from peak periods to periods of lower demand. Such rates are a non-wires approach to addressing distribution system needs through reducing peak loads and system capacity needs.

THE NON-WIRES SOLUTIONS IMPLEMENTATION PLAYBOOK

A PRACTICAL GUIDE FOR REGULATORS, UTILITIES, AND DEVELOPERS

BY MARK DYSON, JASON PRINCE, LAUREN SHWISBERG, AND JEFF WALLER

ABOUT US

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

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US Climate Alliance

WSGR
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Wilson Sonsini Goodrich & Rosati

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Green Mountain Power
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Pacific Gas & Electric
Regulatory Assistance Project
Rhode Island Office of Energy Resources
Southern California Edison
Stoel Rives LLP
Strategen
Sunrun
Tendril
Vote Solar
Wood Mackenzie

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The dynamics of today's electric grid do not ensure that energy is efficiently distributed or that capital is efficiently allocated. Increasingly, portfolios of distributed energy resources (DERs)—also known as non-wires solutions (NWS)—can address these current inefficiencies by solving grid needs more cost-effectively than business-as-usual approaches to traditional infrastructure investment.

NWS are applications of DERs in specific locations that defer or eliminate an investment in traditional and costlier "wires-and-poles" infrastructure. In addition to deferring or avoiding more expensive traditional investments and providing reliable electric service, NWS can deliver ratepayers cost savings and support the integration of smart, customer-centered technologies that promote a cleaner, more flexible, and more resilient grid. However, despite these clear benefits, three key barriers have hampered widespread non-wires solution deployment: regulatory environments are not appropriately designed to encourage NWS, utility standard operating procedures do not systematically consider NWS, and procurement practices need to be refined to more effectively source NWS.

To help overcome these barriers and capture the compelling benefits NWS can provide, Rocky Mountain Institute created this *Non-Wires Solutions Implementation Playbook* to delineate innovative approaches to spur non-wires solution adoption and recommend planning and operational strategies to improve non-wires solution processes.

Utility investment in distribution infrastructure is big business

Since 2006, regulated utilities across the US have invested $55 billion each year, on average, in distribution, transmission, and generation infrastructure.[1] Historically, distribution infrastructure has represented the greatest share of utilities' expenditures as utilities seek to maintain and modernize extensive last-mile networks to serve hundreds of millions of electricity end-users.

Utilities have an incentive to make these investments because they are entitled to earn a regulator-approved rate of return on the capital expenditures that are included in their rate base (e.g., power plants, distribution lines, transformers). Even as electricity sales and peak demand have stayed flat in recent years, utility investments added to the rate base have increased. The rising ratio of utility distribution assets per customer raises concerns that rates may increase as the cost of distribution investments are passed through to customers for years to come.[2] To mitigate this risk, it is critical that grid investment decisions are prudent and result in the most cost-effective solutions.

Distributed energy resources can be used as non-wires solutions to save ratepayers money

Utilities and regulators can adapt existing planning processes in order to consider all possible solutions when making investments to address grid needs. Specifically, by taking advantage of the proliferation of distributed energy resources (DERs) and energy management software solutions, planning processes can ensure grid services are provided by the most cost-effective options, and provide safe, reliable electric service for customers.

For the purposes of this report, we define DERs to include the range of demand- and supply-side software and hardware resources that generate electricity or control loads and can be deployed throughout low-voltage electric distribution systems to meet energy and reliability needs. Common demand-side DERs include energy efficiency measures that reduce loads, and demand response mechanisms to regulate loads by generating electricity or otherwise reducing demand. Typical supply-side DERs are distributed generation technologies like rooftop or community-scale solar PV and combined heat and power systems. Energy storage resources like batteries are DERs that can act as both demand- and supply-side resources by serving as either load or generation as needed. Any of these DERs can be installed on the customer or utility side of the meter, and can be owned by the user, a third party, or the utility. When DERs are used to solve grid needs that would have otherwise required traditional utility infrastructure, they can be considered non-wires solutions (NWS). NWS are applications of DERs in specific locations that defer or eliminate an investment in traditional and costlier "wires-and-poles" infrastructure. NWS have also been called non-wires alternatives (NWA), which implies that they will be evaluated as alternatives to wires-and-poles infrastructure. In contrast, the terminology of "non-wires solutions" institutionalizes NWS as part of the utility's standard solution toolkit, indicating that they should be considered as part of a basic set of options.

Non-wires solutions provide a host of benefits and should be a key component of innovative distribution planning processes

States and utilities can incorporate NWS into distribution-level grid modernization and integrated planning efforts that are increasingly taking place across the nation. In addition to cost savings, the effective integration of NWS into planning processes can help capture the range of benefits that DERs and NWS provide, including:

- Ratepayer cost savings
- Flexibility for planning processes
- Progress toward clean energy goals
- Opportunities to test new utility business models
- Local economic development
- Job creation

To scale NWS several important market barriers must be addressed

Despite these myriad benefits, markets for NWS remain nascent. Although utilities across the nation spend tens of billions of dollars each year on distribution infrastructure, only a few have pursued NWS at scale. This sluggish uptake is due to a number of barriers, including:

- Regulatory frameworks that do not always encourage NWS
- Limited utility processes and expertise around NWS
- Limited procurement experience, which inhibits competitive non-wires solution proposals

Compounding these barriers, there is a need for coordination between four key sets of stakeholders to support NWS market development. Legislators, regulators, utilities, and developers have the opportunity to take on distinct—and overlapping—roles and responsibilities to establish, cultivate, and guide the NWS market. Legislatures can choose to play a key role in the earlier stages of NWS market development, but collaboration from the other three stakeholder groups is critical throughout the entire NWS life cycle.

This Implementation Playbook can help overcome barriers and scale the NWS market

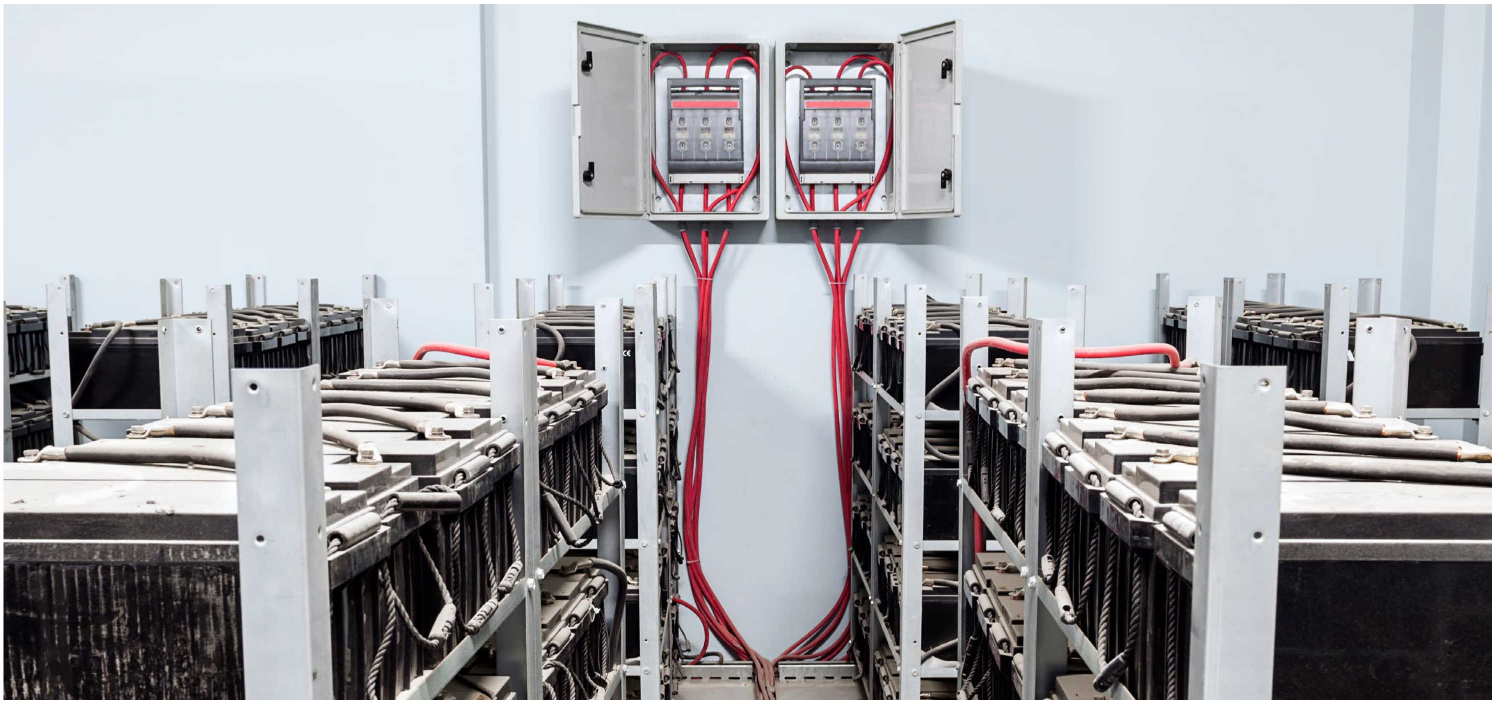
This Playbook seeks to address the barriers to NWS and catalyze deployment across the nation. It draws upon interviews conducted with more than 65 experts across 15 states, including over 20 utilities, as well as developers, regulators, and trade associations. The intent is to provide a common set of recommendations that any jurisdiction can build upon to directly implement and scale NWS.

The Playbook is composed of two sections: (1) a best practice framework and (2) implementation guidelines. The first section details best practices that underpin the three key elements that are critical for creating and sustaining successful NWS programs: establishing a supportive regulatory environment, integrating NWS into standard utility operating procedures, and creating a holistic process for NWS procurement. While the Playbook cites many examples drawn from NWS experiences in New York and California, the recommended best practices are applicable nationwide. Because every jurisdiction will need to adapt these recommendations to suit local circumstances, we provide guidance on how these recommendations can be applied in different contexts, including under different types of utilities: vertically integrated; wires-only; and consumer-owned and other nonprofit entities, such as cooperative and municipal utilities.

Section 2 provides practical implementation guidelines for the four key components underpinning non-wires solution implementation: screening criteria, competitive solicitation processes, evaluation frameworks, and contracting considerations.

The market for NWS is nascent but represents a promising opportunity for reducing customer costs and enabling a lower-carbon electricity grid. With the increase in spending on distribution infrastructure, there is a pressing need to turn to approaches like NWS to minimize the impact on customer bills. At the same time, NWS can unlock additional value from DERs while both reducing net system costs and promoting the cost-effective deployment of resources that are important for reducing CO_2 emissions.

Pursuing NWS today can help to further develop best practices, highlight the most valuable opportunities for non-traditional solutions, and prove the case for a more uniform, comprehensive market for NWS in the future. This report lays out best practices and provides practical guidance for developing key elements needed for implementation. It also highlights areas for future exploration as the market evolves. To further scale NWS by proving out the broader case for its application, there is a pressing need for more coordinated efforts to build on the lessons learned and find least-cost, best-fit solutions and processes that work across the wide variety of utilities and states that stand to gain.



THE SCALE OF THE NWS OPPORTUNITY IN A CHANGING GRID

Non-wires solutions can improve the system benefits of DER deployments to help realize savings of both dollars and emissions across the US

Directly capturing the distribution-level benefits (e.g., distribution capacity deferral value[3]) of DERs at the project level via a non-wires solution can improve system value of energy efficiency and demand flexibility measures by 30%, and battery storage by over 100%. In many cases, DERs are even cost-effective when only evaluated based on avoided generation costs. Using an average value of peak reduction for transmission and distribution,[4] we find that the additional, distribution-level avoided costs associated with the DER scenario are approximately $17 billion through 2030.

Additionally, increasing DER deployment can provide carbon emissions reductions via both direct and indirect mechanisms.[5] DERs can help realize direct carbon reductions by avoiding carbon-intensive electricity generation on the bulk power system, and can also enable indirect carbon savings by providing flexibility. As a conservative forecast, our analysis suggests that enabling distribution system revenue via NWS, scaled nationally, could avoid approximately 300 MT CO_2 over an assumed 20-year lifetime of DER assets.

INTRODUCTION

INTRODUCTION

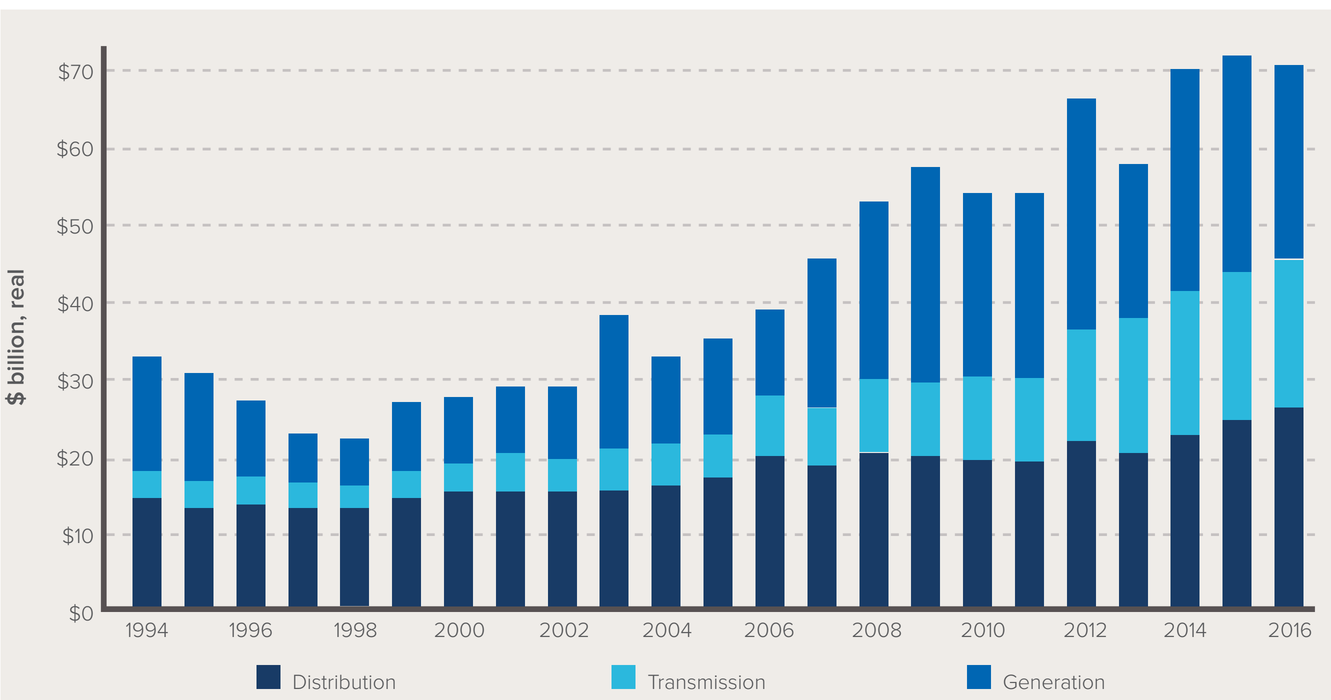
The dynamics of today's electric grid do not ensure that energy is efficiently distributed or that capital is efficiently allocated. Increasingly, portfolios of distributed energy resources (DERs)—known as non-wires solutions (NWS)—can address these inefficiencies by solving grid needs more cost-effectively than business-as-usual approaches to traditional infrastructure investment. NWS are applications of DERs in specific locations that defer or eliminate an investment in traditional and costlier "wires-and-poles" infrastructure solutions. In addition to ensuring deferring or avoiding these more expensive traditional investments and providing reliable electric service, NWS can deliver ratepayers cost savings and support the integration of smart, customer-centered technologies that promote a cleaner, more flexible, and more resilient grid. Despite these clear benefits, three key barriers have hampered widespread non-wires solution deployment: regulatory environments are not appropriately designed to encourage NWS, utility standard operating procedures do not systematically consider NWS, and procurement practices need to be refined to more effectively source NWS. To help overcome these barriers and capture the compelling benefits NWS can provide, Rocky Mountain Institute created this *Non-Wires Solution Implementation Playbook* to delineate innovative approaches to spur non-wires solution adoption and to recommend planning and operational strategies to improve non-wires solution processes.

Utility investment in distribution infrastructure is big business

Since 2006, regulated utilities across the US have invested on average $55 billion each year in distribution, transmission, and generation infrastructure.[6] Historically, distribution infrastructure has represented the greatest share of spending as utilities seek to maintain and modernize extensive last-mile networks to serve

FIGURE 1

US REGULATED UTILITY INVESTMENT

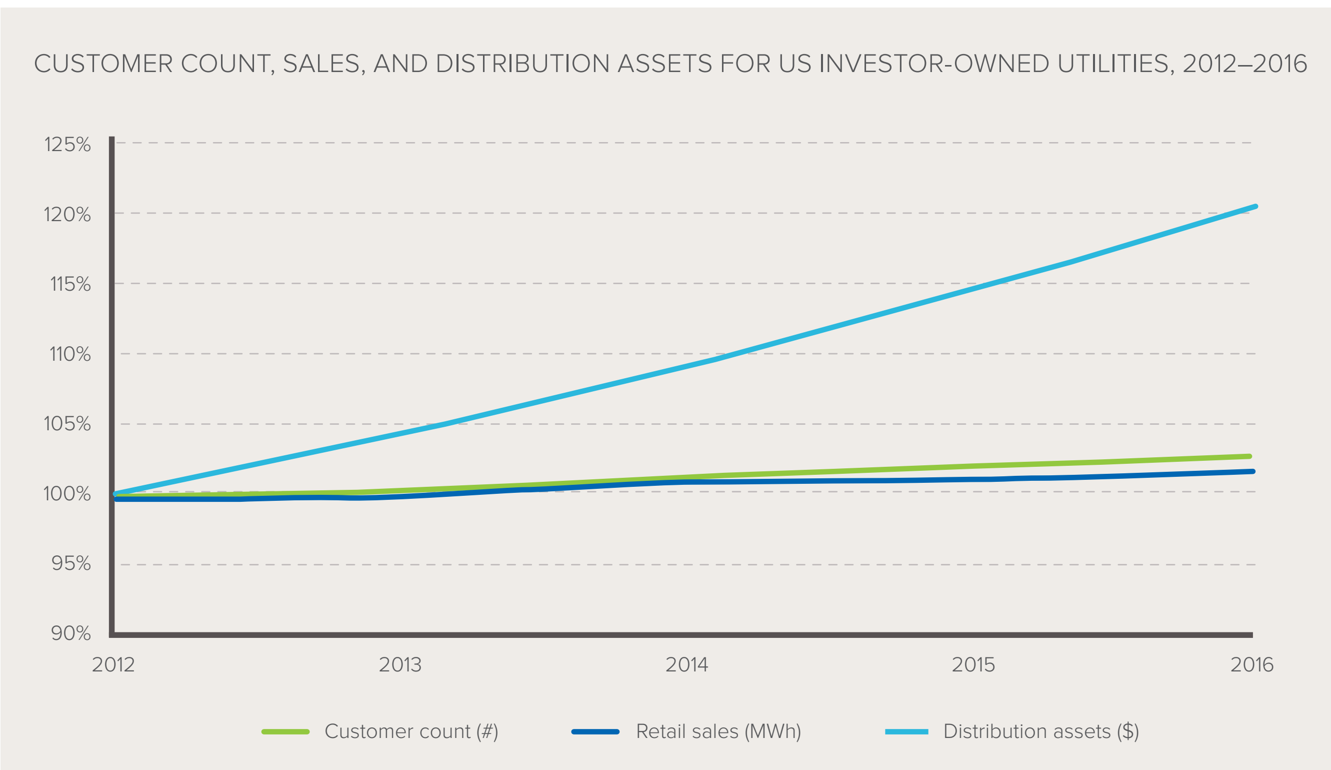


Source: RMI analysis of Bloomberg data

hundreds of millions of electricity end-users. Utilities have an incentive to make these investments because they are entitled to earn a regulator-approved rate of return on capital expenses (e.g., power plants, distribution lines, transformers) that are included in their rate base. In recent years, even as electricity sales and peak demand have stayed flat, utility investments included in the rate base have increased. The rising ratio of utility distribution assets per customer raises concern that rates may increase as the cost of distribution investments are passed through to customers for years to come.[7] To mitigate this risk, it is critical that grid investment decisions are prudent and result in the most cost-effective solutions.

FIGURE 2

INVESTOR-OWNED UTILITY DISTRIBUTION ASSETS PER CUSTOMER ARE INCREASING DESPITE STAGNATING ELECTRICITY CONSUMPTION (DATA NORMALIZED SO 2012=100)



Source: RMI analysis of S&P global data

Distributed energy resources can be used in non-wires solutions to save ratepayers money

Utilities and regulators can adapt planning processes to changing market dynamics and consider all possible solutions when making investments to address grid needs. Specifically, by taking advantage of the proliferation of distributed energy resources (DERs) and energy management software solutions, planning can ensure grid services are provided by the most cost-effective options, while ensuring safe, reliable electric service for customers.

For the purposes of this report, we define DERs to include the range of demand- and supply-side software and hardware resources that generate electricity or control loads and can be deployed throughout low-voltage electric distribution systems to meet energy and reliability needs. Common demand-side DERs include energy efficiency measures that reduce loads, and demand response mechanisms to regulate loads by generating electricity or otherwise reducing demand. Typical supply-side DERs are distributed generation technologies like rooftop or community-scale solar PV and combined heat and power systems. Energy storage resources like batteries are DERs that can act as both demand- and supply-side resources by serving as either load or generation as needed. Any of these DERs can be installed on the customer or utility side of the meter, and can be owned by the user, a third party, or the utility.

EXAMPLES OF DERs

- Responsive Building Equipment Controls (e.g., lighting sensors/controls, thermostats, water heater controls)
- Behavioral Demand Response (i.e., human responses to signals sent through various media)
- Energy Storage (e.g., battery, thermal, and others)
- Building Equipment Upgrades (e.g., lighting, HVAC equipment, or appliance replacements)
- Distributed Generation (various renewable and non-renewable resources)

When DERs are used to solve grid needs that would have otherwise required traditional utility infrastructure, they can be considered non-wires solutions (NWS). NWS are applications of DERs in specific locations that defer or eliminate an investment in traditional and costlier "wires-and-poles" infrastructure solutions. NWS have also been called non-wires alternatives (NWAs), which implies that they will be evaluated as alternatives to wires-and-poles infrastructure. In contrast, the terminology of "non-wires solutions" institutionalizes them as part of the utility's standard solution toolkit, implying that they should be considered as part of the default set of options.

Non-wires solutions provide a host of benefits and should be a key component of innovative distribution planning processes

In its 2018 state of the market reports for demand response and energy storage, the Smart Electric Power Alliance found that over half of the ~150 utilities surveyed were interested in NWS.[8] Catering to such growing interest, this playbook for non-wires solution implementation focuses on the application of NWS at the distribution-level, which is the largest utility capital investment category. Many of the recommendations presented here can be adapted for transmission-level projects, but distribution-level opportunities can be directly addressed by state actors such as public utilities commissions, and can avoid more complicated inter-state transmission investment issues associated with federal regulation.

Practically speaking, states and utilities can incorporate NWS into distribution-level grid modernization and integrated planning efforts that are increasingly taking place across the nation. A working group drawn from three national labs highlighted 16 state-driven efforts that are underway in response to the combination of increased penetration of DERs and aging grid infrastructure.[9] The North Carolina Clean Energy Technology Center also recently catalogued over 300 actions related to grid modernization pursued across 42 states and the District of Columbia solely during Q2 2018.[10] Using a range of approaches, these efforts provide a set of precedents that can be built upon to capture the many benefits that DERs and NWS provide, including:

- **Ratepayer cost savings:** Since NWS are typically pursued only if they are determined to be more cost-effective than alternative infrastructure options, they should therefore lead to lower costs for ratepayers.
- **Flexibility for planning processes:** Instead of investing in new infrastructure projects based on long-term, uncertain forecasts, planners can deploy modular, flexible non-wires solution portfolios when and where they are needed. This mitigates the risk that large investments will become stranded if load growth doesn't materialize as forecasted and provides a time-value-of-money benefit since more significant expenditures can be delayed until needs are realized.
- **Progress toward clean energy goals:** NWS projects deliver value by deferring or eliminating the need for traditional infrastructure. By stimulating demand and increasing the adoption of low-carbon resources like energy efficiency and demand response, NWS reduce the need for marginal, more carbon-intensive generation (see The Scale of the Non-Wires Solution Opportunity in a Changing Grid on page 16).
- **Opportunities to test new utility business models:** Utilities can use NWS to experiment with new ways of engaging with their customers and innovative technology companies. As utilities adapt to a changing set of consumer preferences, NWS can provide an opening to partner with customers and create DER programs that improve customer satisfaction and reduce the probability of ratepayer defection.
- **Local economic development:** Rather than deploying traditional utility-owned infrastructure, NWS can provide opportunities for local investment in communities where customer-sited solutions can address grid needs.
- **Job creation:** Whereas traditional infrastructure equipment markets are mature, non-wires solution projects support the animation of DER markets

in which rapid innovation is unlocking significant potential for new job growth.

To scale NWS several important market barriers must be addressed

Despite these significant benefits, markets for NWS remain nascent. Although utilities across the nation spend tens of billions of dollars each year on distribution infrastructure, only a few have pursued NWS at scale. This slow uptake is due to a number of barriers, including:

Regulatory frameworks that do not always encourage NWS

- Traditional cost-of-service utility regulation incentivizes capital investment in grid infrastructure, thus discouraging cost-saving NWS.
- Distribution planning processes have historically been opaque, making it difficult for regulators and market participants to identify and develop alternative solutions to address utility grid needs.

Limited utility processes and expertise around NWS

- At most utilities, institutional capabilities are not yet sufficient to effectively and systematically plan for, procure, and manage NWS.
- Utilities do not currently have enough readily available data to verify performance of demonstrated DER capabilities in non-wires solution applications.

Limited procurement experience, which inhibits competitive non-wires solution proposals

- Without clear standards, it is challenging for utilities and developers to efficiently work together through non-wires solution procurement processes.
- Additional clarity is needed on the nature of grid needs and the criteria utilities use to evaluate bids in order for developers to produce more competitive offers.
- Cost and deployment timelines may still limit non-wires solution competitiveness in certain contexts.

This Implementation Playbook can help regulators and utilities overcome barriers to NWS and scale the market

This Playbook seeks to address barriers to NWS and catalyze non-wires solution deployment across the nation. It draws upon interviews conducted with more than 65 experts across 15 states, including over 20 utilities, as well as developers, regulators, and trade associations.

Our intent is to provide a common set of recommendations that any jurisdiction can build upon to directly implement and scale NWS. The Playbook is composed of two sections:

Section 1: Best Practices

An in-depth discussion of best practices for the three enabling factors that are critical for non-wires solution implementation:

1. Establish a supportive **regulatory** environment
2. Integrate NWS into standard **utility** operating procedures
3. Employ a holistic process for non-wires solution **procurement**

Section 2: Implementation Guidelines

Practical implementation guidelines for the four key components underpinning non-wires solution implementation:

1. **Screening criteria** to identify potential non-wires solution projects
2. **Competitive solicitation** processes that lead to meaningful responses
3. **Evaluation frameworks** to determine if non-wires solution projects are viable and competitive
4. **Contract terms** attuned to non-wires solution project characteristics

As with all effective practices, non-wires solution processes are likely to evolve as lessons are learned from non-wires solution procurement and implementation. Despite the US market only representing ~2 GW of non-wires solution capacity at different stages of development as of April 2017, there is significant opportunity for rapid acceleration of non-wires solution deployment as utilities and regulators adopt and standardize best practices.[11]

THE SCALE OF THE NON-WIRES SOLUTION OPPORTUNITY IN A CHANGING GRID

Non-wires solutions can both increase the value of DERs deployed on the grid and increase the achievable market size for DERs by expanding revenue streams available to these resources. By expanding the cost-effective market size for DERs, NWS can lead to significant direct and indirect carbon emissions savings. At a national scale, we conservatively estimate that NWS could increase the achievable market size for DERs by approximately 6%, and lead to CO_2 reductions of nearly 300 million tons over the next 20 years.

Non-wires solutions can improve the system benefits of DER deployments and help realize over $17 billion in additional net present value from DERs through 2030 across the US

Directly capturing the distribution-level benefits (e.g., distribution capacity deferral value[12]) of DERs at the project level via a non-wires solution can dramatically increase the system value of DERs. In light of the disparity in avoidable costs across distribution systems noted by other analysts,[13] and the corresponding difficulty in assigning a single value to distribution benefits, we instead highlight a few examples where NWS or similar programs that capture value from avoided costs on the distribution system can significantly improve the benefits available from DER deployment.

- **Energy efficiency:** In a regulatory filing from National Grid in Massachusetts,[14] the utility lays out the total resource cost-benefit ratio for a wide range of energy efficiency programs. Including the utility's estimated distribution-level benefits in the cost-effectiveness calculation improves the average cost-benefit ratio by a savings-weighted average of 31%, compared to excluding distribution-level benefits from the cost-effectiveness calculations.
- **Demand flexibility:** RMI's 2018 study on demand flexibility technologies assessed the cost-effectiveness of eight different control strategies for reducing peak demand and lowering energy costs at the bulk system level.[15] We estimated the size of a least-cost portfolio of these strategies where the investment in the demand flexibility technologies was at cost parity with new gas-fired power plants to balance renewables, without accounting for distribution benefits. When we included distribution system benefits in the calculation, we found that the size of the demand flexibility portfolio was 32% greater than the scenario in which distribution benefits were excluded.
- **Batteries:** RMI's 2015 study examining the economics of battery storage across four different use cases examined the value of a fleet of batteries providing peak reduction services in the Brooklyn–Queens Demand Management non-wires solution project in New York.[16] In that case, including the distribution system benefits associated with battery deployment (i.e., the avoided costs of the substation upgrade in question) increased project revenue and system

value by over 100%, more than doubling the total value that would otherwise be delivered by the batteries providing wholesale market- and customer-facing services.

Even if DERs are cost-effectively deployed without directly addressing distribution-level avoided costs, the total system benefit provided by DERs can increase significantly when we consider those distribution benefits. For example, a recent RMI study examined the potential for a portfolio of DERs and utility-scale renewables to cost-effectively replace retiring fossil generation and avoid new investment in gas-fired generation.[17] The report examined a business-as-usual scenario in which new gas capacity replaces retiring capacity, as well as a clean energy scenario in which DERs and renewables replace most retiring capacity. Without valuing any distribution-level benefits of DERs, the scenarios are approximately equal in total present value costs; however, when valuing the avoided distribution-level costs at an average value of peak reduction,[18] the additional avoided costs associated with that level of DER deployment is approximately $17 billion through 2030. In other words, by capturing the distribution-level peak reduction and other benefits associated with an already cost-effective deployment level of DERs, non-wires solution projects that target DER deployment in areas of grid need can provide an additional $17 billion in value to the grid through 2030 by avoiding investment and upkeep of traditional distribution assets.

Non-wires solutions can unlock higher levels of DER deployment, offering significant carbon emissions reductions

Increasing DER deployment can provide carbon emissions reductions via both direct and indirect mechanisms.[19] DERs can help realize direct carbon reductions by avoiding carbon-intensive electricity generation on the bulk power system, either through line loss reduction, energy savings from efficiency measures, load shifting, or distributed generation from low-carbon sources. RMI's 2018 study examining the market size for clean energy portfolios found that a 1% increase in assumed DER adoption from the base case would directly reduce emissions through 2030 by 37 MT CO_2[20]—approximately equivalent to the total lifetime emissions from a new-build 1,000 MW combined-cycle gas turbine.

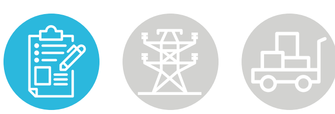
DERs can also enable indirect carbon savings by providing flexibility, thus reducing curtailment from and incentivizing investment in low-cost, zero-carbon, but variable energy resources like wind and solar. RMI's study on the potential impacts of demand flexibility found that shifting load can increase wind and solar energy project revenue by nearly 40%, incentivizing further investment in these resources in the long run.[21] Scaling the results of that Texas-focused study to represent national electricity consumption patterns, we found that for every 1% increase in demand flexibility deployment compared to the base case, 20-year CO_2 emissions fell by 11 MT CO_2, equivalent to 30% of the direct impacts.

While it is clear that the potential to reduce CO_2 through DER deployment is large, it is difficult to forecast the total magnitude by which NWS can increase deployment of DERs. As a conservative forecast, we evaluated the extent to which valuing the distribution-scale benefits of DERs would increase the cost-effective magnitude of deployment for both energy efficiency (using National Grid's 2016 filing noted above) and demand flexibility (using the supply curves presented in RMI's 2018 study). We find that increased cost-effective DER deployment and demand flexibility, enabled by valuing distribution benefits via NWS, would lead to approximately 6% greater CO_2 savings compared to the case in which distribution benefits are not valued in cost-benefit analysis. Combining that finding with the sensitivity analysis described above suggests that enabling distribution system revenue via NWS, scaled nationally, could avoid approximately 300 MT CO_2 over an assumed 20-year lifetime of DER assets.

This estimate is likely conservative, as flattening cost declines in efficiency, demand response, storage, and distributed generation will extend the supply curves for these technologies, leading to greater impact from the incremental value streams provided by NWS and correspondingly higher deployment levels. Opening up further opportunities for NWS, and thus DER deployment, by making them a common planning option can compound the impact, allowing for additional avoided costs and further scaling of carbon savings from DERs.

BEST PRACTICE FRAMEWORK

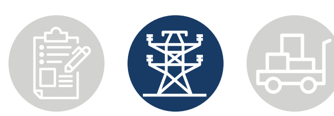
We have identified three key elements that are critical for creating and sustaining successful NWS programs: establishing a supportive regulatory environment, integrating NWS into standard utility operating procedures, and creating a holistic process for non-wires solution procurement. Each element is underpinned by a series of best practice recommendations listed below, which, in the aggregate, create the necessary conditions to support the full life cycle of non-wires solution deployment.



1. **Establish a supportive regulatory environment.** The regulatory environment, including rulings, precedents, and ongoing processes, is instrumental for enabling a scalable market for NWS in a particular jurisdiction. The regulatory framework at its best can elicit flexible responses from utilities and solution providers to ensure reliability and meet cost-reduction goals, without being overly prescriptive.

   Experience from non-wires solution projects across the US suggests that a supportive regulatory environment for NWS can:

   a. **Leverage the legislature** to drive systematic consideration of NWS
   b. **Provide an appropriate incentive structure** to encourage utilities to pursue non-wires solution projects
   c. **Clarify screening and evaluation criteria** to efficiently identify and assess non-wires solution opportunities
   d. **Enable data transparency** and access for solution providers
   e. **Encourage DER forecasting** to identify potential low-cost NWS that could take advantage of organically adopted DERs
   f. **Support collaborative stakeholder processes** to allow for input into non-wires solution processes from all interested and affected stakeholders



2. **Integrate NWS into standard utility operating procedures.** Processes and organizational structures within utilities can either facilitate or act as barriers to non-wires solution-oriented planning and procurement. Advanced utility processes can allow for the fair comparison of NWS against traditional solutions and encourage the effective engagement of external market

participants to best meet regulatory and utility-level objectives.

Utility experience in non-wires solution projects suggests that a well-designed set of organizational processes within a utility can:

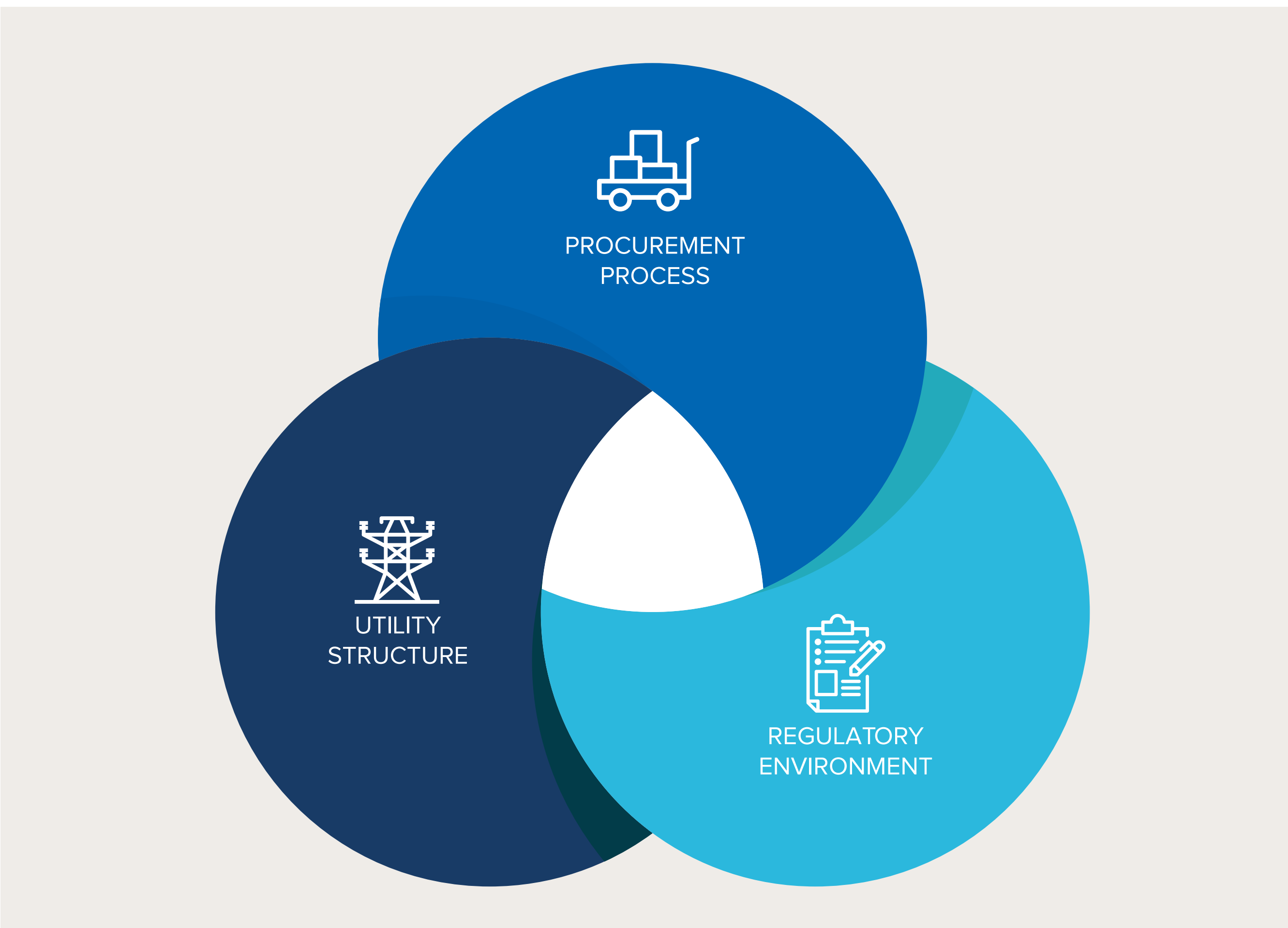
a. **Consolidate accountability for non-wires and traditional solutions** within a single interdisciplinary utility team to facilitate fair assessment between different approaches

b. **Allow for both utility- and provider-led integration** of diverse technologies to meet grid needs

c. **Scale successful non-wires solution pilots to full deployment** in order to maximize learning and provide the greatest economic benefit

3. **Employ a holistic process for non-wires solution procurement.** Well-designed procurement practices can help ensure that opportunities to offer solutions are made available to the market in an efficient and fair manner that enables effective proposal development.

FIGURE 3
BEST PRACTICE FRAMEWORK



Utility and solution provider experience suggests that procurements should consider the range of options for sourcing NWS, including pricing and expansion of customer programs in addition to dedicated procurement via competitive solicitation. Since competitive solicitations have long been a predominant sourcing mechanism used for non-wires solution projects, this Playbook focuses on two key sets of recommendations to improve solicitation practices:

1. **Process enhancements** for the methods and interactions by which non-wires solution solicitations are developed:
    a. **Engage developers and other stakeholders** throughout the procurement process
    b. **Consider the role of third parties** in procurement

2. **Best-fit technical approaches** for developing the content of a request for proposal (RFP) to maximize the probability for technically feasible and cost-competitive results:
    a. **Provide data-rich needs descriptions** for the solutions being requested
    b. **Elaborate performance attributes for solutions** rather than technology requirements
    c. **Provide clear proposal evaluation criteria** as part of the solicitation
    d. **Keep options open for further DER market evolution,** including wholesale market participation and/or distribution-level service pricing
    e. **Lay out clear requirements in project contracts** to fairly allocate risk and ensure operational reliability

To address all of the recommended best practices for non-wires solution implementation, involvement is needed from four key stakeholders: legislators, regulators, utilities, and developers. As illustrated in Figure 5 on pages 22–23, these four entities have distinct—and overlapping—roles and responsibilities to establish, cultivate, and guide the non-wires solution market. Whereas the legislature's role is primarily in the earlier stages of this market's development, the other three stakeholder groups are expected to collaborate throughout the entire non-wires solution life cycle.

This Playbook's recommended best practices can be implemented in any utility context

The first section of this Playbook provides a detailed discussion of recommendations that each stakeholder group can adopt to implement the three core elements of the best practices framework for non-wires solution programs: a supportive regulatory environment, NWS integrated into utility operations, and holistic solicitation processes. Since every jurisdiction will need to adapt these recommendations to most appropriately suit their local circumstances, following the discussion of each of the three best practice elements is a table that describes key considerations for implementing the framework recommendations across three archetypical market structures:

- Vertically integrated investor-owned utilities (VIUs): VIUs own transmission, distribution, generation, and billing, and traditionally earn a regulated rate of return on prudently invested capital.
- Investor-owned utilities in restructured states (wires-only utilities): Wires-only utilities own distribution assets (not generation) and also earn a regulated rate of return based on their cost of service.
- Consumer-owned and nonprofit utilities: Consumer-owned and other nonprofit utilities are typically not regulated by state agencies but are overseen by member boards or city councils. Cooperative and municipally owned utilities (co-ops and munis) are among the most common of this type and are run by and for members of a community, or by a municipality. Federal power marketing agencies

like Bonneville Power Administration and Joint Power Authorities composed of a collection of municipalities also fall in this category as they are nonprofit and not regulated by state public utilities commissions. For the purposes of this report, we focus on the specific characteristics of co-ops and munis while recognizing the applicability of NWS to a broader set of nonprofit utility types.

FIGURE 4

THREE ARCHETYPAL UTILITY MARKET STRUCTURES

VERTICALLY INTEGRATED UTILITY	WIRES-ONLY UTILITY	CONSUMER-OWNED AND NONPROFIT UTILITIES
Vertically integrated utilities (VIUs) have a monopoly over electricity generation, transmission, distribution, and billing. In some vertically integrated states, customers may be able to choose their retail provider. Regulatory agencies oversee all VIU investments and costs. The VIU's capital and non-capital investment decisions are driven by what regulators allow them to include in their rate base and the permitted rate of return on those investments.	In states with restructured electricity markets, generation, transmission, and distribution are unbundled, and customers may be free to purchase from any suppliers on the grid. Utilities purchase electricity from generation companies via market mechanisms (such as power exchanges), which are typically conducted by independent system operators. Wires-only utilities do own distribution infrastructure, from which they earn regulated returns. Like VIUs, these investment decisions are overseen by regulators.	Unlike VIUs and wires-only utilities, consumer-owned and nonprofit utilities do not seek to earn a return for shareholders. Still they must have sufficient capital to support operations, maintain infrastructure, and invest in new initiatives. Co-ops operate on a not-for-profit basis and are owned by their members. Generation and transmission (G&T) co-ops provide electricity to distribution co-ops through their own generation or by purchasing power on behalf of distribution members. Many distribution co-ops face restrictions that limit how much generation they can own. Decisions are overseen by boards composed of members. Municipal utilities also operate on a not-for-profit basis and are owned and operated as city-operated agencies. Revenues are collected by the municipality, and can be subject to city council budgets and trade-offs with other city costs. Decisions are overseen by the city government.

FIGURE 5

NWS ROLES AND RESPONSIBILITIES

Group is engaged

	ROLES & RESPONSIBILITIES	LEGISLATURE	REGULATORS	UTILITY	DEVELOPERS
PHASE 1 Creating a hospitable environment for non-wires solutions	**Define a vision.** Who determines the vision for pursuit of non-wires solutions in a given jurisdiction?	**Articulates** a vision by introducing bill that supports new procurement practices	**Initiate** a proceeding to support vision development and implementation of non-wires solutions	**Expresses** goals for implementation and how the non-wires solutions support their business	**Ongoing** role in stakeholder engagement processes
	Develop incentives. Who is responsible for creating and defining the incentives?	**Provides** impetus for non-wires solutions incentives through legislation	**Develop** the appropriate incentive structure for non-wires solutions	**Engages** in developing the incentive framework for non-wires solutions or proposes incentives to regulators	
	Consider projects systematically. Who ensures that non-wires solutions are consistently considered as part of the utility planning process?	**Mandates** that utilities consider non-wires solutions that meet prescribed criteria	**Define** the process for how non-wires solutions projects are considered	**Establishes** internal processes for consideration of non-wires solutions	
PHASE 2 Identifying non-wires solutions opportunities	**Identify screening criteria.** Who designs the screening criteria for non-wires solutions?		**Define** the process for determining the criteria for identification of non-wires solutions	**Refines** screening criteria for particular circumstances	
	Share data. Who decides what utility data is made available?		**Define** requirements and process for sharing data to support development of non-wires solutions	**Ensures** data is collected and shared to enable non-wires solutions while maintaining customer and data security	

Table is continued on the next page

FIGURE 5 (CONTINUED)

Group is engaged

	ROLES & RESPONSIBILITIES	LEGISLATURE	REGULATORS	UTILITY	DEVELOPERS
PHASE 3 Developing and executing the procurement	**Scope the procurement.** Who determines needs and opportunities for non-wires solutions?		**Facilitate** project development, including approvals, cost recovery decisions, and process oversight (ongoing)	**Determines** needs and opportunities with data-based problem descriptions	**Propose** new and refine existing needs based on utility and other data
	Identify applicable technologies. Who determines what technologies are appropriate solutions to meet identified needs?			**Defines** solutions to be technology-agnostic and performance-based	**Propose** technologies and portfolios of solutions that can most effectively address needs
	Integrate technology portfolio. Who determines the appropriate technological solutions to meet the need identified?			**Integrates** portfolio of solutions to meet need	**Integrate** portfolio of solutions to meet need through contract with utility
	Determine asset ownership. Who owns the project? Are there any regulatory restrictions or requirements?			**Owns** some or all of the components in a non-wires solutions portfolio	**Own** some or all of the components in a non-wires solutions portfolio
PHASE 4 Implementing non-wires solutions	**Oversee operations and dispatch.** Who directs the operations of the project?			**Directs** project operations to meet needs and controls owned assets	**Control** assets under contract per utility terms, instructions, and signals
	Manage performance. Who assumes project performance risk?			**Assumes** risk for ultimate grid reliability and performance risk outlined in third-party contracts	**Accept** contracted performance risk associated with assets owned and contracted to utility
	Administer measurement and verification. Who is responsible for ongoing measurement and verification?			**Requires** and conducts specific measurement and verification practices to collect operational data	**Perform** ongoing measurement and verification to demonstrate performance per contract terms

01 SECTION 1: BEST PRACTICES

BEST PRACTICES

1. ESTABLISHING A SUPPORTIVE REGULATORY ENVIRONMENT

With few exceptions, almost all non-wires solution projects and programs developed to date have been driven by regulatory action. Regulators can play several key roles in reducing barriers and accelerating non-wires solution deployment. To start, regulators can establish a vision for NWS within their jurisdiction and send clear signals to developers and utilities that NWS can be desirable, cost-effective alternatives to traditional infrastructure. In line with that vision, regulators can develop mandates or incentives that encourage utilities to systematically consider non-wires solution deployment. Regulators can also direct utilities to integrate consideration of NWS into existing planning processes or create a new independent entity to source non-wires solution opportunities. Once non-wires solution projects are identified, regulators can further encourage market growth by supporting transparent evaluation and approval processes for NWS.

a) Leverage the legislature to drive systematic consideration of NWS

In states where regulators may have limited statutory authority, state legislatures can take on a larger role in reducing market barriers for NWS. In fact, legislative bodies are often instrumental in articulating a state's vision for NWS. Legislatures can direct regulators or utilities to pursue NWS for reasons aligned with regulatory mandates (typically for just and reasonable rates, universal service, reliability, and safety), or in the interest of clean energy and other state environmental policy goals. Examples of legislatures that have initiated state action on NWS include:

- In 2006, the Rhode Island legislature passed the Energy Conservation, Efficiency, and Affordability Act, which mandated least-cost procurement and required non-wires solution consideration for system reliability investments in the distribution network.[22]
- In 2010, Maine passed its Smart Grid Policy Act that required DERs to be assessed to meet the goals of creating a more modern grid and reducing greenhouse gases.[23]
- Illinois's Future Energy Jobs Act from 2016 encourages deployment of cost-effective DERs to diversify the state's energy resource mix and protect its environment.[24]

b) Provide an appropriate incentive structure to encourage utilities to pursue non-wires solution projects

Markets with traditional cost-of-service regulation are not designed to motivate utilities to pursue NWS. Because they receive a rate of return on capital investments, utilities are incentivized to maximize spending on infrastructure, including distribution system upgrades, and not pursue lower-cost solutions. This tension between the regulated incentive structure for utilities and ratepayer costs has resulted in highly contested proceedings for utility investment proposals. Increasingly, utilities are being asked to justify large distribution spending plans, as stakeholders attempt to ensure investments are necessary for grid reliability or relate to structural grid modernization rather than one-off projects or those perceived to bolster utility returns.[25] To better align utility and ratepayer interests, it is critical for regulators to motivate utilities to pursue NWS by providing them with mandates and/or incentives.

Mandates or Incentives?

Although not mutually exclusive, there are two main channels regulators can pursue to support NWS: mandates and incentives.

Non-wires solution mandates have catalyzed the market

Mandates that require utilities to consider NWS for needs that meet certain criteria have been broadly applied. A number of states—including California, Maine, New Hampshire, New York, Rhode Island, and Vermont—require utilities to consider distribution-level non-wires solution projects that meet defined screening criteria. Most recently, the Michigan Public

Service Commission proposed a new Distribution Planning Framework, which also includes a requirement to develop non-wires solution screening criteria and identify potential non-wires solution projects.[26] In addition to mandates that trigger an evaluation of potential non-wires solutions, California and New York have required utilities to develop non-wires solution pilot projects (see **Non-Wires Solutions Pilot Projects** on page 29).

Mandates like these have been an effective tool to catalyze non-wires solution markets, but care should be taken to ensure market flexibility and manage compliance. To avoid inhibiting non-wires solution market growth, mandates should be structured to encourage flexible compliance options. For example, instead of requiring NWS projects to include specific technologies, a mandate could instead require technology-agnostic solicitations. This flexibility can support the mandate's desired regulatory outcomes while fostering innovation from market participants.

Regulators must also have effective strategies to monitor compliance with mandates. For example, to verify that utilities apply required screening criteria accurately, regulators need to perform due diligence on utility analyses. This might require a substantial time commitment and a need for regulators to acquire additional resources, learn new skills, and build internal capacity. Moreover, if a state does not have a transparent distribution planning process, the necessary data may not even be available for regulators to evaluate compliance. For these reasons, mandates need to be carefully designed and sufficiently supported by regulatory expertise to instill confidence in market participants, maintain reasonable timelines for project approvals, and sustain market growth.

> **"One might ask: why provide the IOUs with any incentive at all? Why not just direct the utilities to choose DERs whenever they are less costly than traditional distribution investments? The problem is that, given the complexity of the distribution system, this Commission is ill-equipped, at least at present, to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist… Practically speaking, command-and-control regulation faces major challenges in this context. Instead, if our objectives are to be achieved, we should create the appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own shareholders' interests."**
>
> **— Former California PUC Commissioner Mike Florio on mandates versus incentives[27]**

Incentives that align utility compensation with cost-effective deployment of NWS promote long-term market growth

As detailed by Wood Mackenzie Power & Renewables in its 2017 state of the non-wires solution market report, a range of incentive structures for NWS has been tested.[28] The first category of incentives allows utilities to earn a rate of return on NWS projects, similar to the rate of return earned on the traditional utility rate base. With incentives based on rate of return, utilities will still try to maximize spending on distribution system upgrades, but upgrades may now include non-wires solution portfolios. This type of incentive enables NWS to compete with traditional projects of similar cost but does not necessarily motivate utilities to pursue more cost-effective solutions. Regulators in California and New York have tested this incentive and experimented with variations on a rate of return for total expenditures on NWS: in New York, some NWS have earned even higher rates of return than traditional investments if they achieve specified performance goals, and in California, utilities have earned a fixed rate of return on payments to non-wires solution developers.

The New York State Department of Public Service has also piloted a new type of incentive that attempts to overcome the utility's bias to maximize capital expenditures. The share-of-savings incentive, used in the Central Hudson Peak Perks project,[29] allows utilities to earn a percentage of the savings achieved by a non-wires solution project. The Peak Perks project uses demand response pricing and rebates to encourage customer load reduction and adoption of Wi-Fi-enabled thermostats and pool pumps. Central Hudson is authorized to earn back 30% of the savings from the Peak Perks project, while 70% of the savings must be passed onto ratepayers. The risk inherent in share-of-savings incentives is that utilities will only pursue NWS that provide substantial savings, and will not consider projects where DERs could provide a lower-carbon solution at, or near, cost parity. Moreover, determining the utility's portion of the savings can be a contentious and lengthy process. For this reason, more standardized and agreed-upon rates would help the share-of-savings incentive structure scale. Overall, expanding the implementation of share-of-savings incentives represents one of the most promising options to motivate utilities to identify NWS that deliver the greatest ratepayer benefits.

Trends in performance-based regulation and platform utility models may provide utilities with new revenue streams and provide regulators the opportunity to test new approaches

Broader trends in performance-based regulation could provide additional motivation for utilities to pursue NWS. Several states are considering incentives that equalize earning opportunities for utility procurement of service-based solutions (e.g., solutions typically procured through ongoing service contracts such as load management through software, or energy efficiency programs) with earning opportunities for procurement of infrastructure. Methods being tested include allowing utilities to earn a fixed rate of return on qualified service expenses or to prepay service contracts that are added to the rate base as lump-sum expenses.[30]

As described in RMI's ***Reimagining the Utility*** report, some states are considering policy changes that enable utilities to serve as integrators and hosts for market activity, earning revenue for providing these platform services. In New York, the concept of distributed system platforms operated by the utility provides a roadmap for how the platform concept could be leveraged to enable NWS. The transition toward compensation for services and platform revenues could fundamentally change the utility business model and animate the non-wires solution market as utilities increasingly engage third-party providers to meet needs at all levels of the grid. This platform-oriented approach will also require regulators to provide nimble oversight for a fast-paced, transactional market. Non-wires solution projects can be an opportunity to begin building these streamlined processes and testing new approaches for regulation.

Utilities and other stakeholders can influence non-wires solution deployment in the absence of regulation

Non-wires solution programs have not always been initiated by a regulator or legislature—they have also been initiated by utilities themselves and influenced by stakeholder intervention. Arizona Public Service (APS) decided to deploy storage to defer replacing 20 miles of transmission and distribution lines to the rural town of Punkin Center. In deploying 2 MW and 8 MWh of battery storage at Punkin Center, APS stated that the project was very cost-effective, especially when it factored in additional revenue from providing frequency regulation, participating in capacity reserve markets, and arbitraging wholesale power markets. The project also helped APS to meet storage installation goals that had been set through a memorandum of understanding (MOU) with Arizona's Residential Utility Consumer Office (RUCO). The MOU was initiated through a settlement for an APS filing that proposed adding gas generation to its Ocotillo Power Plant, and also stated that APS would consider all alternative resources for future projects. This MOU was only one of many factors in APS's decision to install storage at Punkin Center but demonstrates a potential pathway for stakeholders to influence utilities to consider NWS.

Flexible or prescriptive?

Regulators have taken a variety of tactical approaches to reduce market barriers to widespread non-wires solution adoption. In New York, regulators created a flexible framework through its Distributed System Implementation Plan guidance, which left room for utilities to experiment their way forward.[31] Through stakeholder processes, the Department of Public Service approved initial adders to compensate NWS, but allowed each utility to design and propose its own adders or other incentives. The Department of Public Service similarly developed a benefit-cost analysis (BCA) whitepaper to guide evaluation of investments (including NWS) but allowed utilities to finalize their own BCA handbooks and streamlined the regulatory approval process for projects that pass BCA tests. Utilities have reacted to this regulatory flexibility by testing different strategies to identify the scalable approaches that work best for their specific context. Another benefit of New York's flexible approach is that stakeholders are able to collectively learn from a range of implementation approaches instead of all being committed to a single path. However, providing such latitude does carry the risk that non-wires solution development will be haphazard and disjointed in the absence of a clear and uniform path to scalable implementation.

In contrast to New York's experience, regulators in California took a more structured approach to non-wires solution implementation. Through its Distributed Resource Plan proceeding, utilities were required to pursue a specific set of non-wires solution demonstration projects to test the application of NWS for different grid needs.[32] Utilities were also required to develop a formal distribution investment deferral process to systematically identify and propose NWS as part of their annual planning. A separate set of requirements from California's Integrated Distributed Energy Resources proceeding mandated that utilities solicit competitive bids according to a detailed solicitation framework that was associated with a defined incentive structure and value.[33] California pursued this prescriptive approach to establish comprehensive and consistent statewide non-wires solution processes in which results from pilots would inform standard distribution planning practices to identify and procure capex deferral opportunities. The mandates ensured specific non-wires solution hypotheses could be tested, but also required extensive regulatory involvement. Drawbacks of this approach are both temporal (slowing down market development given the requirement to conduct a series of pilots before moving to operationalize the results) and substantive (utilities could not devise projects that focused on issues outside of CPUC's list).

As an indication of the comparative success New York and California have had deploying NWS, it is interesting to note that although both states began developing non-wires solution strategies in 2014, as of April 2017 New York had ~1 GW of projects in its pipeline, while California only had ~100 MW.[34] Evidently, the more flexible New York approach spurred faster non-wires solution adoption. As an indication that California may be ramping up its deployment of NWS, utilities there recently released their first Distribution Deferral Opportunity Reports reflecting hundreds of MW of identified potential non-wires solution opportunities.[35] These reports will be updated annually and represent a major shift in California transitioning out of its

NON-WIRES SOLUTIONS PILOT PROJECTS

Flexible versus prescriptive approaches to non-wires solution demonstration projects in California and New York provide two instructive examples on how demonstration project design can impact adoption of NWS. In both states, regulators provided utilities with guidelines to pilot NWS, but their approaches and outcomes were quite different.

In 2014, the California Public Utilities Commission (CPUC) required the state's three investor-owned utilities to develop distribution resources plans that included the design of five demonstration projects, each of which tested a particular technical issue associated with the value and location of DERs on the grid.[36] Two of these demonstration categories were particularly relevant for gaining experience with NWS as they required project proposals for deferral opportunities based on locational benefits, and the provision of multiple grid services. In 2016, the CPUC required another set of demonstration projects through the Competitive Solicitation Framework and Regulatory Incentive Pilot, which prescribed four grid services that NWS could provide, established a procurement process and fixed incentive, and required utilities to develop between one and four NWS projects to test the pilot structure.[37]

By contrast, the New York State Department of Public Service provided less prescriptive guidance to inform the development of non-wires solution pilots. Utilities were first required in 2015 to propose at least one non-wires solution pilot in their initial distributed system implementation plans.[38] Additional regulatory direction was provided in 2016 when utilities were required to identify non-wires solution opportunities in their capital investment plans.[39] The Department of Public Service also created a list of principles that utilities were expected to incorporate into the DER demonstration projects they created. The principles were designed to encourage utilities to develop partnerships with third-party service providers, seek solutions from market participants, test different price and rate design frameworks, and propose rules to support competitive markets. These principles were more open-ended than the pilot guidelines in California as they were designed to encourage utilities to use demonstration projects as a way to test different market mechanisms for NWS.

The contrasting pilot design approaches in California and New York speak to the distinct goals of each jurisdiction. California's highly prescriptive approach was geared toward devising an effective way to integrate the large amounts of DERs that already exist on their grid. As a result, regulators in the state focused more on developing standardized technical and operational requirements to efficiently interconnect and manage projects of certain types. By contrast, New York's flexible-by-design strategy was aligned with the context of its Reforming the Energy Vision process, which is intended to redesign the utility business model and encourage entrepreneurial approaches through permission to experiment.[40]

For utilities in states without specific regulatory guidance on DER demonstration projects, there is an opportunity to learn not only from the results of non-wires solution pilots in other jurisdictions, but also from the design of such pilot programs. Utilities intending to integrate NWS into their core operations should seek to create pilots that test clearly defined operational, technical, or rate design questions required to support non-wires solution programs as part of the utility business model. In doing so, they should engage with market participants to effectively explore different approaches to designing pilots that test those questions.

pilot experimentation phase to more standardized procurement at scale. Still, the capacity of deployed NWS remains relatively low in both states given the potential.

c) Clarify screening and evaluation criteria to more efficiently identify and assess NWS opportunities

Screening criteria

A growing number of utilities and regulators are trying to redesign planning processes to better consider the ability of DERs to address grid needs. This presents an opportunity to operationalize non-wires solution screening by integrating it into the planning process. Simply put, if planned distribution upgrades meet a set of defined screening criteria such as project type, timing, and cost, an analysis is triggered to determine which option—traditional or non-wires solution—is more cost-effective. Thus far, regulators have been primarily responsible for developing screening criteria and directing their integration into utility planning. Regulators have also led or hired neutral third parties to facilitate stakeholder processes for developing screening criteria. Regulatory leadership in these processes provides stakeholders with confidence that screening criteria are being developed in a way that is transparent and neutral, and that incorporates both their needs as well as those of utilities.

Regulators should design screening criteria that utilities can customize. Utilities within a state have different grid needs, loads, generation portfolios, and customer mixes—all of which may influence the efficacy of screening thresholds within their service territory. Regulators can lead on structuring screening categories and methodologies but should allow utilities flexibility to propose changes that align screening criteria with their grids and internal processes.

Regulators should also consider the adaptability of screening criteria to changing market conditions. Screening criteria make sense in today's emergent non-wires solution market because they help point utilities toward the most suitable opportunities. As utilities become more comfortable identifying non-wires solution projects, regulators should direct that screening criteria be regularly updated and reevaluated to ensure they do not constrain potential solutions.

For more information on the development of screening criteria, see the Screening Criteria section on page 53.

Evaluation criteria

Regulators can also lead the refinement of benefit-cost analysis (BCA) frameworks to accurately value NWS. BCA frameworks for efficiency and demand-side management have long been the purview of regulators, and have been codified in documents such as the California Standard Practice Framework[41] and the New York Benefit Cost Analysis Framework.[42] BCA frameworks should be reviewed and updated to capture the full cost and value of NWS. Details on how BCA frameworks can be altered to reflect the value of NWS are provided in the Proposal Evaluation section on page 64. Regulators should also consider flexibility within BCA frameworks to allow utilities to adapt them for values and costs unique to their service territory.

d) Enable data transparency and access for solution providers

For successful development of NWS, solution providers need access to significant amounts of data, including utility system data and customer usage data. Access to data not only enables developers to propose more targeted solutions to utility needs, but also supports the regulators' oversight role by granting regulators better information to review utility planning and investment decisions.

Traditionally, the distribution system planning and investment process has occurred mostly within the utility, with little public disclosure. Regulators can play an important role in ensuring that planning processes capture system data needed to support non-wires solution development, and making data readily available to the market. They can also help define and enforce customer and cybersecurity protocols to ensure some information is redacted for security purposes without rendering the data ineffective for developers. States developing integrated distribution planning (IDP) or integrated grid planning (IGP) processes can consider including non-wires solution evaluation as a key component of those efforts and think about what types of data can be captured and made available to support development of NWS.

Specifically, non-wires solution providers benefit from public maps of grid needs and the locational value of addressing those needs. Utilities in several states, including **Rhode Island**, **New York**, and **California**, have locational value maps published or under development. In addition, public information on hosting capacity—how much additional distributed generation can be deployed on given circuits before approaching reliability issues—can be valuable to non-wires solution developers. Utilities in **Minnesota**, **Colorado**, **Hawaii**, **the District of Columbia**, **New York**, **California**, and several other states have published hosting capacity maps.

Regulators can also play a role in developing rules governing customer usage data. In 2014, the California PUC issued a rulemaking "Decision Adopting Rules To Provide Access To Energy Usage And Usage-related Data While Protecting Privacy Of Personal Data."[43] In this decision, the CPUC directed utilities to provide public, zip-code aggregated usage data to universities and nonprofits for research, and to local governments. Moreover, the decision outlines a process for other stakeholders hoping to access the data. More recently, when California investor-owned utilities restricted public access to their PV Renewable Auction Mechanism maps, the CPUC intervened and required them to restore access to the maps to ensure market transparency into hosting capacity and locational value data.[44] From the perspective of a developer of customer-interfacing NWS, clear processes for requesting data access can save time and better inform solution development. For a broader overview of national efforts on data, the American Council for an Energy-Efficient Economy provides a summary of customer data access provisions in each state.[45]

e) Encourage DER forecasting to help identify low-cost NWS that leverage expected DERs

Regulators can encourage utility planning processes to include more robust forecasting of DERs to support non-wires solution procurement. Utilities have well-established protocols for forecasting load, including sensitivity analysis. Similar forecasting can be conducted for DER growth, and can be shared with both regulators and solution providers.

DER growth forecasting could help utilities to "right-size" the scope of grid needs over time and identify more cost-effective non-wires solution opportunities. For example, if there is projected load growth that may lead to capacity issues, utilities should also understand if DER growth on the same feeder might offset some of the potential need. Moreover, utilities could use projected DER growth as part of a non-wires solution. Existing and projected resources could be leveraged through customer programs to cost-effectively reduce or eliminate the need for certain distribution system upgrades. Regulators can require utilities to demonstrate that they have considered existing and projected DERs as part of a non-wires solution or traditional project. If solution providers are given access to DER projections, they can develop proposals that leverage or synergize with those assets. Additionally, projects can be designed to be more flexible and cost-effective if developers have a clearer picture of the future demand for their products.

Regulators can define the types of sensitivity analyses that should be conducted for both load and DER growth projections. In particular, there is a need for more probabilistic planning in DER forecasting to match the degree of complexity embedded in demand forecasting. Given the inter-relationship between expected load and DER projections, a utility's ability to optimize its investments depends on a statistical analysis of the most likely future scenarios. More detailed probabilistic analyses will generate a range of expectations for how customer load is likely to change and interact with DERs in the future. This will help planners more readily consider the value flexible resources provide in addressing uncertainty and adapting to changing conditions over time.

f) Support collaborative stakeholder processes to allow for input into NWS processes from all interested and affected stakeholders

Stakeholder input is critical for the development of durable non-wires solution rules, incentives, and processes. Ideally, regulators should lead and host the stakeholder engagement process for NWS; at a minimum, regulators should be involved in all aspects of stakeholder engagement. Stakeholder engagement in developing non-wires solution processes is necessary because NWS are relatively new and more complicated than traditional approaches to capital expenditure investments, so no one individual or organization holds all the answers.

Leadership in non-wires solution stakeholder engagement by regulators—as opposed to utilities—can lend more credibility and neutrality to the process. For example, if stakeholder processes are not officially docketed for public view, there may be concerns that meaningfully different perspectives are not being adequately considered and incorporated into outcomes. Regulatory leadership of non-wires solution processes can also lead to more consistency in a state, which is valuable for scaling the market. If regulators run the stakeholder engagement process, they can set clear expectations for utilities and developers around what is required for non-wires solution project approval. In particular, consistency of processes across utilities makes it easier for solutions providers to bid their services.

Running an effective stakeholder engagement process for NWS may require capacity building of regulatory staff. Regulators can also consider engaging neutral facilitators to run the process, as a way to ensure that stakeholder feedback is collected in a collaborative, streamlined way. Given the staff capacity and stakeholder time commitment required, as well as the need to better integrate planning and non-wires solution consideration, regulators in states pursuing stakeholder engagements for grid modernization or integrated planning may consider how they can integrate NWS into those processes rather than running separate, parallel processes.

Regulators may also consider using independent researchers or technical working groups to conduct neutral analyses to support a stakeholder process. Working groups organized around specific non-wires solution topic areas have been valuable in making progress on contentious subjects in integrated planning and NWS. Working groups should be designed with tangible outcomes in mind, and with the right level of specificity to ensure that questions can be addressed during the allotted time.

As an alternative to a regulator-led process, there are models in which independent entities have run successful stakeholder engagement processes around integrated planning, DER procurement, and NWS. For example, the Northwest Power and Conservation Council manages a collaborative process to identify regional energy and conservation needs in the Pacific Northwest.[46] The Council is an independent body, and develops a resource plan every five years that utilities can reference in their own planning. In order for similar independent bodies to successfully drive change, they require firm support from regulators, utilities, and state governments.

Another approach to stakeholder engagement is currently being pursued in Hawaii where the utility Hawaiian Electric Company (HECO) is leading an innovative stakeholder engagement process as part of

FIGURE 6

MARKET-SPECIFIC CONSIDERATIONS FOR THE REGULATORY ENVIRONMENT BEST PRACTICE RECOMMENDATIONS

RECOMMENDATIONS FOR REGULATORS AND OVERSIGHT BOARDS	VERTICALLY INTEGRATED UTILITY	WIRES-ONLY UTILITY	CONSUMER-OWNED AND NONPROFIT UTILITIES
PROVIDE AN APPROPRIATE INCENTIVE STRUCTURE TO ENCOURAGE UTILITIES TO PURSUE NWS	• Performance-based ratemaking tools could be applied to reduce the incentive to build capital-intensive infrastructure. • Consider allowing a rate of return on generation resources that are used for NWS to encourage utility pursuit of NWS. • Consider a rate of return on non-capital costs (e.g., service solutions).	• Performance-based ratemaking tools could be applied to reduce the incentive to build capital-intensive infrastructure. • Definitions of which expenditures can earn a rate of return can be adjusted to consider operating expenditures for customer programs or storage and distributed generation.	• Because they are operated by and for the people of a community, the nonprofit business model seeks to provide the lowest-cost service to its customers. So long as management incentives are aligned with members' interests, co-ops and munis would be inclined to consider NWS if they are more cost-effective. • City councils or co-op boards could mandate utility consideration of NWS. • Co-ops could consider renegotiating contracts to allow for additional ownership of generation.
CLARIFY SCREENING AND EVALUATION CRITERIA TO ENABLE EFFICIENT NWS OPPORTUNITY IDENTIFICATION AND ASSESSMENT	• Regulators should be involved in convening stakeholders to develop screening and evaluation criteria that utilities can further refine. • Screening and evaluation criteria should be adapted to each utility based on the types of investments they can pursue. For example, VIUs should have evaluations that consider the impact of non-wires solution opportunities on generation, whereas wires-only companies only need to evaluate transmission and distribution impacts.		• In the absence of state regulatory oversight, screening criteria need to be developed internally. • There is potential to codevelop screening criteria among utilities (e.g., affiliated co-ops or a consortium of municipal utilities).

Table is continued on the next page

its integrated grid planning effort.[47] HECO's proposal outlines a structured engagement model with subject-specific working groups, a technical advisory panel, stakeholder council, and broad customer and public engagement. This type of robust framework for stakeholder involvement and decision-making transparency can help mitigate neutrality concerns and relieve some of the burden on regulators.

FIGURE 6 (CONTINUED)

<table>
<tr><th>RECOMMENDATIONS FOR REGULATORS AND OVERSIGHT BOARDS</th><th>VERTICALLY INTEGRATED UTILITY</th><th>WIRES-ONLY UTILITY</th><th>CONSUMER-OWNED AND NONPROFIT UTILITIES</th></tr>
<tr><td>ENCOURAGE DER FORECASTING TO ENABLE IDENTIFICATION OF POTENTIAL LOW-COST NWS</td><td>• Data to enable DER forecasting may be easier for VIUs to obtain given their oversight and control at all levels of grid infrastructure.</td><td>• DER forecasting may require more third-party coordination to collect data and predict trends given lack of ownership over generation assets, and market management by independent system operators.</td><td>• Forecasting may be more challenging for smaller utilities with fewer resources and less advanced equipment, although projections would only need to consider data for a smaller number of customers compared to a large regulated utility.

• For co-ops, there is also a need to coordinate with G&T co-ops to ensure power supply arrangements are not violated.</td></tr>
<tr><td>LEAD COLLABORATIVE STAKEHOLDER PROCESSES TO ALLOW FOR INPUT INTO NWS PROCESSES FROM ALL INTERESTED AND AFFECTED STAKEHOLDERS</td><td colspan="2">• Whether regulators lead the stakeholder process themselves, hire neutral facilitators, or invite utilities to take the lead, they should remain involved to ensure the inclusion of a wide range of stakeholders, including ratepayer advocates, developers, environmental organizations, trade associations, technical experts, and electric customers.

• For wires-only utilities, also consider including the full range of wholesale market participant stakeholders.</td><td>• Nonprofit utilities can use NWS as opportunities to engage and educate consumers, co-op members, and municipal customers to ensure their support and participation.</td></tr>
</table>

2. INTEGRATING NWS INTO STANDARD UTILITY OPERATING PROCEDURES

Utility procurement practices, organizational structures, and expertise are currently designed to efficiently procure traditional infrastructure solutions. Adjustments need to be made if utilities are to fully capture the benefits of non-wires solution opportunities. While specific NWS pilots and individual project case studies have garnered attention, more focus on how utilities can standardize, operationalize, and streamline planning and procurement for NWS is necessary. This will allow for the fair comparison of NWS against traditional approaches and for effective engagement of non-utility market participants to best meet regulatory and utility-level objectives.

a) Consolidate accountability for NWS within a single interdisciplinary utility team in order to facilitate fair assessment between different approaches

If NWS are to become key tools in the utility planning toolkit, utilities need to create NWS teams that are fully integrated into the utility's business-as-usual operations and that are directly involved in the planning process, rather than have niche departments focused on one-off projects.

To best support creative and practical NWS, utilities can design their internal organizational structures to promote effective communication between planning, procurement, and DER experts. The process of planning for, procuring, and implementing NWS is complex, requiring cross-functional and interdisciplinary communication among utility departments that may not be accustomed to collaborating. The relative nascence of NWS means that no one department or function within the utility holds the institutional knowledge of how to operationalize a successful NWS program. Utilities motivated to build that internal competency, and ultimately integrate non-wires solution projects into their business model, will need to develop a more comprehensive approach.

While some utilities have relied on internal champions throughout their organization to drive their non-wires solution efforts, that decentralized approach is difficult to sustain. Another reason why non-wires solution projects fail to be properly operationalized into the utility's core business model is that NWS teams are often housed in "utility of the future" or "innovative solutions" groups, which typically generate pilots but not business-as-usual programs.

Instead, utilities should establish a cross-functional team composed of employees with backgrounds in areas including: electric supply, distribution planning, permitting and interconnection, energy efficiency and customer programs, system standards, policy, internal strategy, contracting, and procurement. Not only are these cross-cutting teams more likely to consider NWS in a holistic manner, but they may be more bold and innovative working in concert than if responsibility for NWS were spread throughout the utility organizational structure. Some examples of utilities that have developed cross-functional teams include:

- Pacific Gas & Electric's Grid Integration and Innovation group
- ConEd's Distributed Resource Integration team
- National Grid's Customer Innovation and Development department
- New York Power Authority's Clean Energy Business team
- Southern California Edison's Integrated Innovation and Modernization team
- Arizona Public Service's Customer Technology and Product Development team

A more centralized NWS team also represents an opportunity to streamline processes and create efficiencies to deploy NWS faster. When planning and procuring for various non-wires solution projects is spread across multiple departments (e.g., energy efficiency in customer programs, battery storage in DER solutions), each will have different processes for its various activities. These siloed approaches inhibit the utility's ability to develop and execute comprehensive NWS to meet its grid planning needs. Integration of NWS groups into the utility's business-as-usual processes is an important element for creating a successful NWS program, but absorption of NWS teams into traditional wires groups carries a risk that consideration of NWS projects becomes perfunctory. Utilities should strike the right balance between integrating NWS groups into the core business of the utility while keeping the team's reporting lines distinct enough to ensure against any internal bias toward wires solutions. In practice, some utilities have an NWS team as a separate group within distribution planning, while others have opted for a distinct NWS group with a reporting line outside of distribution planning.

b) Allow for both utility- and provider-led integration of diverse technologies to meet grid needs

Developing a non-wires solution project to resolve a particular grid issue often requires assembling a portfolio of technologies that collectively address the need. Both utilities and third parties can play the role of integrating the various non-wires solution components to fashion a comprehensive portfolio solution.

Many utilities favor playing this integration role because they are most knowledgeable about the grid and have ultimate responsibility for its proper management. These utilities want to ensure that they are forming NWS that not only address a specific grid issue, but that also align with the utility's role in ensuring overall grid reliability and safety. The utility-as-integrator approach can lower barriers to entry for developers participating in NWS since they can bid on discrete pieces of the overall solution rather than be expected to put forth a comprehensive portfolio of solutions when they may not have the capacity or technical know-how to do so. By offering components of the non-wires solution portfolio to bidders, utilities can help animate a wider non-wires solution vendor market.

At the same time, a developer-centric integration role has advantages as well. This turnkey approach may be favorable for smaller or resource-constrained utilities that would prefer third parties to manage the non-wires solution portfolio. Moreover, encouraging developers and DER aggregators to partner together to submit joint bids to utility RFPs may produce solutions that the utility had not envisaged, and that may better address the need and/or be more cost-effective than the utility's approach. Utilities may also not be familiar with new technologies and how they can be integrated to create effective NWS. Technology developers and aggregators themselves may be better positioned to determine how their approaches will work in concert and can present the utility the best optimized and integrated solution.

c) Lay the groundwork to scale successful NWS pilots to full deployment in order to maximize learning and provide the greatest economic benefit

Non-wires solution pilots are an important way for utilities to gain comfort with NWS as effective alternatives to traditional grid infrastructure. Utilities should therefore use non-wires solution pilots to test technologies, operational performance of non-wires solution portfolios, and incentive and contracting terms with developers. The lessons learned from scoping, soliciting, and operating non-wires solution demonstration projects are important elements that can meaningfully shape more permanent NWS programs.

Still, there is a risk that utilities spend too much time launching multiple non-wires solution pilot projects without incorporating pilot learnings into more permanent grid-planning procedures. Running too many pilots may discourage developer participation in the absence of a clear market for their services. Instead, defined protocols of transitioning pilots to programs are critical if utilities are to consider NWS in a more systematic way as part of their business-as-usual operations.

Pilots should therefore be structured in the context of a larger plan aimed at solidifying NWS as part of the standard utility operating procedure. To most effectively do so, utilities should establish a forward-looking process of pilot design that builds on previous pilot results and has technical or market-design elements to test so that the cumulative results can roll up into building an NWS program at scale.[48]

Moreover, there is an opportunity for early movers in the NWS sector to share results of their pilots and demonstration projects to help spark market growth. Socializing these results more broadly can help utilities in other jurisdictions incorporate learnings without running duplicative pilots, and focus their own pilot design on more discrete issues relevant to their particular operations. Wider adoption of non-wires solution technologies and a deeper understanding of their benefits will fundamentally help address a key barrier and attract more participants to grow the market. Ultimately, utilities have to make a demonstrated commitment that the goal of non-wires solution pilot projects is for NWS to be an integral part of the planning processes. Without that explicit commitment, responsible staff won't have the incentives to explore and refine non-wires solution projects in a meaningful way.

FIGURE 7

MARKET-SPECIFIC CONSIDERATIONS FOR BEST PRACTICE RECOMMENDATIONS FOR UTILITY PROCESSES

RECOMMENDATIONS FOR UTILITIES	VERTICALLY INTEGRATED UTILITY	WIRES-ONLY UTILITY	CONSUMER-OWNED AND NONPROFIT UTILITIES
CONSOLIDATE ACCOUNTABILITY FOR NON-WIRES AND TRADITIONAL SOLUTIONS WITHIN A SINGLE INTERDISCIPLINARY TEAM WITHIN THE UTILITY	• VIUs can leverage existing expertise within the utility by drawing professionals from representative teams.	• Wires-only utilities can leverage existing expertise within the utility by drawing professionals from representative teams. • Since wires-only utilities don't own generation, the team may also consider bringing in representatives from market operators or external parties responsible for generation.	• Given resource constraints, interdisciplinary teams at nonprofit utilities are more likely to have lean structures with a smaller number of individuals responsible for integrated job functions and serving as internal champions for NWS.
ALLOW FOR BOTH UTILITY- AND PROVIDER-LED INTEGRATION OF DIVERSE TECHNOLOGIES TO MEET GRID NEEDS	• VIUs are more likely to prefer to integrate NWS projects because of their comprehensive control and expertise. • VIUs desire for asset ownership (as opposed to third-party ownership) may also drive their preference for integration.	• Wires-only companies are more likely to engage with third-party integrators, especially with regards to non-wires solution projects that are generation focused.	• Given their more limited resources, nonprofit utilities are likely to find more value in third parties playing the integration role and providing turnkey solutions.
LAY THE GROUNDWORK TO SCALE SUCCESSFUL NON-WIRES SOLUTION PILOTS TO FULL DEPLOYMENT	• Utilities should ensure pilots are designed by an integrated NWS team and that pilot results will meaningfully inform a holistic strategy for non-wires solution deployment.		• Nonprofit utilities should consider prioritizing learning from pilots done elsewhere, given their limited ability to run multiple pilots. • Co-ops and munis can share learnings via trade associations like the National Rural Electric Cooperative Association, or city government networks.

3. EMPLOYING HOLISTIC PROCESSES FOR NWS PROCUREMENT

Even with the right combination of incentives and mandates, robust distribution planning, and a utility team dedicated to NWS, the practical procurement of NWS is still a complex challenge. Well-designed solicitations and/or other procurement practices are critical to ensure that market participants have the opportunity to offer their solutions.

Current utility procurement practices need to be reexamined to determine whether they effectively support non-wires solution sourcing. In this emerging market, developers require more access to grid and customer data than is required for traditional solutions. Similarly, utilities will need additional information from solution providers to verify the technical feasibility of their proposed solutions projects and to perform benefit-cost analyses.

a) Utilities should consider the range of options for sourcing NWS

There is a range of possible procurement strategies for utilities to consider, but the following three are the most common: customer programs, pricing mechanisms, and competitive solicitations.[49] In practice, there can be overlap between these options and, in some cases, all three approaches can be used simultaneously.

The three NWS sourcing options are not mutually exclusive

Utilities can use all three non-wires solution sourcing options simultaneously to achieve project outcomes. In its Brooklyn Queens Demand Management (BQDM) program, ConEdison used all three approaches to make progress toward its 52 MW load reduction target, including running a competitive auction, augmenting existing customer programs and tariff-based programs, and releasing competitive RFPs.

In addition to using multiple approaches in one project, the distinctions between the three types of procurement (customer programs, pricing mechanisms, competitive solicitations) are often not distinct. GridSolar managed the procurement of a non-wires solution for Central Maine Power to defer a transmission project in Boothbay, Maine. In its technology-agnostic, competitive solicitation, GridSolar awarded contracts to providers of energy efficiency, demand response, and distributed energy resources. Whereas energy efficiency and demand response might typically be considered customer programs, they were procured in this non-wires solution through a competitive solicitation.

Similarly, there are many examples of hybrid pricing and customer programs. For example, Green Mountain Power (GMP) in Vermont provides customers with a lower rate structure for separately metered water heaters (**Rate 3**) if they agree to let the utility shut off their water heater at critical times. The shutoff component of this rate structure would independently be considered a demand response customer program, but GMP has inextricably bundled it with pricing.

Developing frameworks to determine which options are best suited for common use-cases can help utilities make decisions more quickly, and at scale. To help inform these frameworks, descriptions of the three primary sourcing options are provided below.

1. **Customer programs** encompass demand-side management offerings in which the utility compensates customers for participating in measures including energy efficiency, device-enabled demand response programs (e.g., smart air conditioning or smart thermostat programs), pricing-based demand response programs (e.g., peak-time rebates), and behind-the-meter generation and storage.
2. **Pricing mechanisms** involve changes to customer tariffs, including time-of-use rates, demand charges, critical peak pricing (CPP), variable peak pricing (VPP), real-time pricing (RTP), net-metering (NEM), feed-in-tariffs (FITs), and New York's Value of DER (VDER).
3. **Competitive solicitations** are standalone procurements in which a utility asks the market to competitively offer solutions, typically through a request for proposals (RFP) or an auction process.

There are several factors that inform which category or combination of categories a utility pursues to source NWS:

- **Scope of procurement:** Competitive procurements are best suited to larger projects, due to high, fixed transaction costs. A utility may choose to bundle together several smaller needs into one procurement effort that spans a larger geographic area. This approach might open up additional solutions, such as software solutions, which may be more feasible in certain instances, for example when applied to several feeders rather than one.
- **Timeline:** The choice of procurement option is impacted by the amount of time available before the grid need. For example, to meet a grid need with a short lead time, a utility should prioritize time-to-operation and consider leveraging existing customer programs or issuing an expedited RFP. Expansion of existing pricing to a new geographic area within the service territory, such as peak time rebates or critical peak pricing, may also be possible to implement quickly, but new pricing or rate changes may require lengthy regulatory approval processes. The nature of the solution proposed will also influence the speed of procurement. Behind-the-meter solutions—whether competitively solicited or implemented through customer programs—may require longer timelines due to uncertainty around how long it will take for the required number of customers to opt in. Front-of-the-meter solutions sourced through competitive solicitations face risks in land acquisition, permitting, and interconnection that could delay their deployment, however there are examples in which expedited procurement and approvals have led to solutions coming online expeditiously.[50]
- **Project complexity:** Pricing mechanisms and customer programs are most suitable for standardized projects, where targeted technologies can be packaged into a customer offering. In order to maximize customer understanding and adoption, customer programs and pricing mechanisms must be relatively straightforward and effortless, although the necessary simplicity can constrain the universe of solutions that are possible.
- **Certainty of need:** Customer programs and modular DER solutions are attractive for addressing needs that are less certain because they can scale and adjust over time. For example, a residential storage program can be designed to roll out over several years, with targets for the number of customers enrolled increased or decreased in response to progress on meeting

the need. This flexibility of deployment can help to avoid stranded assets. Likewise, both technologies deployed through customer programs and DERs can provide a variety of services and may be reprogrammed to meet new or different needs as they emerge. For example, storage that originally provided load reduction on a strained circuit may be able to meet voltage support needs if the need arises.

- **Risk tolerance:** For the utility, the most obvious risk of non-wires solution implementation is that the projects ultimately do not satisfactorily address a grid need. Customer programs and pricing signals rely on consumer behavior and participation to be successful, creating a potential execution risk for utilities. Strategies to mitigate the risks associated with customer participation are common, including adding technologies that automatically respond to grid needs, such as smart thermostats and smart air conditioners. Utilities can also use data from existing customer programs and tariffs to provide a more accurate assessment of customer responsiveness. Competitive solicitations can be structured to balance risk between utilities and developers according to a utility's risk tolerance. A portfolio of customer programs, pricing, and solicitations can help to mitigate the risk associated with any single type of procurement. Additional recommendations for considering risk in solicitations are provided in the **NWS Contracting Considerations section** on page 70.

1. Customer Programs

Creating new or expanding existing customer programs can be an effective way to meet an identified grid need. Customer programs can be targeted to geographic areas and to customer types (e.g., high-usage customers), which makes them well-suited for non-wires solution applications. Customer programs can also be structured to provide different payments according to the severity of need across the service territory. ConEdison segments its customers participating in the **Distribution Load Relief Program** into two tiers according to location, with Tier 2 participants compensated $8/kW/month more than Tier 1 participants.

Many customer programs provide direct benefits for participants. For example, peak-time rebate programs provide financial incentives to customers who reduce their loads during peak times, but otherwise do not affect prevailing rates. Other programs offer customers new benefits in exchange for grid services. For example, Green Mountain Power offers its residential customers in Vermont eight to 12 hours of backup from energy storage for $15/month in exchange for control of their battery to reduce load during peak events.[51]

Despite delivering clear customer value, it can be difficult and expensive to secure high levels of customer adoption in targeted geographic areas, and expanding the geographic reach of customer programs may not always be technically feasible. To increase the likelihood of success, customer programs require clearly delineated partnerships between utilities and technology providers. Marketing and comarketing should clearly define the relationship between the utility and developers to ensure that customers trust and adopt potential solutions. For new customer programs, the utility can include an offer of customer engagement support in its solicitations to market participants. For example, Pacific Gas & Electric (PG&E) has offered customer engagement and lead generation support to bidders in their solicitations for non-wires solution pilots.[52]

2. Pricing Mechanisms

Pricing mechanisms can also be a powerful tool in the non-wires solution toolbox. Utilities can use different types of time-of-use rates, demand charges, and peak pricing to encourage load shifting or load reduction and support deferral of infrastructure investments. Pricing mechanisms such as net metering, feed-in-tariffs, and New York's VDER, can be used to compensate DER generation and offset load. Design of pricing should reflect grid needs, be technology agnostic, and align with policy goals. Rate changes require regulatory approval, and any localized pricing must consider ratepayer impacts across the utility's service territory.

The necessity to prove to regulators that new rates won't adversely shift costs across the service territory can make it difficult to target rates to specific feeders or substations. Nevertheless, San Diego Gas & Electric piloted an opt-in time-of-use rate that included premiums for use during the top 200 peak hours on each circuit.[53] Circuit peaks were called for each customer based on his or her location, and resulted in rate increases of $0.19/kWh above baseline during peak hours.[54] This pilot was intended as a proof of concept and had a small number of participants but provides an early example of what rates designed to meet distribution system needs might look like.

Implementing tariffs may also require significant lead time to obtain regulatory approval and mitigate ratepayer impacts. As an extreme example, the time-of-use rate concept was first introduced in California following the state's 2001 energy crisis, and the formal rate reform process was not initiated until 2013. Default time-of-use pricing for residential customers will finally be implemented in 2019.[55] Voluntary rates can be easier to implement and, though it can be challenging to recruit customers, some utilities have had noted success: Over 50% of Arizona Public Service's residential customers are enrolled in its voluntary time-of-use-rate, which helps to reduce summer peak loads.[56]

To develop innovative location-based tariffs, utilities can build on successes in implementing differential compensation for distributed generation. Many states have seen a shift away from net metering, which compensates distributed generators at retail rates. Some of these states are shifting toward models like New York's VDER, which compensates distributed generators based on where and when they generate electricity. The **VDER** concept is anchored in a "value stack" with components that include avoided cost of carbon emissions, cost savings to customers and utilities, and other savings from avoiding expensive capital investments. Mechanisms like VDER can provide incentive for customers to install DERs where they provide the most value to the grid and help to mitigate the need for potential infrastructure upgrades.

3. Competitive Solicitations

Solicitations refer to approaches where an open, competitive process asks bidders to provide solutions for a specific need. Typically, competitive solicitations are formulated as an RFP or an auction. In both approaches, solutions are evaluated against one another on technical feasibility and cost. In an RFP process, solutions may also be compared according to qualitative factors, such as community or environmental benefits. In a non-wires solution solicitation, the issuer may select a single bid or a portfolio of bids.

Auctions have been used to procure DERs in California and specifically to procure a non-wires solution in New York. A successful auction requires a fairly mature market, with a pool of prequalified bidders that have a good understanding of the solicitation requirements and expectations. Auctions may provide additional transparency to the market because the clearing price is often made public, whereas the cost of winning bids for RFPs is released less frequently. While an auction is efficient, it is also a blunt mechanism: auctions value different types of resources on the basis of price alone and may not allow for comparing the unique attributes of those resources. Additionally, auctions may require significant development time to design the structure and to qualify vendors.

For its Brooklyn Queens Demand Management (BQDM) program, ConEdison procured 22 MW of peak load reduction (out of its 52 MW project target) through a reverse auction. The auction started with a price ceiling, and solutions providers decreased their bids in real time until the desired MW of load reduction was met; all bidders were then compensated at the clearing price. The risk of an auction with a clearing price is that the utility may overpay for resources; the clearing price of $988/kW-year was set by energy storage, one of the more expensive resources, and was far above the previous prices ConEdison had paid for other demand response resources.[57]

RFPs have been used to procure many non-wires solution projects, and most closely mirror traditional utility procurement processes. In an RFP, the non-wires solution procurer will publicly issue a package of information including data about the need, descriptions of the solutions, instructions for response, timelines, and criteria for evaluation. Based on this information, solutions providers develop bids according to instructions. The issuer of the solicitation evaluates the bids it receives and selects a bidder or portfolio of bidders.

Best Practices for Competitive Solicitations

The remainder of this section will focus on procurement of NWS through **competitive solicitations using RFPs**, in large part because it has been the most prevalent sourcing strategy used for non-wires solution projects thus far. Customer programs and pricing mechanisms are relatively nimble and flexible, allowing utilities to develop new implementation strategies fairly easily. In contrast, the traditional utility RFP process has many rules, processes, and standards that create institutional barriers to innovation and adaptation. To adapt this traditional process to ensure RFPs for NWS are most effective, we focus on two categories of best practice competitive solicitation recommendations:

1. **Process enhancements:** considerations for improving the methods by which non-wires solution solicitations are developed
2. **Best-fit technical approaches:** considerations for designing the content of an RFP to maximize the probability for technically feasible and cost-competitive results

1. Solicitation Process Enhancements

Soliciting non-wires solution projects requires increased coordination between a complex set of stakeholders. RFP development and evaluation processes can be improved to engage and leverage the expertise of complex sets of stakeholders, build the market's capacity to participate, and transparently share lessons learned.

a) Engage developers and other stakeholders throughout the process

Stakeholder engagement is critical at every step of the non-wires solution solicitation process to ensure creative solutions; competitive and technically feasible bids; and that stakeholders understand how a project provides value within the targeted geographic area. Whereas a traditional procurement process typically involves some level of information asymmetry in favor of the utility to ensure a bidding process remains competitive, non-wires solution procurement requires that utilities and developers spend significant time learning from one another. Maximum transparency and frequent communication are necessary at this early stage of market development to ensure that precedents determined now set the market up for future success and scale. Specific stakeholder engagement actions should be considered before, during, and after running a competitive solicitation process.

Items to Address Prior to an RFP Release

Engagement with developers prior to RFP development can be extremely valuable for all parties. Developers can articulate the types of data and information that would best position them to develop meaningful solutions, and they can provide valuable input on the initial feasibility of utility-proposed solutions. Early in the development of a more standard RFP process, developers should be given the opportunity to play an educational role, providing information to utilities on the latest DER technologies and their various applications.

Engagement with other stakeholders prior to RFP development can also help utilities design more durable solutions that deliver maximum customer and grid benefit. For example, earlier this year, PG&E released a request for offer (RFO) for its Oakland Clean Energy Initiative (OCEI), which seeks to procure local resources in combination with some substation upgrades to compensate for the retirement of a fossil fuel generator and meet local transmission reliability needs.[58] PG&E worked with the community extensively in the development of the proposal, including local labor, environmental groups, and the Maritime Port of Oakland, both to identify feasible projects and to ensure the community would benefit. Since NWS are often dependent on customer participation, it is extremely helpful to understand their needs and concerns to structure an effective solution. Community stakeholders and/or customers in the community may also hold key resources that can be used for a non-wires solution, such as land or rooftops. ConEdison has worked continuously with the New York City Housing Authority to identify opportunities for load reduction in its facilities, which represent a large portion of load in the BQDM project area.[59]

Before issuing an RFP, a utility should understand the size, technology, and time limits that are likely to eliminate potential developers, and structure the solicitation to lower barriers to entry. For example, New York lengthened RFP developer feedback response time from six weeks to 10 weeks, which was intended to allow developers with fewer resources more time to compete effectively. To the greatest extent possible, utilities should also seek to leverage their own assets to reduce barriers to entry for non-wires solution developers, such as utility-controlled land and streamlined interconnection processes. In its OCEI RFO section for utility-owned storage, PG&E states that offers will be considered for projects sited on PG&E-owned land, and that PG&E will lead on interconnection and some aspects of permitting for these projects.[60] To ease the interconnection process, utilities should provide guidelines or relevant examples of the types of support they may be able to provide, and which upgrades and equipment are likely to be the responsibility of bidders.

Utilities may also choose to explore alternative solicitation vehicles in addition to RFPs or RFOs. For instance, a request for information (RFI) can occur prior to an RFP as a formal way to collect information from potential bidders. RFIs can be effective in helping the solicitation issuer identify specific questions or data that would be valuable to use in the solicitation. ConEdison, for example, released an RFI in advance of its BQDM program to better understand how to effectively craft its solicitation.[61]

Key Considerations During the Solicitation Process

Solicitation opportunities should be posted in a central, public repository to maximize bidder accessibility and exposure. Once an RFP for a non-wires solution is released, ongoing contact with bidders is essential. Best practices from experience to date include ongoing utility collaboration with developers on non-wires solution RFPs through monthly pre-bid conference calls and webinars designed to encourage developer questions. These conversations provide an opportunity for bidders to clarify aspects of the RFP and better understand the utility's goals, which improves the likelihood that utilities will receive bids that align with their vision. After bid submission, the utility should continue this two-way communication and allow bidders time to address any information deficiencies or questions regarding their bids.

Following the initial RFP release, it can be helpful for utilities to screen bidders based on their intent to bid. Qualified vendors move forward in the solicitation process based on their technical readiness, creditworthiness, access to capital or history financing similar projects, and a willingness to accept the utility's commercial terms. Prequalification creates a more streamlined process that allows utilities to evaluate bids more quickly. The Joint Utilities in New York have laid out sample criteria for vendor prequalification in their Supplemental Distributed System Implementation Plan, including vendor deployment experience, credit requirements, and a first-pass evaluation of the fit of the solution to the need.[62]

During the solicitation process, some utilities create the opportunity for developers to connect with each other and develop integrated solutions. For newer technologies and less mature applications of NWS, developers and technology providers may have more ideas of how to assemble a portfolio than the utility. In its recent non-wires solution RFPs, National Grid included an offer to connect bidders that wish to address one component of the solution with other bidders looking to partner.[63] For developers with fewer resources or experience, this type of offer can provide an opportunity to compete for a piece of the project. For utilities, connecting solutions providers can result in creative packages of products that would not have otherwise been generated.

Important actions to take following bidder selection

Once bids are evaluated and vendors selected, the utility should clearly communicate with all bidders the reasons why their bids were or were not selected. At this critical stage of non-wires solution market development, it is important to provide transparent feedback for all bidders to improve the overall quality of future responses. Scaling NWS will require a large pool of vendors that understand how to deliver products aligned with utility needs.

A utility's release of non-proprietary data or lessons learned following a procurement process can also provide useful market information. Earlier this year, Xcel Energy ran a competitive all-source solicitation process for generation and released to the public anonymized data regarding the cost and number of bidders for each type of technology.[64] This information, specifically the strikingly low cost of renewable resources, generated significant interest and shifted many stakeholder perceptions regarding the cost of these resources. Similar data regarding cost and efficacy of NWS can support the evolving understanding of their value and broaden the marketplace for non-wires solution services.

FIGURE 8

HOW TO ENGAGE STAKEHOLDERS

PRIOR TO RFP RELEASE

- Understand DER offerings and capabilities
- Understand community needs and resources
- Evaluate initial technical feasibility of the proposed project
- Identify technology provider data needs
- Ensure developers understand how bids will be evaluated

DURING SOLICITATION PROCESS

Prescreen the list of bidders to those that qualify
- Answer bidder questions to improve the quality of bid
- Continue to engage bidders through webinars and conference calls
- Connect bidders to one another to foster integrated solutions

AFTER BIDDER SELECTION

- Provide specific feedback to bidders on why they were/were not selected
- Share lessons learned with peer utilities and the public
- Release non-proprietary information that can help move the market forward

b) Consider the role of third parties in procurement

In most non-wires solution procurement examples, the utility has led the competitive solicitation processes including development, release, and selection. If the utility is structured to transparently support the identification, evaluation, and procurement of non-wires solution opportunities at scale, then keeping these functions in-house should reduce transaction costs. However, there are a few reasons to consider moving this function outside the utility altogether:

- Utilities may not have the capacity or risk tolerance to manage a robust non-wires solution procurement process.
- There may be desire from stakeholders for an additional layer of transparency or neutrality in the non-wires solution procurement process.
- Key stakeholders in non-wires solution development may lie outside of the utility.

Several examples exist of third-party involvement in non-wires solution solicitations. In Boothbay, Maine, GridSolar LLC, a private third party, was responsible for the full solicitation and development of a non-wires solution pilot project to defer the need to build a transmission line.[65] GridSolar was given the autonomy to develop the project by the Maine PUC as a result of a settlement contesting a new transmission line proposed by the utility, Central Maine Power. The first non-wires solution in the state, and an early proof of concept for NWS in the US, the Boothbay project entirely removed the risk of project development from the utility. GridSolar was expected to deliver a specified capacity when called upon to do so by Central Maine Power. After three years of reliable operation, the pilot terminated because it became clear that the projected load that had been the justification for the transmission line proposal had not materialized. DER assets that were part of the Boothbay portfolio remained in place or were moved and repurposed. While the consideration of NWS in Maine has since become a legislative mandate, GridSolar's pilot was the validation the state needed to propose this mandate, and to show the utility and ratepayers the value of NWS.

Washington, D.C., is in the process of exploring an entirely new model for NWS identification and solicitation development. In its proposed DER authority model, a neutral, third-party entity would assume all these roles as a complement to the regulator.[66] In many respects, the DER authority resembles a wholesale market model, in which an independent systems operator is responsible for identifying needs and issuing solicitations or creating pricing mechanisms to procure wholesale resources. Some of the advantages of this model are improved transparency (i.e., ensuring that NWS receive fair consideration alongside traditional solutions), and the avoidance of opportunities to use screening criteria to artificially exclude projects (e.g., by a utility splitting traditional grid infrastructure projects into multiple smaller ones that are under thresholds for size or cost that would otherwise trigger non-wires solution evaluation).

Finally, there are states in which a third-party entity may need to play a key role in non-wires solution implementation if it is primarily responsible for designing and procuring customer programs. For example, Energy Trust of Oregon and Efficiency Vermont run competitive solicitations for energy efficiency and customer programs in their respective states.[67] Similarly, the federal agency Bonneville Power Administration considers and implements NWS across the eight western states where it transmits and sells electricity.[68] These organizations will need to play a key role, including maybe issuing the solicitation, in any non-wires solution opportunity that would leverage customer programs.

2. Best-fit technical approaches for solicitation

In addition to solicitation process enhancements, material changes to RFPs will enable non-wires solution providers to participate more effectively. RFPs should provide ample data to bidders accurately describing the identified need and desired performance attributes of the solution, while remaining agnostic to all potential technology proposals. Solicitations should strive for specificity but refrain from being technically deterministic. The following considerations describe key components of solicitations, and how they may need to be altered for NWS.

c) Provide data-rich needs descriptions for the solutions being requested

The foundation of a non-wires solution RFP is the utility's clear articulation of the problem it's trying to solve. To date, most non-wires solution projects have been implemented for load relief needs, though NWS have also been considered for hosting capacity, reliability, and voltage support.[69] Needs descriptions should focus on describing the problem, not the potential solution. Utilities should strive to construct needs descriptions that are not prescriptive and do not presume a particular technical outcome.

It is critical for needs descriptions to include sufficient data to enable developers to design effective solutions. In general, developers are interested in as much data as the utility is willing to provide to develop detailed solutions. More specifically, technology providers seek an understanding of the magnitude, duration, and frequency of the need; granular (hourly or sub-hourly) load profiles; and the grid topology of the affected area. These types of data can be included in solicitation documentation, and, ideally, made publicly available online. For example, all New York utilities' non-wires solution opportunities are listed on **dedicated pages on their websites** and some of their specific solicitations link to public GIS maps including hosting capacity, Locational System Relief Value and Value of DER, and existing distribution assets.

In addition to data that characterizes the grid need, bidders offering demand side management, efficiency, and customer-sited distributed generation are interested in customer demographic data. Breakdowns of commercial and residential customers, building stock information, and aggregated load profiles can be extremely valuable to solutions providers. Utilities should seek to release customer demographic data that enables customer-sited solutions to compete effectively, without compromising customer privacy or data security. For a more complete list of data to be included in an RFP, please reference the **Competitive Solicitation Processes section** on page 58.

Needs descriptions should also leverage probabilistic analysis undertaken in planning processes. Detailing the probabilities for ways in which the need may change over time allows developers to design more flexible, modular solutions. A more probabilistic approach could signal to developers that the utility values flexibility in its evaluation of solutions. Revealing the cost of the traditional infrastructure solution that a non-wires solution would be compared against can be a helpful data point. The decision whether or not to provide the cost-to-beat for NWS has been contentious, with utilities citing concern that bidders could price their solutions just shy of the cost cap, rather than bidding at true cost. While this could lead to suboptimal pricing, it would still lead to NWS that are less expensive than traditional solutions. Furthermore, if the non-wires solution market was sufficiently competitive, concerns of providing a cost to beat would be less relevant because bidders would be sufficiently motivated to bid a cost to compete against each other. From a developer's perspective, this information can be critical to determining whether their proposed solutions are cost-effective. This allows them to more efficiently allocate their resources to participating in solicitations that they know will be successful. In New York, cost-to-beat data is provided on a utility-by-utility and case-specific basis, whereas in California it is supposed to be included as part of the Distribution Investment Deferral Framework.[70]

d) Elaborate performance attributes for solutions rather than technology requirements

Next, an RFP should articulate how the solution is expected to meet the described need. Solutions should be framed in terms of attributes and performance, rather than specific technologies. Technology providers themselves should be able to determine whether their product is a good fit to meet the need, and utilities benefit little by limiting the solution set. The Joint Utilities in New York often include a statement of this technology agnosticism in their RFPs: "This RFP is open to all DER approaches that display the potential to provide load relief in the areas identified."[71]

Solutions descriptions should elaborate the reliability criteria for DERs as part of a non-wires solution. As described in California's Competitive Solicitation Framework Working Groups Final Report, "DERs will need to be able to deliver specified services reliably at very precise locations, at specific times, and in predictable amounts."[72] As a result, reliability and availability performance requirements must be very clearly articulated in non-wires solution RFPs.

Developers must understand if and how utilities intend to dispatch resources to meet a particular need. DER solutions can either be active resources that require signals for dispatch, or passive resources that constantly reduce load or operate independent of utility instruction. Technology providers of active resources need to know how much advance notice will be given prior to dispatch, how signals will be sent, and what the quality of their response should be over a specified time period. These protocols should be designed to meet the grid need without unnecessarily limiting the types of technologies that can respond. The level of control required by the utility, for both dispatch and data visibility, should be made clear to developers. RFP instructions should also indicate how dispatch will account for other services the asset may provide in addition to distribution deferral, such as customer resilience or resource adequacy. For a more complete list of data to be included in an RFP, please reference the **Competitive Solicitation Processes section** on page 58.

Developers should also understand who will be assembling the portfolio of solutions, and whether bids are aimed at meeting the full grid need specified or if they are to be a discrete component of the ultimate solution. In most cases, the utility will organize bids into a complete solution. If DER providers are expected to work with aggregators to design more complete solutions, that should be explicitly stated within the RFP.

e) Provide clear evaluation criteria as part of the solicitation

Utilities should consider updating evaluation frameworks to reflect the range of values that NWS provide, and communicate evaluation criteria transparently to bidders.

Evaluation of non-wires solution bids should first assess the technical feasibility and cost-effectiveness of the proposed solutions. Beyond cost-comparison of technically acceptable solutions, utilities should adapt more comprehensive benefit-cost analysis (BCA) frameworks to reflect the range of benefits that NWS provide. NWS provide local system benefits and avoided costs, which may not be accounted for in existing BCA calculations. Additionally, BCA methodologies can be updated to reflect some of the benefits that are more difficult to quantify, such as emissions reductions, air quality improvements, economic development, and other non-energy benefits to customers and society. Ideally, these values should be incorporated into a single framework that allows for side-by-side comparison of non-wires solution portfolios that include different strategies and technologies.

A utility's RFP should clearly state how bids will be evaluated so that developers can craft solutions that reflect the utility's priorities. Clear methodologies for how solution costs and benefits will be quantified are critical for transparency and bid optimization. Utilities source the most cost-effective solutions when they can draw from a mature and competitive market. Providing transparent evaluation criteria can help build developer trust in the solicitation process and encourage continued participation in the utility's non-wires solution solicitations.

In California, for example, non-wires solution solicitations clearly state bids will be evaluated on a least-cost, best-fit basis. The state already uses the principles of "least cost, best fit" through procurement of renewable portfolio standard resources, local capacity requirements, and other all-source solicitations for resource adequacy. Cost metrics (also included in the solicitation) are first used to assemble an optimized portfolio, which is then reviewed for additional services and potential conflicts, and finally reviewed for qualitative factors such as project viability.[73]

The Joint Utilities in New York use a different approach, and language in their RFPs indicates that the objective of the bid evaluation process is to identify solutions that "provide the greatest overall value to customers."[74] A list of factors by which bids will be evaluated is provided in the RFP itself, including quantitative considerations such as cost, and qualitative items such as timeline and project viability, environmental benefits, and community impact. These factors are explicitly not listed in order of importance, nor given any weighting. The RFPs indicate that the utility's BCA framework will be used to evaluate the bids, but that framework—which is already complex for developers to navigate—is only one of several evaluation approaches that utilities indicate they will use. Therefore, developers have expressed that the BCA framework does not, in itself, provide respondents with sufficient clarity on how non-wires solution bids may be evaluated. From a developer's perspective, this makes it very challenging to prioritize their efforts in preparing their bids or to understand why their proposal was not selected. Within the utility, a framework that requires more qualitative and customized analysis may be difficult to scale if many bids are received.

Further recommendations on structuring these evaluation frameworks can be found in the **Proposal Evaluation section** on page 64.

f) Keep options open for further DER market evolution, including wholesale market participation and/or distribution-level service pricing

As existing grid infrastructure ages and DER adoption accelerates on the distribution system, utilities increasingly face unprecedented challenges—and opportunities—for system management. Forecasting future demand and generation needs is becoming increasingly complex, and utilities should weigh the risk of stranded investment capital in traditional assets if/when grid needs no longer match developments. Not only can DERs defer infrastructure investments, they can also provide a number of other distribution-level services that are uniquely qualified to address emerging grid needs and customer demands. In particular, the flexibility and modularity of DERs should be considered in non-wires solution procurement. Non-wires solution solicitations, for example, could include upper and lower bounds on load forecast estimates, and encourage bidders to show how their solution might be able to scale up or down within the range of projections. Additionally, non-wires solution providers should be encouraged to provide a menu of services their product can offer beyond meeting the current need.

The concept of a distribution services market, though nascent, could expand the marketplace for NWS. Instead of procuring packages of resources to meet specific needs, a mature market would allow a distribution system operator to cultivate a portfolio of DERs that can be called upon to provide a variety of distribution-level services. A distribution services market could also provide utilities with a wider range of available resources if a distribution need arises. Currently, one non-wires solution portfolio is typically required to meet a defined need with a high degree of certainty. However, in a market structure, there is often a redundancy of resources that can provide critical services. In wholesale ancillary services markets for example, many different generators are capable of providing voltage support or frequency regulation as there is no single asset responsible for maintaining grid reliability. While this concept is more likely to be implemented in deregulated states that have wholesale energy markets or states with high DER penetrations, it could be applied to any type of utility with appropriate regulatory or board approval.

Many value streams that DERs offer at the distribution level—such as phase balancing, voltage management, hosting capacity, shaping EV and building electrification loads, and local resilience—are not currently well-quantified. For example, using NWS for hosting capacity is an increasingly relevant application that was included in California's Distribution Resource Plan Demo D pilots.[75] In its CPUC proposal after the solicitation evaluation concluded, PG&E requested permission to forego selecting any bidders. In its summary of lessons learned, PG&E relayed that bidders had difficulty determining the value of hosting capacity, which was reflected in bids that came in at higher costs than PG&E expected. For behind-the-meter solutions, the terms of hosting capacity services were often in conflict with customer time-of-use rates: solar generation often occurred during higher-priced hours, so shifting loads to better utilize solar imposed new costs to customers.[76]

As markets mature for capturing the value of DERs, RFPs will increasingly have to specify the rules for participation across programs. California has an active working group in its Integrated Distributed Energy Resources proceeding that is focused on the concept of "incrementality," or how to determine if a DER that is already being compensated through an existing program is also able to provide services and be compensated under a new solicitation. For example, PG&E asks solicitation participants to specify if the assets they are bidding into an RFP already participate in other utility programs. PG&E uses a table to explain the concept of providing a solution that is incremental to other tariffs and solicitations. For instance, an existing energy efficiency program would have to specify how adding a new component of a program or increasing incentives would materially enhance uptake to be considered incremental.[77] This framework should be reevaluated on a recurring basis to surface any unintended consequences such as excluding DERs used for NWS from other compatible value streams.

Rules and contracts developed for new solicitations should ensure that resources are not being double-counted in a way that could affect project reliability, while leaving room to evaluate the best use of resources in a future with different grid needs. Frameworks for incrementality or participation in multiple programs should also be designed to ensure they do not unnecessarily restrict NWS from access to critical subsidies. Rather than a formal incrementality framework, ConEdison has provided a statement on cross-program participation in its Non-Wires Alternatives Program Agreement,[78] which states that assets are eligible to receive compensation from other programs provided they meet the non-wires solution performance criteria and are not compensated at a value greater than their costs.

g) Lay out clear requirements in project contracts to fairly allocate risk and ensure operational reliability

The risk profiles for NWS differ from traditional grid infrastructure in some key aspects including dispatch control, performance standards, and payment structures. Utility procurement contract templates should be adapted to account for these differences. At the same time, these contracts need to strike a balance between giving utilities sufficient confidence that NWS will reliably deliver critical grid services, while ensuring that the risk placed on developers does not result in cost-prohibitive bids or otherwise stymie the market. Balancing these risks in non-wires solution contracts has been challenging for utilities and developers, and there are currently few examples of standard non-wires solution contract structures. To support more standard structures, contracting considerations for terms describing dispatchability, payment, performance, and construction can be found in the **NWS Contracting Considerations** section on page 70.

FIGURE 9

MARKET-SPECIFIC CONSIDERATIONS TO ENSURE HOLISTIC NWS PROCUREMENT PROCESSES

<table>
<tr><th>RECOMMENDATIONS FOR PROCUREMENT TEAMS</th><th>VERTICALLY INTEGRATED UTILITY</th><th>WIRES-ONLY UTILITY</th><th>CONSUMER-OWNED AND NONPROFIT UTILITIES</th></tr>
<tr><td>USE DIVERSE APPROACHES FOR ENABLING NWS, INCLUDING PRICING MECHANISMS, EXPANSION OF CUSTOMER PROGRAMS, AND COMPETITIVE SOLICITATION</td><td colspan="3">• Utilities in each market should consider all three procurement options and evaluate their relative merits to best address a given system need.
• Attention should be paid to the relative transaction ease of pricing and customer programs compared to solicitations, which might make the former more desirable to resource-constrained nonprofit utilities.</td></tr>
<tr><td>DEVELOP A COMPREHENSIVE COMPETITIVE SOLICITATION PROCESS THAT PROVIDES AMPLE DATA AND IS TECHNOLOGY AGNOSTIC TO ENSURE MEANINGFUL BIDS</td><td>• VIUs may be able to structure non-wires solution procurements to align with their core business model if regulators approve addition of new assets to their rate base. Therefore, VIUs have a strong incentive to design user-friendly and data-rich RFPs to stimulate strong responses.
• VIUs also are likely to have the requisite institutional capacity to comprehensively draft and evaluate the range of technologies proposed in non-wires solution offers.</td><td>• Depending on the level of regulatory support for NWS, wires-only utilities can leverage NWS procurements to expand ownership of different asset types (like storage) or increase the rate base by including new expenditure classes.
• Wires-only utilities may lack familiarity with contracting structures for ownership of some technologies (like distributed generation) so procurement teams may need to rely on external precedents or consultants.
• If wires-only utilities do not own NWS, they may need to pay greater attention to the participation of assets in wholesale markets to avoid conflict in overlapping provision of services.</td><td>• Co-ops and munis may have difficulty attracting bids from developers given the small size of their non-wires solution needs. Consider aggregation of needs across multiple co-ops and munis.
• Many co-ops face the issue of self-generation caps due to contracts with G&Ts, potentially limiting the suitability of some technologies for NWS.</td></tr>
</table>

02

SECTION 2: IMPLEMENTATION GUIDELINES

IMPLEMENTATION GUIDELINES

Having detailed best practice frameworks for developing robust NWS programs, we turn from outlining enabling conditions to practical guidelines that regulators and utilities can adopt to procure non-wires solution projects. This section includes detailed considerations for the four central elements underpinning successful implementation of NWS:

1. **Screening criteria** to identify potential non-wires solution projects
2. **Competitive solicitation** processes that lead to meaningful responses
3. **Evaluation frameworks** to determine if NWS are viable and competitive
4. **Contract terms** attuned to non-wires solution project characteristics

1. SCREENING CRITERIA

Screening criteria for NWS can help prioritize utility procurement efforts on projects that offer the highest value and likelihood for developer bid success. Screening criteria can thus help grow the still-nascent market for NWS, minimizing false starts and pursuit of marginal opportunities. In the long run, as utilities gain more non-wires solution experience, screening criteria should evolve to be more inclusive of a wider universe of potentially viable NWS.

With NWS still fairly nascent, planners can most efficiently identify viable non-traditional solution opportunities by adapting existing planning practices to screen for non-wires solution suitability. Typical planning involves regularly determining system needs based on review of load forecasts, asset conditions, system reliability, load serving capability, and other relevant operational data. Once needs and timing are identified, planners estimate costs for a range of possible solutions and select the most cost-effective option to include in capital budgets. This traditional process can better support NWS if planners simply used screening criteria to determine if NWS should be included as part of the potential solution options considered. Instead of actively pursuing NWS for every grid need, screening allows utilities and developers to focus on the most viable non-wires solution projects, ensuring more productive market engagement.

Any criteria used for screening should evolve over time to avoid artificially limiting the market as more non-wires solution applications are proven. Criteria should also be applied as heuristics guiding decisions to further evaluate NWS rather than as rigid boundaries used across all situations. Rhode Island embeds flexibility in its screening by clarifying that utilities can use their discretion to pursue NWS even if a need does not pass one or more of its criteria.[79] New York regulators have also noted that screening criteria may unreasonably limit non-wires solution opportunities and that utilities should consider public policy goals and other justifications for pursuing NWS despite screening results.[80]

Development of screening criteria can build upon existing frameworks

A range of approaches has been taken to develop and integrate screening criteria into planning processes. States or utilities beginning to engage with NWS can develop their own screening criteria that build on established precedents. Descriptions, examples, and critical considerations for five illustrative screening criteria categories adopted by different jurisdictions are provided below.

FIGURE 10
COMPARISON OF CATEGORIES INCLUDED IN VARIOUS DISTRIBUTION SCREENING CRITERIA

SCREENING CRITERIA CATEGORY	CATEGORY DESCRIPTION	CALIFORNIA	NEW HAMPSHIRE (LIBERTY UTILITIES)	NEW YORK	RHODE ISLAND	VERMONT
1. TIMING	Evaluate different non-wires solution options based on different need dates	✓	✓	✓	✓	✓
2. ECONOMIC VALUE	Prioritize NWS for high-value projects		✓	✓	✓	✓
3. PROJECT TYPE	Narrow scope of non-wires solution analysis to certain system needs	✓		✓		✓
4. ASSET CONDITION	Exclude specific system needs from non-wires solution analysis		✓		✓	
5. PROJECT SIZE	Limit non-wires solution analysis to smaller-scale projects		✓		✓	

1. Timing

NWS should only be considered where they can be deployed in time to address a need

Recognizing that it takes time to procure NWS, a timing screen can be used to exclude consideration of NWS for grid needs that are expected within a certain time frame. Initially, NWS might only be pursued when there is both enough time to address a need by deploying a non-traditional solution and enough contingency to deploy a traditional solution in the event the non-wires solution project is delayed. As utilities become more familiar with implementing NWS and developing operational contingency plans, they should consider shorter time screening thresholds for specific projects. Utilities may also want to use a timing threshold to exclude needs identified particularly far in the future due to the increased forecast uncertainties.

Developing specific criteria

To determine the appropriate amount of time to serve as the threshold for non-wires solution consideration, a utility can look to its historical experience procuring solutions for specific types of needs and then add extra time for a contingency margin. It can delineate components of solution implementation (project identification, solution sourcing, evaluation, approval, deployment), and focus on how long each step is expected to take for non-wires and traditional solutions. As an illustrative example, if, over the last five years, it took 12 months on the average for a utility to deploy traditional projects to address a 5 MW load relief need, that utility might want to exclude NWS for similar identified needs that are less than 24 months in the future. The 24-month threshold is thus designed to assure the utility that it could pursue an NWS project with enough contingency to deploy a traditional solution if necessary.

Rhode Island and Liberty Utilities in New Hampshire use timing thresholds in this way, requiring NWS consideration only for needs at least 30 or 24 months in the future, respectively. Timing criteria can also be made more flexible by differentiating thresholds by non-wires solution project type, size, or sourcing mechanism. For example, New York uses a criterion that differentiates timing thresholds based on project size, and California differentiates based on project types. California investor-owned utilities' recent Distribution Deferral Opportunity Reports note that they are prioritizing NWS for needs at least 36 months out. The state's Distribution Investment Deferral Framework however notes that even short-term needs within 18 months could potentially be addressed by NWS, granted non-RFO sourcing mechanisms and expedited regulatory approvals. This flexibility is important since some non-wires solution technologies like storage can, in certain circumstances, be the best and fastest to deploy, as Southern California utilities demonstrated with its expedited procurement of 70 MW of storage in six months in response to the 2015 Aliso Canyon gas leak.[81]

Considerations

Timing criteria should be designed keeping in mind that different DER technologies come online in different timeframes. It is possible that storage can be deployed very quickly but implementing other NWS, like new geo-targeted demand-side management programs, may take longer to engage and recruit customers. Contingency time is also a critical consideration that utilities need to incorporate into timing thresholds. Non-wires solution project milestones should be delineated in contract structures so that utilities can track deployment and ensure reliable service via either the non-wires solution or a contingency strategy if the non-wires solution is delayed.

2. Economic Value

A screening process should prioritize the highest-value opportunities for NWS, often corresponding to situations where the traditional solution is very expensive

This screening category uses cost thresholds to exclude NWS from consideration for minor, inexpensive projects in which high transaction costs could disproportionately disadvantage them. Since NWS are only pursued if they are cost-effective, this screen helps target the highest-value opportunities where NWS can avoid sufficient traditional expenditures to be cost-competitive, even including the potential additional costs associated with procuring them.

Developing specific criteria

Utilities should reference their historical capital planning experiences to identify average costs for traditional projects that have been approved to meet particular system needs. For example, a utility could inventory all the distribution investments it made over the past five to 10 years to identify typical cost parameters for certain categories of projects. Ideally, planners would then use these parameters to develop unique cost thresholds for different project categories. For example, Rhode Island's screening framework states that cost floors should vary across different project types and timeframes. New York utilities similarly have differentiated thresholds for "small" and "large" project types. Utilities in Vermont differentiate cost thresholds between distribution and transmission projects, and furthermore they include consideration of the relative cost differential between a traditional solution and the non-wires solution rather than just an absolute threshold for the cost of the former.

Considerations

Utilities can and do make exceptions to this economic screen for pilot or other demonstration projects intended to identify issues and build comfort with unfamiliar technologies. The thresholds established by utilities should therefore be flexible so they don't exclude NWS that may be compelling despite addressing needs where traditional solutions may be inexpensive. Given the range of potential non-wires solution benefits, it may be reasonable for utilities to recommend—and regulators to approve—NWS for environmental or planning flexibility purposes even if they are below screening cost thresholds.

Although cost thresholds have varied widely across sets of screening criteria, regulators can support more uniform threshold development by providing utilities with threshold determination methodologies or other guidance. Regulators can also review threshold determination documentation to verify that the utility's analysis is rooted in actual business practices. When reviewing capital investment plans, regulators can further ensure that the full costs to address a system need are not artificially segmented to fall below cost thresholds and avoid non-wires solution consideration.

3. Project Type

Certain investment categories can be deprioritized from non-wires solution consideration

Utilities spend billions of dollars each year maintaining the distribution systems that provide the last mile of electric service to end-use customers. Some of these investments, for needs like capacity constraints, are more suitable to defer or avoid by implementing NWS than others like reactionary repair of damaged equipment where there is limited time for planning. By categorizing different types of needs and assessing the ability for NWS to solve them, a project type screen can help utilities prioritize non-wires solution consideration for those categories where NWS would be most capable of addressing needs.

Developing specific criteria

Utilities typically categorize investments to meet distribution grid needs in their capital budgeting processes. For example, in their Supplemental Distributed System Implementation Plan, New York utilities summarize capital investment projects into 11 different categories including load relief, asset condition, and non-transmission or distribution infrastructure.[82] To determine the applicability of NWS to each project category, the utilities define the types of services needed to address each. Certain categories like "public requirements," in which existing facilities must be relocated to accommodate rights-of-way, were deemed not relevant for NWS since the investment is for a service unrelated to capacity or performance. Similarly, the "non-transmission or distribution infrastructure investment" project category was not considered applicable for NWS because the investment is for things like telecommunications or other such services that support grid operations rather than grid operating infrastructure. Based on their analysis, New York utilities considered load relief and reliability the most conducive to NWS but remain open to opportunities in which NWS can provide value across most other categories.

California has similarly categorized investment types for system needs, and notes specific ones to prioritize for non-wires solution consideration in its Distribution Investment Deferral Framework.[83] The Framework details the screening process investor-owned utilities must follow to develop annual Distribution Deferral Opportunity Reports that identify potential non-wires solution projects. As part of a technical screening, investments in certain project types are excluded from non-wires solution consideration, such as investments for non-capacity related reliability like automation, fault detection, and sectionalizing equipment. Besides a few categories not applicable for NWS, California rules generally consider distribution capacity, voltage/VAR support, reliability, and resilience services as best suited for NWS.

Considerations

The range of services that NWS can provide has not yet been fully explored. To date, most projects have addressed distribution or generation capacity constraints. Nonetheless, as collective experience with NWS grows and more pilots demonstrate their ability to effectively provide a wider range of grid services, NWS may be considered in a growing number of projects. New York and California both explicitly note that additional opportunities for NWS may exist and warrant further investigation. New York cites specific policy and structural changes needed to enable wider applicability of NWS for investment categories like power quality and conservation voltage reduction.[84] California similarly highlights resilience as an area in which NWS can play a larger role if interconnection, protection, communication, and visibility considerations are addressed.

4. Asset Condition

Specific investments can be excluded from non-wires solution consideration, ideally as part of a broader screening category

The same rationale for using a project type screening category is also relevant for using an asset condition screening category. Essentially, a utility might want to exclude certain investment types from analysis of NWS for safety or reliability reasons. Instead of reviewing and determining non-wires solution suitability for all potential investment categories, it might choose to screen for a specific category like asset condition so that any investment to address an asset condition need is excluded from non-wires solution consideration. Since the function of this category is aligned with the broader project type screening category though, it can be consolidated as a subset of the latter. For example, New York explicitly considers asset condition as part of its project type screening category.

Developing specific criteria

Rhode Island and Liberty Utilities have included an asset condition category in their screening criteria. Unlike New York, California, and Vermont, they don't have a separate project type screening category, so asset condition is the only investment type that is explicitly excluded for non-wires solution consideration. Asset condition investments are defined as planned repairs, replacements, or enhancements of existing infrastructure to ensure safe and reliable service. Ostensibly, this asset condition category was emphasized because there was an expectation that such investments would not be conducive to NWS, but that other investment types would. This approach might help encourage other non-wires solution projects, but is also likely too narrow and overly prescriptive since, as New York utilities discuss in their Supplemental Distributed System Implementation Plan, investments to repair or replace equipment may have components that could be suitable for NWS.[85]

Considerations

This category can effectively be combined with determinations of non-wires solution suitability for a wider breadth of project types. In practice, applying this category has proved problematic in Rhode Island, where it has been used less as a guideline and more as a definitive rule. For instance, the majority of projects proposed in National Grid's System Reliability Procurement Reports have been excluded from non-wires solution analysis based on the fact that most investments are somehow related to asset condition since Rhode Island's distribution system was largely developed in the 1920s.[86]

5. Project Size

Initial procurements can screen for non-wires solution opportunities that are below a certain size threshold to limit potential downsides of non-performance

Project size thresholds can be used as a precaution to provide utilities with the assurance that any non-wires solution project failure would be manageable. By limiting non-wires solution consideration to needs where less than a prescribed amount of peak load would be addressed, the utility would know that even a worst-case non-wires solution non-performance event could not trigger extensive outages. Although this screening category has been used in several jurisdictions, it's likely to decline in importance as large non-wires solution projects are piloted and their performance validated. Although it might serve a purpose for early stages of non-wires solution procurement, it is likely a screening category that will be unnecessary and potentially counterproductive in a more mature non-wires solution market environment.

Developing specific criteria

Utilities can try to limit initial NWS to relatively small needs to mitigate the risk of potential failures. Smaller non-wires solution projects also might make it easier for utilities to develop operational contingencies as risk management plans for non-wires solution non-performance. At the distribution level, both Rhode Island and Liberty Utilities of New Hampshire use project size as a screening criterion, only considering NWS for needs that relate to less than 20% of a given area's load. Vermont similarly uses 25% as its criterion for transmission projects, but it does not include a project size screen for the distribution level. It is unclear precisely how these thresholds were developed, and regulators should require analytical rigor before applying such criteria in the future.

Considerations

This criterion should provide utilities with the necessary assurance to get more comfortable with NWS. It should not preclude larger non-wires solution projects if they can prove sound risk mitigation strategies, and it should not indicate to the market that NWS will perpetually only address small needs. Ultimately this guideline should be a stepping-stone to larger procurements, once more performance data has been captured from implemented NWS.

2. COMPETITIVE SOLICITATION PROCESSES

Once a decision has been made to pursue NWS through a competitive solicitation, the utility should design the RFP to maximize the number of technically acceptable, cost-effective bids. For decades, utility procurement departments have run solicitation processes for traditional assets, but NWS solicitations require new and different considerations. To scale this market, it is important that solicitations are drafted with appropriate specificity, flexibility, and transparency.

Considerations for Crafting a High-Impact RFP

Prior to drafting an RFP, there are several high-level questions that the issuer should consider in order to determine the appropriate solicitation scope and quantity of information to be included.

FIGURE 11
CONSIDERATIONS FOR CRAFTING A HIGH-IMPACT RFP

Have existing DERs and programs been identified within the geographic area that could be used in an NWS?	Assess existing programs and DER penetration. Understand how existing DERs or customer programs could be leveraged in a solicitation or instead of issuing a solicitation.
Has bundling multiple identified needs into one RFP been considered, to enable a broader set of solutions and leverage economies of scale?	NWS projects may be bundled such that they enable potential solutions that need greater economies of scale to participate, such as software solutions. Bundling may reduce transaction costs, though could increase complexity and risk associated with execution. If the solution requires customer acquisition, bundling can also lead to efficiency gains in marketing.
Have developers been engaged to better understand the unique capabilities of their technologies, the feasibility of meeting the given need with an NWS cost-effectively, and data needs for developing an effective solution?	Consider an RFI, or additional stakeholder engagement before issuing an RFP to better gauge market interest and gather data necessary to issue a solicitation. Understanding the state of the market can help ensure that a solicitation will receive competitive bids.
Have stakeholders been engaged to understand potential community assets that can be leveraged through an NWS, and the community's concerns and needs?	Consider additional stakeholder engagement. This process can help to identify customers and assets that can be utilized to lower project costs and understand how a project can deliver value to customers. Community support and collaboration can result in stronger, more durable projects, and improve the probability of regulatory approval.
Are the costs of the traditional solution known, and is there an established threshold below which ideal solutions will bid?	Understand the costs of the traditional solution, and determine how that number will be used in evaluating bids.
Are there already prequalified vendors bidding into the solicitation?	Consider a vendor prequalification process to expedite review of bids and improve confidence that a set of bids will be received from qualified vendors.
Can the bid evaluation methodology be explained clearly to respondents?	Consider testing evaluation methodologies with bidders prior to RFP release to ensure clarity. Developers should be able to calculate how the utility will value their solution. Educational webinars or in-person workshops could be utilized to familiarize evaluation criteria with bidders.
Have communications protocols between the NWS and grid operators been developed and socialized with developers?	It is critical for developers to understand how grid operators intend to dispatch and call upon resources, and determine if their proposed solution is compatible with planned operation. RFPs should also lay out cybersecurity requirements. It can expedite interconnection and project commissioning to clearly delineate communication and cybersecurity requirements in the RFP.

RFP Components

The following are more specific considerations for crafting key sections of an RFP, including data requirements and insights on how a non-wires solution RFP might differ from an RFP for a traditional solicitation.

Needs-based problem description

A needs-based problem description with ample—and specific—data is necessary to provide respondents with a sufficient level of information to develop bids that are responsive to the issue the utility is seeking to address.

Technology providers likely require the following minimum level of information in a utility's non-wires solution needs description:

- **Type of need:** Different system needs (e.g., load relief, voltage support) require distinct technologies and/or approaches. Providing clarity around the need in an RFP encourages responses that include least-cost, best-fit technologies.
- **Need characterization:** Including the expected magnitude, frequency, and duration of the need, and predicted changes in the need with season and time can allow developers to perform technology-specific analysis to assess technical feasibility prior to submitting a formal bid, reducing unnecessary work during evaluation.
- **Projected online date:** The forecasted online date dictates the project timeline for developers. The online date should be realistically determined, so that it does not preclude developers with certain types of technology from bidding. If applicable, the solicitation should also include commitments on behalf of the issuer to support its desired timelines, such as streamlined interconnection and permitting.
- **Grid topology of the affected area:** Developers should be able to understand the system in which their technology will be deployed, including existing equipment condition and age, to develop solutions that interface seamlessly with existing grid assets and maintain reliability. National Grid and the Joint Utilities in New York provide **public maps** containing pertinent grid topology and feeder-level load information.
- **Geographic and customer demographic data:** Geographic data, such as GIS maps, can help developers to determine where their proposed solutions will be sited. Including the demographics of the geographic area of interest, such as breakdowns by customer class and aggregated load profiles, enables developers to propose realistic customer-sited solutions. Any customer demographic data released should also comply with customer data privacy restrictions. In its non-wires solution solicitation for load relief at Columbus Circle, ConEdison provides a **breakdown** of count, average and peak demand, and consumption for customers of various types.
- **8,760-hour load profiles:** Equipping developers with granular, hourly, or sub-hourly load data of the affected circuits enable them to calculate more accurately the reliability and availability of proposed solutions. Several RFPs include typical peak day hourly **load profiles**, though few have included full 8,760-hour load profiles as an attachment.
- **Hosting capacity data:** Many proposed non-wires solution projects include the addition of DERs (including solar and storage) that, at certain times, deliver power back to the grid. It is therefore important to know the ability of the target substation or circuit to "host" more DERs without compromising reliability, power quality, or safety, or requiring significant additional upgrades.[87] Hosting capacity map examples are provided from utilities in **Minnesota**, **Colorado**, **Hawaii**, **the District of Columbia**, **New York**, and **California**.
- **Overview of existing tariffs and programs:** Existing tariffs and programs and their current levels of participation in the target geographic area help developers identify areas of potential synergy. National Grid's **Old Forge RFP** includes data on existing program participation and information on distributed generation applications in the area of interest.

- **Plan for compensation:** The RFP should outline how the utility proposes to compensate the non-wires solution project (i.e., fixed or variable payments) and for how long (length of contract), or indicate if the utility is open to other payment option proposals. Specificity around compensation terms is a key driver of the developer's response, as well as determining the type of financing it will be able to secure.

Although it does not include all of the information recommended on this list, an illustrative example of system data to be included in NWA solicitations by the Joint Utilities in New York is presented below.[88]

FIGURE 12

NEW YORK JOINT UTILITIES SUPPLEMENTAL DSIP EXAMPLES OF SYSTEM DATA ELEMENTS TO BE INCLUDED IN RFP

TYPE OF SYSTEM DATA	ILLUSTRATIVE EXAMPLE
Size of the need	1 MW
Seasonality	June–August
Temporal profile of need	Between the hours of 1 and 4 p.m., for no more than three consecutive days
Duration of deferral	Five years
Geographical characterization of need area	A map showing the approximate boundaries of the need area, perhaps labeled with zip code information
Customer characterization of need area	Approximately 2,000 customers, split 80 percent residential and 20 percent commercial and industrial

Performance-based solution description

A performance-based solution description details the desired attributes and functions of a non-wires solution, while remaining agnostic with respect to the type of technology that should be employed. Specificity in this description is vital to ensure that proposed solutions will perform in a way that effectively meet the target need. Performance-based solutions descriptions should include the following considerations for NWS:

- **Dispatch details:** Though not all developers will need this data, providers of active solutions (e.g., those that need to be dispatched) should be provided with a general understanding of how often resources will be called upon and how and when signals will be sent, as well as expectations around response time. Utilities may not want to divulge specific protocols for security purposes, but enough detail should be provided to ensure that proposed solutions will be interoperable with existing control systems. Additionally, developers should be pointed toward cybersecurity protocols or requirements that may be applicable to NWS.
- **Technology readiness criteria:** While ensuring that reliability criteria are met, non-wires solution descriptions should not unnecessarily restrict solutions that utilize new technology, and utilities may have to adjust expectations from traditional solicitations around qualitative requirements for technology "readiness." For example, utilities may require that technology used for NWS have been demonstrated in an in-situ pilot, rather than deployed on a large number of existing projects. Projects with longer lead times or lower reliability thresholds should consider a broader range of technologies. Pilot projects and research and development programs should be used to test the reliability of new technologies, provide developers feedback to improve the technology readiness of their solutions, and create a pipeline of technologies ready for deployment in NWS.
- **Reliability, maintainability, availability:** Reliability is defined as the probability of normal performance under standard operating conditions over a period of time. Reliability is often calculated as mean time between failures, or the total operational time divided by the number of failures within that time frame. Maintainability refers to the amount of time between failure and normal operation. Availability is a combination of those two metrics, representing the ratio of total uptime to total downtime, and is typically represented as a percentage. To the extent that a certain degree of availability is necessary to meet the specified need, it should be detailed in the solution description. Alternatively, bidders should be asked to provide their guaranteed or minimum levels of availability for their proposed technical solutions.
- **Standard operating conditions:** An RFP should describe the ambient conditions under which the solution will be expected to operate, such as temperature ranges or applicable noise restrictions. Specifying these criteria from the outset can help avoid costly delays during development. Likewise, technology providers should be asked to give the normal operating conditions for their products.

National Grid contains a summary table at the front of its **solicitation** for NWS at Van Dyke, Buffalo 53, and Golah-Avon, which includes both succinct problem statements and solutions requirements including dispatch criteria and availability.

Instructions to respondents

If bidders are provided with ample data in an RFP needs and solutions description, they should be asked to provide responses with a comparable level of detail that describe how their proposed solution will adequately address the utility's desired outcome. Developers should strive to include sufficient information for utilities to have confidence in the solution's technical feasibility, without being so overwhelmingly technical that they inhibit easy comparison across bids. Non-wires solution solicitations should consider asking for all bidders to provide the following information:

- **Background and qualifications:** If there is no prequalification process, non-wires solution providers should describe their relevant experience, including delivery of similar projects. Unlike traditional infrastructure providers with decades of experience, many non-wires solution players will have more limited experience, which should not preclude their participation; utilities may need to adjust their traditional qualification requirements to address this issue.
- **Solution description:** If probabilistic load forecasts are provided to developers, a utility should ask developers to describe how their solution will respond under varying conditions. Likewise, if hourly load forecasts are provided, solutions can be expected to demonstrate hourly load reductions using their technology. Developers should also be asked to specify any additional values or services that the project could provide, and any additional needs they think may also be met by their proposal.
- **Cost description:** Consider providing a uniform way for developers to provide a breakdown of their project's cost, whether through a template, key metrics, or a defined process. Ensuring that solution costs are provided in standard, comparable format could potentially save the utility many hours of recalculation during bid evaluation.
- **Measurement and verification plan:** Because NWS are still emergent, it is even more important to collect data, and for developers to share their data with the utility. Accurate measurement and verification data will help improve scoping for future projects, and sharing non-proprietary results can help the whole market move forward.
- **Additional data needs for project implementation:** Requesting that developers clarify the data required for their project implementation allows utilities to start identifying and organizing information to expedite project development. Additionally, if the same data needs are identified by several developers, utilities might consider including it in future solicitations. Data in terms of the performance output is also important for utilities to more effectively manage the grid.
- **Description of non-energy benefits and impacts:** Developers should be encouraged to include descriptions of how their proposals provide non-energy benefits and community and environmental impacts in their responses. NWS have the potential to drive progress toward carbon reduction, economic development, and other policy goals. These benefits should be included in utility evaluation frameworks (see the Proposal Evaluation section), and the methodologies used to quantify the benefits made transparent so that developers can tailor solutions to optimize them.

Several utilities have provided spreadsheet tools for respondents to highlight key comparable information about their bids.

Solicitation timeline

In an RFP, utilities should lay out realistic timelines for the solicitation process, project development, and implementation:

- **The solicitation process** timeline should include sufficient time for developers—including those with limited resources—to prepare and submit responses. Additionally, the RFP should highlight opportunities for prospective bidders to ask questions. Utilities should lay out a reasonable timeline for evaluation of bids and make clear when they intend to select bidders.
- **Project development and implementation** timelines should reflect the timing of the need to be met and allow enough lead time for different technologies to compete.

Evaluation criteria

There is a need for utilities to include a clear description of how bids will be evaluated within the RFP. This description should include both criteria for technical feasibility and benefit-cost analysis. Developers should be able to understand the relative importance of the different assessments that will be used to evaluate bids.

Recommendations for structuring criteria for evaluation are provided in the Proposal Evaluation section below.

RFP examples

The following links to RFPs for some of the projects discussed in this playbook are provided for reference:

- **Joint Utilities of New York:** Centralized portal with links to all non-wires solution opportunities for each of the New York utilities
- **GridSolar:** Boothbay, Maine RFP (2013)
- **Southern California Edison:** Local Capacity Requirements RFO (2013)
- **Pacific Gas & Electric:** Distribution Resources Plan RFO for Demo C and Demo B (2017)
- **Bonneville Power Authority:** Non-Wires Measures for South of Allston RFO (2016)

3. PROPOSAL EVALUATION

NWS represent a new type of procurement to solve critical grid needs. As such, they require a well-considered evaluation methodology because they span traditional lines of supply, demand, and infrastructure options. Evaluation must consider both the technical ability of a non-wires solution to meet the grid need and its cost-effectiveness in doing so. While numerous studies have sought to quantify the technical services that DERs can provide the grid and have weighed the relative merits of different cost-effectiveness tests, the NWS context requires unique considerations. To effectively compare varying non-wires solution approaches and appropriately value the range of benefits that they provide, holistic and NWS-specific methodologies for technical and benefit-cost analyses can be adopted. Transparency into these methodologies should also be provided to the market to facilitate non-wires solution bid development.

Utilities should only deploy a non-wires solution once they have verified that it is technically capable of solving the relevant grid need

In California, technical screening is an upfront process that happens before going to market to seek solutions. DERs are considered to provide four grid services (distribution capacity, voltage support, reliability, and resiliency) and needs are only considered for NWS if they relate to those services. In other jurisdictions without initial technical screens, the feasibility assessment occurs once proposals are received. Evaluation may be different depending on who integrates the solution. If the utility is serving as the solution integrator, it might have to develop and evaluate aggregated portfolios of proposals. Alternatively, if a third party is the solution integrator, the utility might evaluate complete solutions that have been integrated into portfolio proposals. In either case, since NWS are required to replace traditional infrastructure that supports system operations, it is paramount that the non-wires solution be technically equivalent to ensure reliability. For example, for a non-wires solution to defer the planned upgrade of a transformer that was expected to exceed its peak loading limits, the project proposal would have to demonstrate that it could be deployed in time and could effectively reduce loading to remain within the equipment's designated limits.

To ensure that non-wires solution proposals are evaluated fairly and effectively, technical evaluation of bids should be based on detailed modeling of both passive load impacts (e.g., from energy efficiency or distributed PV) and dynamic or active controllable responses from dispatchable technologies (e.g., demand flexibility and energy storage technologies). Leading non-wires solution examples suggest that these evaluation tools can include:

- **Hourly modeling:** Tools should aggregate year-long hourly profiles (e.g., load reductions, dispatch outputs) from candidate proposals to determine if the expected response across a portfolio of technologies is adequate to meet the system need (e.g., peak hour loading, contingency scenario). Sub-hourly modeling, if available, will provide an even more accurate representation of non-wires solution benefits.
- **Response time:** For active technologies (like

batteries and demand flexibility), response time and/or automatic scheduling capabilities will be a determining factor to ensure that these resources can be secured far enough in advance to address system needs as well as any emergency services that the utility values.

- **System integration:** Technology-level review of the candidate solutions and their respective hardware/software specifications assures utilities that they can effectively integrate control and/or measurement and verification (M&V) needs with their existing systems.
- **Location-specific data:** Specificity in the scope of a proposed solution, including its relationship to hosting capacity and targeted customers or technologies, would help a utility determine if the proposal would solve the need and can help it compare different proposals against each other.

Evaluation of technical feasibility should also take into account several categories of risks that may arise as part of portfolio deployment, operations, and payment settlement. Utilities can quantify these risks for each solution component, develop corresponding operational contingency plans, and integrate the costs of those plans into the portfolio evaluation. Risk evaluation can be done at both the project-specific and portfolio-wide level (see the **NWS Contracting Considerations section** on page 70 for strategies to effectively allocate risk via contracting). Liberty Utilities explicitly considers risks by ranking each non-wires solution against a set of prescribed risks in their evaluation process.[89] Rhode Island also references consideration of a suite of risks in the prudency component of their evaluation.[90] Building on these best practices, evaluation approaches and modeling tools should take into account specific risks corresponding to different DER technologies and the portfolio as a whole, illustrated in the following table:

FIGURE 13

TECHNICAL RISKS AND MITIGATION STRATEGIES BY TECHNOLOGY

	TECHNOLOGY APPLICABILITY				
TECHNICAL FEASIBILITY RISK	ENERGY EFFICIENCY (EE)	DEMAND RESPONSE (DR)	DISTRIBUTED GENERATION (DG)	BATTERY ENERGY STORAGE (BES)	MITIGATION STRATEGIES
Operational-level performance uncertainty (e.g., outages, software malfunctions, connectivity issues, resource variability)	✔	✔	✔	✔	Operational performance risk is common to all DERs that function as a non-wires solution. They are best addressed by using probabilistic modeling to determine the expected range of availability during constraining events. Common-mode failures across DERs (e.g., connectivity issues that would limit active control across the portfolio) should also be identified, their impacts evaluated, and addressed if needed (e.g., through backup communications channels or portfolio diversification).
Planning-level performance uncertainty	✔	✔	✔	✔	Planning-level risks associated with DER deployment apply to all technologies, and manifest as uncertainty around whether the technology portfolio can be deployed fast enough to meet the project-level need. These risks can be mitigated by deploying technologies in stages and measuring progress during deployment to identify issues and enable course-correction.

Table is continued on the next page

FIGURE 13 (CONTINUED)

	TECHNOLOGY APPLICABILITY				
TECHNICAL FEASIBILITY RISK	ENERGY EFFICIENCY (EE)	DEMAND RESPONSE (DR)	DISTRIBUTED GENERATION (DG)	BATTERY ENERGY STORAGE (BES)	MITIGATION STRATEGIES
Causal risks related to improvements over baseline	✓	✓			Causal risks apply to demand-side management technologies and are driven by uncertainty around whether the technologies are directly responsible for load reductions. Use of advanced, statistics-based M&V strategies can more accurately measure the contributions of EE and DR, better assess whether the portfolio is meeting its targets, and identify potential intervention approaches if it is not.
Non-participation		✓	✓	✓	Non-participation risks pertain to actively controlled DER technologies (e.g., DR, smart inverters on distributed PV and batteries) that don't respond during critical events. This risk can be partially mitigated by performance guarantees backed by financial penalties and security deposits from counterparties that incentivize participation. Risks can also be more certainly mitigated by including contractually mandated direct control elements in technology deployments or managed by modeling typical non-participation rates as part of the statistical modeling of the expected response (see above).

Existing cost-effectiveness tests should be tailored to appropriately compare NWS proposals against each other

There is a range of well-established cost-effectiveness tests designed to evaluate the impact of DERs on distribution grids. Five tests in particular have been commonly leveraged to conduct benefit-cost analysis (BCA) for utility initiatives: societal cost test, total resource cost test, utility cost test, ratepayer impact measure, and participant cost test. Although these tests overlap in a number of ways, each has its distinct perspective and approach, along with its relative strengths and weaknesses.[91] Application of any of these tests to evaluate a non-wires solution requires adaptations to ensure the range of local benefits that NWS can provide are considered. For example, whereas the traditional calculation methodologies focus on system-level energy and capacity-value inputs, non-wires solution evaluation should account for distribution-level components of avoidable costs and potential benefits.

Other important considerations for a non-wires solution evaluation framework include:

- **Evaluate all non-traditional distribution system enhancement categories with a single framework** so that non-wires solution proposals based on different strategies (supply, demand, or infrastructure) and technologies can be effectively compared.
  - A stated goal of Rhode Island's BCA framework was for it to be able to evaluate costs and benefits across any and all programs or policies to enable direct comparisons of the relative merits of various investment options.[92]
- **Cost-effectiveness tools should be able to optimize portfolios of solutions** instead of assessing individual measures. This approach borrows from integrated resource planning practices that optimize different sets of possible supply solution combinations. Optimization of portfolios with a multitude of variables is complex and automation through software tools will facilitate the transition from current manual approaches to more streamlined optimization practices.
  - New York's BCA framework was explicitly designed to assess portfolios, rather than individual measures or investments, to allow the consideration of potential synergies and economies between resources or measures as they are aggregated to satisfy a given need.[93]
- **Use state-, utility-, and project-specific data** so that model inputs are as granular as possible, with system-wide energy, transmission, and distribution avoided costs broken down to assign locational values wherever possible to more accurately reflect the local nature of non-wires solution costs and benefits.
  - California's Locational Net Benefits Analysis tools represent an effort to identify and quantify location-specific avoided costs and benefits associated with deferral or avoidance of distribution system expenditures.[94] Central Hudson Gas & Electric in New York also worked with Nexant to conduct a detailed study to determine location-specific avoided transmission and distribution costs.[95]
- **Develop calculations for hard-to-quantify benefits** so that additional sources of non-wires solution value, such as environmental, social, and economic development benefits are accounted for in a transparent way that developers can use to optimize their bids.
  - The New York BCA requires that externalities (defined as effects of one economic agent on another that are not accounted for in normal market behavior) are quantified when possible, and at least considered qualitatively when not. For example, ConEdison's BCA includes prescriptive calculation methodologies for external benefits including net avoided CO_2, SO_2, and NO_x, and notes that avoided land, water, and net non-energy benefits related to utility or grid operations would be assessed qualitatively by the traditional cost-effectiveness tests like the societal cost test that are embedded as part of the overall BCA evaluation process.[96]

- **Consider incrementality to mitigate incentive double-counting** and to ensure that NWS projects are deployed as a result of the non-wires solution sourcing mechanism and not in connection with other programs. Concerns could otherwise arise regarding the solution benefits being included in both the non-wires solution evaluation and the cost-effectiveness justification for other programs like energy efficiency or net energy metering.
  - In their Supplemental Distributed System Implementation Plan, New York utilities note that certain non-wires solution opportunities may overlap with existing tariff programs. To address this, they suggest that rules need to be clarified delineating attribution between NWS and other related programs and that compensation needs to be coordinated across programs to account for the potential for a single resource to participate in multiple programs.[97] California also addressed this issue through a working group focused on issues of incrementality as part of its Competitive Solicitation Framework proceedings.[98]
- **Include option value in evaluation** by using probabilistic approaches to reflect uncertainty in underlying planning variables and capture the planning flexibility benefits that NWS can provide. In lieu of established precedents, this aspect of best practice for evaluation requires additional attention to develop appropriate calculation methodologies.
  - Utility planners identify and prioritize future system needs based on projections of inherently local and interdependent factors like load, price, and weather. Instead of using average projections, planning can employ statistical analysis of the probabilities associated with a range of projections to help fully capture the avoided cost benefits that non-wires solution projects can provide.[99]
- **Consider conducting independent technical analysis to diligence non-wires solution opportunities** including the quantification of their costs and benefits.
  - California includes in its evaluation framework the role of an independent professional engineer to conduct technical reviews of the assumptions and results of the annual planning process and the application of deferral screening criteria.[100]

Examples of evaluation processes that include these best practices can be drawn from jurisdictions with the most non-wires solution experience

New York has established a robust benefit-cost analysis methodology that, despite being complex, manages to encompass the key best practices for non-wires solution evaluation.[101] The state's Public Service Commission developed a BCA framework that the utilities used as the basis for producing their respective BCA handbooks. These BCA handbooks are widely used to evaluate all investments in distributed system platform capabilities, procurement of DERs via competitive selection and tariffs, and energy efficiency programs. The handbooks include extensive documentation on the benefits and costs that are evaluated, defines calculation methodologies for each category, and includes relevant local data where possible. Portfolio optimization is central to this BCA framework, and externalities (like environmental and economic benefits) are required to be considered. Option value is also addressed through mandatory sensitivity analysis on key assumptions.

Rhode Island has developed its own benefit-cost framework through extensive stakeholder engagement.[102] The state adapted the total resource cost test to more fully reflect its energy, environmental, and social policy objectives. The resulting evaluation framework contains a broad set of factors, including consideration of environmental and social externalities, and details options for benefit and cost quantification methodologies alongside the relevant data needed for each calculation. The framework encourages the inclusion of location-specific data and option value considerations in recognition of the fact that costs and benefit values will vary by time, location, electrical product, technology, and customer. It also states that as the regulator and market participants gain experience with each cost and benefit category and driver, standard practices will evolve and become more sophisticated.

Utility evaluation process transparency can add value to the market

If utilities were able to share the models and processes they use to evaluate non-wires solution proposals, developers could more accurately anticipate the competitiveness of their bids and optimize them to maximize value to the utility. Developers argue that without clear evaluation criteria, their ability to tailor solutions that address utility needs and provide relevant benefits is inhibited. On the other hand, utilities are concerned about releasing information they consider their intellectual property, such as the complex evaluation models they have dedicated considerable resources to developing. Utilities also develop operational contingencies to accommodate identified risks, and it may be difficult to publicly release these strategies. Further, if the utility is going to be the integrator, a developer might not even be able to use the utility's evaluation model to determine the competitiveness of their bid, since the utility would be aggregating it with others to evaluate on a portfolio basis.

Despite the tension evident in providing full transparency into evaluation details, it is reasonable to conclude that some degree of insight into utility evaluation procedures and methodologies would help improve bids and support effective market engagement.

4. NWS CONTRACTING CONSIDERATIONS

RMI is grateful to Peter Mostow, Scott Zimmermann, Grace Hsu, and Tim Cronin of the Energy Practice of Wilson Sonsini Goodrich & Rosati for helping us prepare this section.

Utilities have a long history of contracting for third-party services, and are able to draw on those precedents when negotiating terms with third-party owners of non-wires solution projects. To a large extent pro forma non-wires solution contracts can mirror existing utility documents, however there are four key areas—dispatchability, payment, performance, and construction—that require the most attention to effectively adapt standard contract clauses to the non-wires solution context. These adjustments relate to the fact that risk profiles for certain non-wires solution technologies differ from traditional grid infrastructure. Since the non-wires solution market is not yet mature, there is no broad agreement on how these risks should be allocated and the lack of consensus slows down the negotiation process between utilities and developers. For the non-wires solution market to scale more rapidly, market participants should coalesce around mutually agreeable contracting structures that recognize stakeholders' needs and the characteristics of DER technologies used in non-wires solution applications.

Contracts between non-wires solution integrators ("Integrators")—typically but not always a utility—and NWS developers ("Developers") can take many forms and have many names. In general, however, each such contract contemplates the Developer agreeing to deploy a technology or method (the "Resource") to achieve a net reduction in the electricity demand in a designated area of the grid. This net reduction may be achieved by generating or discharging electricity within the target area, either by causing a customer account ("Account") in that area to shift consumption from one period in the day to another, or by causing an Account to eliminate certain consumption altogether.

Another distinction among NWS contracts is the level of control the Integrator has in reducing electricity demand. One type of non-wires solution contract allows an Integrator to cause the reduction in demand to occur at a time of the Integrator's choosing. This type of "dispatchable" non-wires solution contract could, for example: a) allow an Integrator to call on a Developer to discharge a battery, b) cause Accounts to turn off, or reduce consumption of building equipment, appliances, or lighting, or c) initiate generation from a dispatchable generator (e.g., fuel cell). Another type of non-wires solution contract contemplates a reduction in demand that is fixed and non-responsive in nature. This could involve: a) a Developer's permanent shifting of certain recurring consumption by an Account from one period in the day to another on a long-term basis, b) the Developer's installation of more efficient lighting or HVAC equipment at an Account's building, or c) the Developer's installation of non-dispatchable distributed generation (e.g., solar not paired with storage) at an Account's facility.

Developers are working with a broad array of technologies to meet the functional requirements of differing NWS, and many specific types of NWS contracts can be fulfilled by more than one technology. Therefore, in conducting a solicitation for NWS resources, an Integrator will want to keep its request for proposals and its non-wires solution pro forma contract as technology-neutral and standardized as possible, keeping in mind the array of technologies available to Developers. Accordingly, this section does not provide an exhaustive list of technology-specific provisions that would appear in each possible non-wires solution contract type; rather, we have focused on the most critical terms in any non-wires solution contract, with an eye toward highlighting those that differ from more traditional standard contracts between a utility and Developer (e.g., power purchase agreement for solar, or energy savings performance contracts for energy efficiency). These key contract provisions are described in detail below, with specific consideration given to their application in the context of some of the more commonly deployed non-wires solution technologies. Important to note is that often an Integrator will seek or receive bids for multiple technologies in a non-wires solution solicitation, and sometimes multiple technologies are contemplated under one non-wires solution contract. For example, energy efficiency contracts might involve the installation of new lighting and HVAC equipment (with stronger performance efficiency as compared to existing equipment) as well as an overlay of smart controls and sensors to maximize operational efficiency and allow for dispatchability.

Non-Wires Solution Contract Types

Developing more standardization around non-wires solution contract terms is an important way to accelerate the NWS market. Contract norms create a common set of expectations for market participants, which simplifies negotiations and the procurement process more generally. Illustrative of the current lack of standardization is the number of different contract types in the NWS market, including:

- Resource Purchase Agreement
- Purchase and Sale Agreement
- Power Purchase Agreement
- Capacity Attribute Purchase Agreement
- Energy Storage Agreement
- Demand Response Agreement
- Demand Response Energy Storage Agreement
- Energy Efficiency Agreement
- Permanent Load Shift Agreement

While this contract nomenclature often describes the purpose of each given contract, the manifold contract names obscure the fact that that the names themselves do not dictate any specific terms or parameters for the relevant Resource. Much more important than the contract name is the way in which risk is allocated among the parties.

Key Terms in NWS Contracts

The most central provisions in a non-wires solution contract will look similar to many other utility contracts (e.g., milestone schedule, payment formulas, performance guarantees). Still, they of course must account for the unique nature of the Resource being procured—both in terms of its function and the technology being utilized. The table on the following page discusses the provisions that require the most modifications from typical utility contracts to accommodate the non-wires solution context.[i] Additionally, it identifies certain market solutions to the risk-balancing exercise between Integrators and Developers that can be adopted across technologies, as well as some technology-specific considerations.

FIGURE 14
KEY TERMS IN NWS CONTRACTS

ISSUE	DISPATCHABILITY	
TERMS INCREASING RISK ON INTEGRATOR	• No control over dispatch of Resource or limited control (e.g., fewer days on which dispatch is allowed, fewer allowed dispatches per day or per month, shorter allowed dispatch duration).	• Limited visibility into, and requirements for, participating Accounts. • Unrestricted Developer rights to utilize the Resource on its own behalf (or on behalf of third parties).
TERMS INCREASING RISK ON DEVELOPER	• High level of Integrator control over dispatch timing, frequency, and duration. • Greater Integrator visibility into, and requirements for, participating Accounts.	• No Developer rights to utilize the Resource discretionarily on its own behalf (or on behalf of third parties).
MARKET SOLUTIONS FOR BALANCING RISK	• The Integrator's level of control over dispatch depends on the technology and on the Integrator's needs. The Integrator will need to pay for greater levels of control over dispatch because such priority is valuable (in that it may require the Developer to forgo other revenue streams) and because it may require additional technologies (i.e., storage, sensors). • Integrator's level of visibility into, and requirements for, participating Accounts can be limited to ensuring that the Resource is addressing the Integrator's need (e.g., location of accounts, size of estimated Resource based on Accounts).	• Developers often will seek to reserve the right to discretionarily utilize the Resources on its own behalf or on behalf of others in order to obtain additional revenue streams (i.e., from behind-the-meter-customers and/or from markets that may not be in existence at the time the non-wires solution contract is entered into such as future energy, capacity, or ancillary services markets). Integrators may grant these Developer utilization rights (because doing so enhances project financeability) but must ensure that such rights do not undermine the Integrator's primary objective in entering into the non-wires solution contract and also do not compromise the operational integrity of the Resource (e.g., by increasing wear on equipment).

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[i] Many other provisions—for example those concerning agreement effectiveness, contract regulatory approval as a condition precedent, Developer governmental approvals, disputes, indemnification, limitations of liability, standard representations and warranties, etc.—do not need to be adapted nearly to the same extent and, in many cases, can simply be copied from standard utility contract forms.

IMPLEMENTATION GUIDELINES

FIGURE 14 (CONTINUED)

ISSUE	DISPATCHABILITY	
TECHNOLOGY-SPECIFIC CONSIDERATIONS	**Storage** • A non-wires solution contract involving energy storage often takes the form of (1) a permanent load shift agreement, by which the Developer agrees to shift an Account's consumption from one period in the day to another period in the day over a period of years, or (2) a demand response resource purchase agreement or energy storage agreement pursuant to which the Integrator is typically granted the right to call for dispatches of the resource within agreed upon parameters.	• Integrators can contract with a Developer for priority use over the storage unit (as compared to utilization on the Developer's own behalf or on behalf of a behind-the-meter customer). **Distributed Generation** • In the case of dispatchable distributed generation, the Integrator might require that the Developer dispatch specifically (or exercise all reasonable efforts to dispatch) during grid events declared by the Integrator.
ISSUE	**PAYMENT**	
TERMS INCREASING RISK ON INTEGRATOR	• Fixed monthly payments based on (1) an assumed or forecasted level of reductions that the Resource is expected to achieve or (2) the capacity value of the Resource.	
TERMS INCREASING RISK ON DEVELOPER	• Variable monthly payments based on the actual reductions the Resource achieves.	
MARKET SOLUTIONS FOR BALANCING RISK	• It is typical to have variable monthly payments based on the Accounts' actual usage as compared to an assumed baseline amount that is calculated pursuant to an agreed upon formula. Payment formula may include incentives for strong reduction performance.	• Alternatively, if fixed monthly payments are used, Integrators can mitigate some of the risks involved with fixed payments by requiring Developers to provide performance guarantees, which are in turn backstopped by credit support (e.g., corporate guarantee, letter of credit, or reserve account), as discussed in greater detail below.

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FIGURE 14 (CONTINUED)

ISSUE	PAYMENT
TECHNOLOGY-SPECIFIC CONSIDERATIONS	**Energy Efficiency** • Energy efficiency projects can involve a wide variety of technologies, each of which invites specific considerations that need to be addressed. Lenders that finance energy efficiency projects typically prefer the certainty of fixed monthly payments over a performance-based payment structure and seek to avoid the risk associated with establishing and measuring performance against baseline energy consumption. Performance-based payments are also disfavored by Developers because they are not in full control over the ambient or load characteristics of a building given the role of the building's staff in operating and maintaining the building. • In the case of heavy and/or expensive building equipment upgrades (e.g., replacement of HVAC equipment, lighting, or appliances, as opposed to the mere installation of sensors and switches), an Integrator might pay the Developer for a significant portion of the expected savings upon the installation of the equipment, followed by payment for the remainder of the expected savings on a periodic basis thereafter after taking into account actual performance. **Storage** • For energy storage non-wires solution contracts, it is common to have a fixed payment component for installed capacity and a performance-based variable component based on actual dispatch. The separate payments for capacity and actual dispatch can be negotiated to provide sufficient comfort to financiers (i.e., to ensure adequate baseline revenues for project financing). **Distributed Generation** • NWS contracts for distributed generation will generally look more like a typical power purchase agreement than other NWS contracts, often with the Developer simply receiving a per kWh energy payment.

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FIGURE 14 (CONTINUED)

ISSUE	PERFORMANCE	
TERMS INCREASING RISK ON INTEGRATOR	• No performance guarantee from the Developer to the Integrator. • No contract termination right in the event of significant Resource underperformance. • Maintenance responsibilities belong to the Account customer as opposed to the Developer. • Limited rights to performance reports.	• No right to inspect the resource and/or audit the Developer's performance calculations and measurements. • In situations where the Resource involves multiple Accounts, the Integrator is given limited visibility into those Accounts and no rights regarding whether Accounts can be circulated in and out of the Resource.
TERMS INCREASING RISK ON DEVELOPER	• The Developer guarantees to the Integrator the performance of the Resource at negotiated levels, agrees to pay liquidated damages for performance shortfalls, and backs up the obligation with the Developer's balance sheet or credit support. • Abrupt termination right in the event of Resource underperformance. • Maintenance handled by the Developer. • Equipment warranty and spare parts inventory requirements.	• Comprehensive performance report requirements. • Broad Integrator inspection and audit rights. • In situations where the Resource involves multiple Accounts, the Developer must provide detailed information on each Account to the Integrator and is restricted in its ability to circulate Accounts in and out of the Resource.
MARKET SOLUTIONS FOR BALANCING RISK	• Performance guarantees are typical, with negotiated baselines, exceptions, and penalties. Liquidated damages should correspond to Integrator's actual costs incurred when the Resource underperforms (e.g., replacement capacity or energy). If the Developer entity that is party to the non-wires solution contract is not creditworthy, then its performance guarantee should be backed by an adequate form of credit support (e.g., parent guaranty, letter of credit, cash in escrow).	• Developers may negotiate flexibility in performance guarantees to render them less absolute. For example, performance metrics can be calculated on a rolling basis to avoid hair-trigger liquidated damages based on short-term performance. When a Resource is implemented across multiple Account sites, Developers can benefit from a "portfolio effect" to smooth out performance issues: over-performance at one Account site can counter an underperforming Account site elsewhere.

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FIGURE 14 (CONTINUED)

ISSUE	PERFORMANCE	
MARKET SOLUTIONS FOR BALANCING RISK (CONTINUED)	• The Integrator has a right to terminate the non-wires solution contract only in the event of consistent Resource underperformance (e.g., less than 80%–90% of estimated performance over the course of two years). • Maintenance obligations vary depending on technology. • Reporting requirements and inspection rights vary but typically grant the Integrator with an adequate method for confirming performance of the Resource and the Developer's invoices.	• In situations where the Resource involves multiple Accounts, often the Developer is allowed to freely circulate Accounts in and out of the Resource (subject to specified eligibility requirements). Typically, the Developer is obligated to at least provide the Integrator with a monthly list of participating Accounts.
TECHNOLOGY-SPECIFIC CONSIDERATIONS	**Energy Efficiency** • Energy efficiency NWS contracts might include a performance guarantee by the Developer in favor of the Integrator that promises the Resource will achieve minimum levels of energy savings. Similar to renewable energy power purchase agreements, these performance guarantees are set at some percentage of projected energy savings to be achieved by the Resource at the Accounts, forecasted based on technical assumptions regarding the Resource and the Accounts' historical energy usage. If these minimum levels of energy savings are not met, the Developer is typically obligated to pay liquidated damages as compensation for the underperformance. • The challenge with performance guarantees lies in the establishment of a baseline. The calculation of an energy efficiency project's performance will need to address, through carve-outs, specific circumstances over which the Developer has little or no control, including changes in building load profile, operations, occupancy, or the Account customer's default of its obligations. Developers often reserve the right to adjust the baseline if any of these exceptions occur.	• Routine maintenance on energy efficiency equipment is typically performed by the Account customer rather than by the Developer.* Equipment is located within a building and may be difficult for the Developer to access during normal hours without providing ample advance notice. It therefore can be serviced more efficiently by the Account customer. For these reasons, Developers tend to heavily negotiate the guaranteed turnaround time for any equipment repairs. • A spare parts inventory is not frequently required as equipment can be very expensive, susceptible to obsolescence, or readily available when needed (e.g., sensors, lighting, ballasts).

*The Developer can, however, perform remote diagnosis and troubleshooting of specialized control equipment.

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FIGURE 14 (CONTINUED)

ISSUE	PERFORMANCE	
TECHNOLOGY-SPECIFIC CONSIDERATIONS (CONTINUED)	**Energy Storage** • In the case of energy storage NWS contracts, performance guarantees can be structured both for variable payments (i.e., for energy dispatch) and fixed payments (i.e., for capacity). Contracts typically include a minimum level of threshold capacity that must be achieved; if the Developer fails to reach this level, the Integrator pays nothing at all for the relevant contract period. • NWS contracts for battery storage usually contemplate battery degradation by requiring a specified amount of capacity in year one of the non-wires solution contract and then accepting a degree of expected degradation thereafter. In addition to a performance guarantee, however, a battery degradation warranty provided by the manufacturer to the	Developer is often passed through to the Integrator. This warranty resembles a solar photovoltaic project degradation warranty in that it guarantees that degradation won't exceed a specified percentage per year. The Developer may also serve as the Integrator's agent for any warranty claims. • The Developer typically retains most maintenance obligations given the specialized nature of storage technology; although this can vary among different technology types, behind-the-meter Resources, and in-front-of-the-meter Resources. • Integrator NWS agreements are an important lynchpin for enabling third-party financing of battery storage projects, so Integrators frequently have leverage for negotiation.
ISSUE	**CONSTRUCTION**	
TERMS INCREASING RISK ON INTEGRATOR	• No milestone requirements for Developer's installation of relevant equipment.	• No independent engineer certification of construction completion and/or commercial operation.
TERMS INCREASING RISK ON DEVELOPER	• Strict milestone requirements for installation of equipment. Strict Integrator termination rights in lieu of "pay-for-delay" liquidated damages (which would inhibit the Integrator's right to contract termination). • Strict requirements for construction notice-to-proceed (NTP), with associated pre-NTP termination rights for the Integrator.	• Overly burdensome independent engineer certification requirements.

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FIGURE 14 (CONTINUED)

ISSUE	CONSTRUCTION	
MARKET SOLUTIONS FOR BALANCING RISK	• Construction and/or commercial operation requirements, as applicable, with liquidated damages in the event of a delay. The Developer should be allowed to "pay-for-delay" for a significant period of time as opposed to facing immediate termination in the event that construction or commercial operation is delayed. Liquidated damages should replicate the Integrator's costs in the event that the Resource is delayed (e.g., expected cost to replace capacity or energy). • If a non-wires solution contract requires regulatory approval, then, in the case of NWS technologies involving significant construction timelines, construction and commercial operation milestones should be pushed back in the event that the regulatory approval is unexpectedly delayed. Where a Resource requires significant equipment installations prior to operation, the Developer likely will not be	able to finance those installations until the regulatory approval is obtained. A delay in the Integrator obtaining that regulatory approval should therefore also allow for a corresponding delay in construction. Integrators and Developers should consider allowing for similar extension rights where a Resource requires significant Account recruitment operations prior to commercial operation because Developers can be hesitant to undergo that recruitment prior to obtaining regulatory approval of the non-wires solution contract (so as to avoid upsetting customers with long wait times before installations or operations actually commence). • Independent engineer certification requirements dependent on technology and non-wires solution function.
TECHNOLOGY-SPECIFIC CONSIDERATIONS	**Energy Storage** • Independent engineer certification requirements are typical for energy storage NWS contracts. For in-front-of-the-meter Resources, in-person inspection by an independent engineer is likely to be required. For behind-the-meter Resources, Developers prefer independent engineer sign-off on a representative design and specifications or to perform remote inspections based on observable data. Developers try to avoid the cost associated with a visit to each individual site particularly in the residential context or for smaller systems.	**Energy Efficiency** • In the case of energy efficiency NWS contracts involving smaller/lighter equipment (e.g., lighting, sensors), such equipment may be required to meet certain classifications (e.g., UL listings), but it is typically impractical from a cost perspective for it to be inspected and certified by an independent engineer. As with energy storage, representative designs may be approved by an independent engineer.

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FIGURE 14 (CONTINUED)

ISSUE	CHANGE IN LAW
CHANGE IN LAW	• NWS contracts often involve new technologies and new revenue streams within electric utility markets. Given the likelihood of regulators establishing additional rules for these technologies and revenue streams during the term of a non-wires solution contract, NWS contracts should take into account changes in law. Because the precise issues that regulators will address in the future and the approaches that they will take on those issues are difficult to predict, NWS contracts sometimes include general language indicating that the parties will cooperate and act in good faith to restore the initial relative economic benefits of the parties under the non-wires solution contract in the event of a change in law. • The possibility of future marketable attributes of the Resource is something that a non-wires solution contract should expressly contemplate (e.g., specific attributes tradeable in a subsequently developed market). This can be done by allocating to one party the right to market and sell future attributes, with the revenues and costs associated therewith either being allocated to the same party or shared between the parties.

CONCLUSION

CONCLUSION

The market for NWS is nascent but represents a promising opportunity for reducing customer costs and enabling a lower-carbon electricity grid. With the rate of spending on distribution infrastructure increasing, there is a pressing need to turn to approaches like NWS to minimize the impact on customer bills. At the same time, NWS can unlock additional value from DERs while also reducing net system costs, promoting the cost-effective deployment of resources that are important for both directly and indirectly reducing CO_2 emissions.

Non-wires solutions are thus a key priority for near-term action and can help lay the groundwork for future opportunities to scale the market for DERs as a core component of cost-effective grid infrastructure. Pursuing NWS today can help further develop best practices, highlight the most valuable opportunities for non-traditional solutions, and prove out the case for a more uniform, comprehensive market for NWS in the future. Specific opportunities exist in a few key areas:

- **Enabling the transparent and equitable valuation of location-specific services.** Pursuing NWS today can shed light on how location-based value can most efficiently be made transparent and accessible to DERs through programs (e.g., New York's Value of Distributed Energy Resources proceeding, or other tariff-based approaches) to encourage structural procurement of DERs where they can provide the most value. Experience in the near-term can also help increase understanding and inform the development of practices to address equity issues with geo-targeted pricing or programs to ensure customer understanding and satisfaction, even if neighbors may be faced with different rates or program options.
- **Identifying and expanding the range of services NWS can cost-effectively offer.** Early experience with non-wires solution projects can effectively test the range of distribution needs that NWS can address, fostering innovation while avoiding duplicity of pilots. Results of early projects can inform updated processes for predicting the cost-effectiveness of non-wires solution opportunities, so that projects can be screened more accurately for commercial viability.
- **Testing the relationship of NWS with related utility and regulatory efforts.** Emerging non-wires solution portfolios across the US relate directly to broader grid modernization efforts, including Integrated Distribution Planning proceedings and the concept of Independent Distribution System Operators. Further pursuit of NWS within these broader efforts can highlight how planning processes can consider NWS without requiring formal screening criteria, and how DER participation in wholesale markets may impact NWS deployment and performance as DERs are increasingly used to provide grid services at multiple levels of the grid.

Regulators, utilities, and technology or service providers all have a role to play in streamlining processes to enable a lower-cost grid. Experience to date has demonstrated a business case for NWS across a wide range of utility territories, available to be pursued by utilities and vendors as long as the right regulatory framework is in place. This report has laid out best practices and provided practical guidance for developing the key elements needed for implementation. It has also highlighted areas for future exploration as the market evolves. To further scale NWS by proving out the broader case for its application, there is a pressing need for more coordinated efforts to build on the lessons learned and find least-cost, best-fit solutions and processes that work across the wide variety of utilities and states that stand to gain.

ENDNOTES

ENDNOTES

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Guidance on DER as Non-Wires Alternatives (NWAs)

Technical and Economic Considerations for Assessing NWA Projects

3002013327

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ABSTRACT

Non-conventional solutions to anticipated distribution constraints are increasingly being considered by utilities due largely to the proliferation of distributed energy resources (DER), falling DER technology costs, and supportive regulatory directives. Although these non-wires alternatives (NWAs) present interesting opportunities for distribution planners, they also pose certain challenges given uncertainties around resource output, reliability, and cost. This report outlines key factors to consider when evaluating the merits of an NWA project and offers insight from real-world initiatives to further inform associated utility strategies.

The key considerations presented in the report are organized into four thematic categories:

- **Locational considerations.** Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- **Temporal considerations.** Those concerning resource availability, output variability, sustainability of response, and resource lifetime.
- **Additional design considerations.** Those encompassing the sizing of NWAs, alternative lead times, reliability, customer participation, and third-party contractual arrangements.
- **Economic considerations.** Those regarding the costs and benefits of NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

The considerations within each category, along with their impacts on the distribution planning process, are initially discussed. Subsequently, three NWA projects are profiled—two existing, one proposed—to highlight the locational, temporal, design, and economic rationales informing their structural development. Taken together, the key considerations and case study examples are intended to help guide utility thinking around successful NWA strategies for meeting short- and long-term grid planning and management objectives.

Keywords
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EXECUTIVE SUMMARY

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PRIMARY AUDIENCE: Utility distribution system planners

SECONDARY AUDIENCE: Other utility staff and researchers involved in distributed energy resources (DER) integration

KEY RESEARCH QUESTIONS

How should non-wires alternatives (NWAs) be considered, both technically and economically, as part of the distribution planning process? What real-world approaches can help inform future utility NWA strategies?

RESEARCH OVERVIEW

Key factors to consider when evaluating the merits of an NWA project are initially categorized and discussed; these include locational, temporal, design, and economic considerations. Three real-world NWA case studies—two existing, one proposed—are next presented to highlight how several of the previously described key considerations informed the projects' structural development. Findings are intended to help guide utility thinking around successful NWA strategies for meeting short- and long-term grid planning and management objectives.

KEY FINDINGS

- Utilities must have visibility, control, and site guidance of DER for these resources to be integrated into the system as an NWA.
- Given the relative immaturity of DER (that is, their limited field deployment), much is still to be learned about their ability to both technically and economically meet NWA objectives.
- Although additional considerations must be made for DER to be recognized as an NWA, the general steps of the planning process—1) identify expected system constraints, 2) assess potential resource availability, 3) design a set of mitigation alternatives, and 4) alternative evaluation and selection—do not need to change.
- An emerging subset of NWA projects is departing from historical approaches that exclusively apply demand-side management schemes (for example, energy efficiency and demand response measures) and is instead employing energy-exporting resources—such as solar photovoltaics (PV), fuel cells, combined heat and power (CHP), wind, and energy storage—to achieve both short- and long-term goals.
- NWA initiatives often serve as a testing ground for technology applications, use cases, and business model proofs of concept. To date, their justification is often tied to regulatory policies. Meanwhile, project economics tend to be context-specific.

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- Example NWA projects often include risk mitigation strategies and contingency plans to ensure reliability. This could include features such as modular sizing to adjust for future growth, using portfolios of DER with different locational and temporal characteristics, redundancy in communications infrastructure to ensure constant connection with DER systems, or on-call contingency generators in the event of a battery outage.
- Recognizing non-traditional (and non-distribution) related value streams from DER—such as avoided energy costs and voltage regulation—and/or taking advantage of supportive regulatory cost recovery rules may be key to meeting economic thresholds and, in turn, greenlighting NWA projects.

WHY THIS MATTERS

Non-wires alternatives are becoming more prevalent. Their characteristics and impacts need to be better understood to effectively integrate them into the distribution planning process, inform their strategic evaluation, and comply with emerging regulatory and policy directives.

HOW TO APPLY RESULTS

Considerations and guidance can be incorporated into utilities' distribution planning processes and practices. Learnings can be taken from the existing and proposed projects outlined in the case studies.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- The report *Incorporating DER into Distribution Planning* (3002010997) is a prerequisite to this report.
- A parallel research effort undertaken in 2018 examined how to determine the impacts of groups of DER on distribution systems from the perspective of hosting capacity. Findings are available in the report *Examining the Technical Distribution System Impacts of Mixed DER Groups* (3002013373).
- Future work in 2019 will include the development of automated methodologies for identifying and evaluating both traditional and non-wires alternatives.

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PROGRAMS: Integration of Distributed Energy Resources, P174; Distribution Operations and Planning, P200

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1
INTRODUCTION

Characterizing the Existing Planning Process

Planning for the future electricity system is a critical task that every electric utility must undertake to ensure that a safe and reliable supply is maintained for all customers. However, at the distribution level this task is becoming increasingly complex due to the emergence of distributed energy resources (DERs) and evolving load.

While distribution planning is a process that can vary among utilities, it usually follows the same general steps shown in Figure 1-1. The first step of the process is to identify the expected system constraints that will impact a utility's ability to reliably service its customers. This is typically accomplished by performing a study that incorporates forecasted growth and system changes to determine when and where constraints are likely to arise. Constraints on the as built system could occur due to geographical expansion into new developments or from changes in load on the existing system. When constraints are recognized, resources suitable for mitigating the issue are then identified. Traditionally, these "resources" are system asset upgrades, new construction, or system changes, such as the transfer of loads between feeders.

Once the potential options have been identified, a suite of alternatives can then be designed to meet the specific need. Finally, once the set of alternatives has been identified and designed, each one can then be evaluated and the best option selected for implementation based on the needs and objectives of the system. Typically, the least cost alternative is chosen, but other criteria – such as reliability – can also be considered.

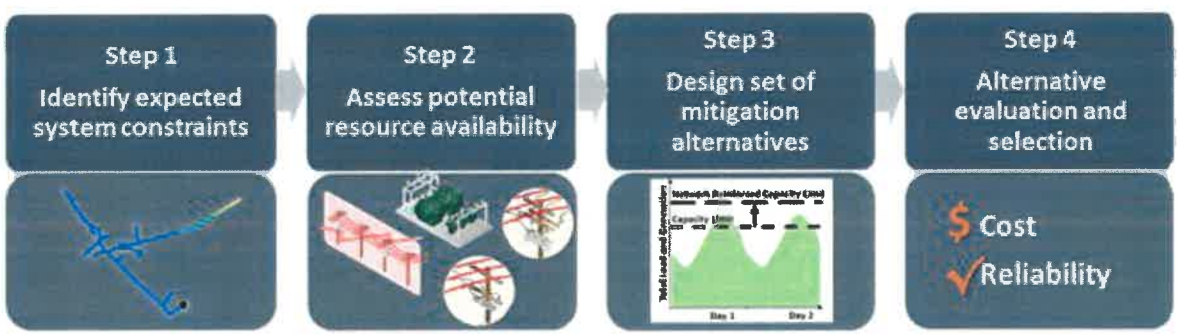

Figure 1-1
Distribution planning process steps

DER Accommodation versus Integration

The grid connection of distributed energy resources is becoming more common. Photovoltaics (PV), battery storage, electric vehicles, and various other technologies are emerging at the distribution level in different capacities. This presents both new challenges as well as the opportunity for innovative solutions from a distribution planning perspective. DERs can be viewed from two overarching perspectives, depending on their characteristics and the driver(s) for their grid connection:

1. as resources that may require mitigation and need to be accommodated at the distribution level, or
2. as resources that can be integrated into the distribution system as alternative solutions to traditional distribution upgrades.

Not all DERs will fall cleanly into one category or the other, however. From a distribution planning standpoint there is a spectrum between fully accommodating and fully integrating DERs, as shown in Figure 1-2. The influence that the utility has on site guidance, control, and visibility of a particular resource determines where on the spectrum that resource will lie. Organically growing customer-driven PV, for example, which the utility has no visibility or control of, would lie on the accommodating end of the spectrum shown by the red arrow. A utility-owned combined heat and power (CHP) plant that is installed and controlled by the utility would, meanwhile, lie on the integrating end of the spectrum, as shown by the blue arrow. A distribution connected storage system that has a primary service to provide frequency response for the transmission system, but that the distribution utility has visibility of, would need to be accommodated at the distribution level. But the distribution utility having visibility means that the resource would lie slightly towards the integration end of the spectrum, where the yellow arrow is located.

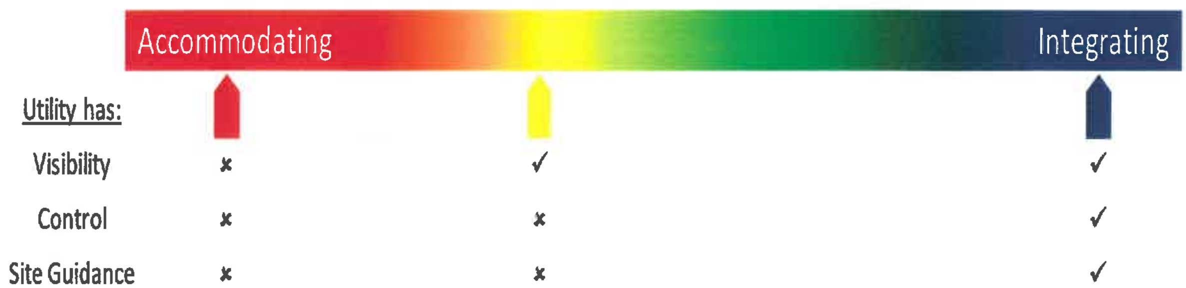

Figure 1-2
Spectrum between integrating and accommodating DER

Regardless of whether DERs are being accommodated or integrated, they must be included in the overall distribution planning process. The high-level steps outlined in Figure 1-1 do not need to change, but consideration must be given to how DERs will modify specific parts of each step. This topic is discussed in further detail in [1].

Non-Wires Alternatives

A non-wires alternative is defined as a utility-driven solution to an identified distribution constraint that defers or eliminates the need for a traditional distribution upgrade.

Non-wires alternatives (NWAs) are resources that fall towards the integrating end of the spectrum in Figure 1-2. In the NWA definition shown in the blue call-out box at right, traditional distribution upgrades are classed as mitigation alternatives that are currently used by distribution planners (e.g. reconductoring, substation upgrade, capacitor/regulator additions, load transfer, etc.). NWAs, meanwhile, could comprise PV, wind, storage, fuels cells, as well as demand response (DR) schemes and energy efficiency (EE) measures. The distribution constraint may arise as a result of increasing load or a desire to facilitate more distributed generation, depending on anticipated growth and the requirements of the distribution planner. A critical aspect of an NWA, however, is that the solution is driven by the utility and its obligation to serve its customers. DER may appear organically and offset the need for a traditional upgrade, but this should be regarded in the same way as lower than anticipated growth — a change in the plan rather than an NWA, as the utility does not have a need for that DER to serve its customers reliably. It is also important to note that although NWAs are applicable at all levels of the power system, a resource that is employed as an NWA for the transmission system may not provide relief for distribution constraints.

Although most NWAs will lie firmly on the integrating end of the spectrum in Figure 1-2, longer-term planning will allow some resources which fall closer to the accommodating side to also be considered as NWAs. Schemes such as energy efficiency, demand response, incentives, and time of use tariffs, while driven by the utility for the purposes of deferring upgrades, likely do not have the same level of utility site-guidance as other resources. These types of resources can still be thought of as NWAs, but only in the context of a long-term planning horizon for resolving wider scale constraints rather than a short-term horizon focused on localized constraints.

NWAs can be applied to resolve a range of distribution constraints, and just like traditional solutions, certain resources will be more suitable for resolving specific constraints than others. Table 1-1 shows the applicability of various resources for resolving feeder constraints, both for grid-side and NWA solutions. There is more certainty with grid-side alternatives: the solution either is or is not able to resolve an issue. For NWAs, dispatchable resources should be able to resolve any issues, however the suitability of non-dispatchable and variable resources for constraint relief are less clear-cut. Non-dispatchable and variable resources may be able to resolve thermal and voltage constraints, but further consideration of their technical capabilities is needed. These considerations are discussed in detail in Chapter 2.

Table 1-1
Suitability of different alternatives for relieving key feeder constraints

	Alternative Type	Capacity for Additional Load	Capacity for Additional Generation	Over-Voltage	Under-Voltage
Grid-Side	Reconfiguration	Yes	Yes	Yes	Yes
Grid-Side	Reconductoring	Yes	Yes	Yes	Yes
Grid-Side	Transformer upgrade	Yes	Yes	Yes	Yes
Grid-Side	Voltage uprating	Yes	Yes	Yes	Yes
Grid-Side	Voltage regulator	No	No	Yes	Yes
Grid-Side	Capacitors	No	No	No	Yes
Grid-Side	Voltage control settings	No	No	Yes	Yes
NWA	Dispatchable resource	Yes	Yes	Yes	Yes
NWA	Non-dispatchable resource	Maybe	Maybe	Maybe	Maybe
NWA	Variable resource	Maybe	Maybe	Maybe	Maybe

Yes Maybe No

Beyond relieving distribution constraints, NWAs can provide additional benefits to utilities and power systems that conventional distribution system solutions cannot. Outside of the times that the resource is being utilized for its primary distribution objective, certain types of NWAs have the potential to provide ancillary services to the bulk system and participate in markets. For example, energy storage can be used for energy arbitrage or voltage regulation among other "value stack" services. Energy efficiency measures or combined heat and power can reduce baseload energy needs outside of peak times. Furthermore, in applicable situations, renewable NWAs can contribute to mandated renewable portfolio standards and/or offset carbon taxes.

2
CONSIDERATIONS FOR NON-WIRES ALTERNATIVES

Distributed energy resources present a unique opportunity for distribution planners to provide innovative and potentially more tailored alternatives to traditional distribution upgrades. However, NWAs may not be directly comparable to traditional solutions, and will likely require additional technical and economic considerations to ensure that reliability of service is maintained. These considerations can be split into four categories:

- *Locational considerations*: Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- *Temporal considerations*: Those concerning resource availability[1], output variability, sustainability of response, and resource lifetime.
- *Additional design considerations*: Those encompassing the sizing of NWAs, alternative lead-times, reliability, customer participation, and third-party contractual arrangements.
- *Economic considerations*: Those regarding the costs and benefits associated with pursuing NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

Locational Considerations

The location of a specific distribution issue will impact the resources that are available to resolve that issue. When considering an NWA, it is therefore important to make a number of geographical- and locational-based considerations regarding spatial requirements and feeder siting.

Spatial and Siting Limitations

Spatial requirements can be both a limiting factor and a benefit for NWAs. For certain types of DERs, such as wind or large-scale PV, large areas of land are required. This means that if the need for relief arises in a highly populated urban area – which is often the case due to the correlation between population and electricity demand – these resources would not be suitable mitigation solutions.

Traditional solutions can suffer a similar fate in situations where there is limited physical space for upgrading a transformer or installing a regulator. In these instances, certain types of DER can be more appropriate solutions. Demand response, for example, is an NWA that does not have any spatial requirements and thus may be a suitable alternative to a transformer upgrade if the existing transformer is only overloaded at certain peak load times. The Brooklyn Queens Demand Management (BQDM) project, described further in Chapter 3, is another example. In

[1] The ability of DER to be available when needed could be defined as 1) an instant in time (i.e. time of day), 2) a duration of time (seconds vs. hours), 3) a certain frequency (i.e. once per hour vs. once per year), or 4) length of planning horizon (i.e. short- or long-term solutions).

this case, the traditional solution of expanding or installing an additional substation would have been extremely costly given the value of land within New York City. Instead, a portfolio of energy efficiency and DER solutions were deployed as part of the BQDM initiative that did not incur the same limitation.

Separately, suitable resources may exist in terms of their availability and spatial requirements, but that may be limited geographically on some external basis. Land use or planning permission is one example of this; certain sites may be restricted in the way that land can be used, there may be protections around nature and wildlife, land may be zoned for specific purposes such as housing, or land owners may be unwilling to sell a particular site. Another example is safety and access restrictions; potential NWA locations might not be easily accessible by fire departments, may obstruct access to other locations, or weaken structures and prove dangerous in the case of a fire.

Location of the Constraint on the Electrical System

Depending on the issue that arises as part of the planning study, the resources being employed for mitigation will likely need to be installed at a particular location on a distribution feeder for maximum effectiveness. If thermal constraints are the predominant issue, the NWA will need to be located downstream of the affected element. If voltage violations need to be relieved, resources are best located as close as possible to the electrical bus with the violation.

Additionally, considerations about the characteristics of the circuit itself and how it is operated need to be made. One of the most important of these considerations is hosting capacity. When installing a particular resource to mitigate a constraint, care needs to be taken to ensure that the NWA itself will not cause problems at other times. For example, if a planning study identifies that a line on a feeder will become overloaded during peak load times, and a PV system is deployed in order to resolve that overload, it is important to examine whether that PV system in that location could cause overloads or overvoltages during minimum loading conditions. This can be achieved by performing a hosting capacity analysis.

Another consideration that must be made regarding location on a circuit is the switching or reconfiguration possibilities of radial systems. Many utilities employ feeder switching to meet growth, for maintenance, or as part of their day-to-day operations. However, this switching may reduce or negate the effectiveness of an NWA. A resource that was downstream of a constrained asset may not be there to provide relief after a reconfiguration.

This is illustrated by the simple example given in Figure 2-1, which shows two substations with a feeder in between that can be reconfigured by opening/closing the two connecting switches. In Configuration 1, an NWA is installed at Bus C to mitigate the transformer overload. If, however, the circuit needs to be reconfigured to Configuration 2, the NWA at Bus C is now connected to the neighboring transformer and not the overloaded one, meaning that relief is no longer available for the overloaded transformer. This is an illustrative example, but in reality configurations may be much more complex, particularly in meshed systems. Therefore, detailed analysis may be required to ensure resources are located where and when they are needed.

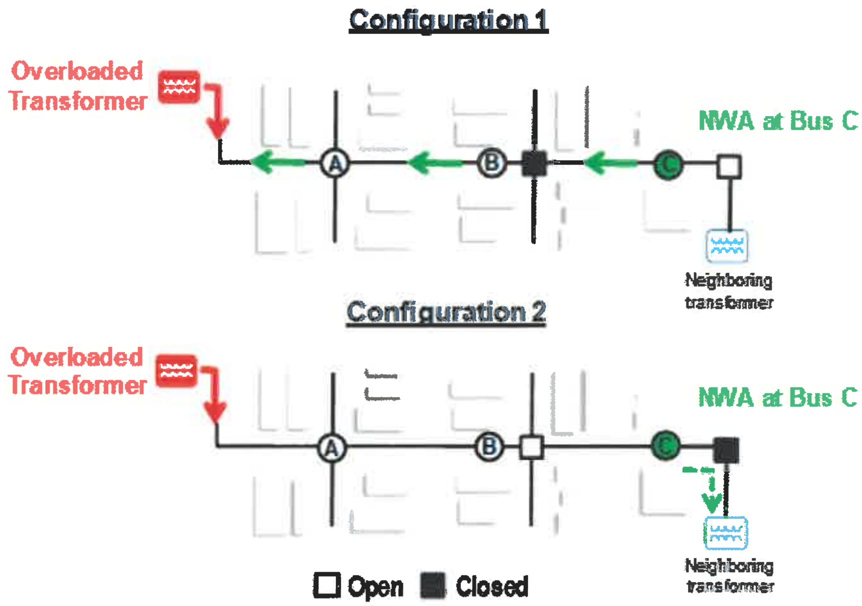

Figure 2-1
Example of reconfiguration impact on NWA effectiveness

Networked or meshed systems can add an additional layer of complexity. Unlike radial systems, networked systems are characterized by complex and multidirectional power flows, so the effect of DERs located electrically "close" to a violation may become dispersed. In some cases, dispersion is so significant that the DERs may only deliver a fraction of their nameplate capacity toward mitigating a violation. Hence, for systems with significant meshing, potential NWAs may need to be oversized to provide the necessary relief.

Temporal Considerations

Each type of DER has its own temporal characteristics that must be taken into account when planning an NWA. If a resource is available, the specific resource characteristics, combined with the characteristics of the distribution issue, will define whether that resource is suitable for mitigating the issue, and how the resource will compare to a traditional solution in a number of key aspects.

Resource Availability

Linking back to the locational considerations previously discussed, the geographical area or region under study will inherently limit the types of resources that can be considered as part of an NWA. Depending on the climate, weather, terrain and other factors, certain types of fuel sources, and thus DER, may not be available in a sufficient capacity to effectively resolve the local issue. The suitability of PV as an NWA, for example, is dependent on the amount of irradiance an area receives (see Figure 2-2). This value will vary day to day and season to season, so aligning expected irradiance during the constraining time period is important.

Average seasonal wind speeds and altitude are significant determinants of wind energy's suitability as an NWA. At higher altitudes wind speeds tend to be greater, however at too high an altitude access would likely be an issue for installation and maintenance. Although fuel cells do rely on the availability of a fuel source, that fuel source (e.g. natural gas or methanol) can be very flexible. Similarly, storage does not depend on the availability of a particular fuel so is suitable for most areas. Other types of NWAs, such as demand response or energy efficiency programs, while not fuel dependent, do rely on a type of resource in the form of flexible load and consumer participation. These resources necessitate different considerations, such as the load composition and type of customers in an area, as well as their willingness to participate in particular programs and the incentives that may need to exist to achieve that participation.

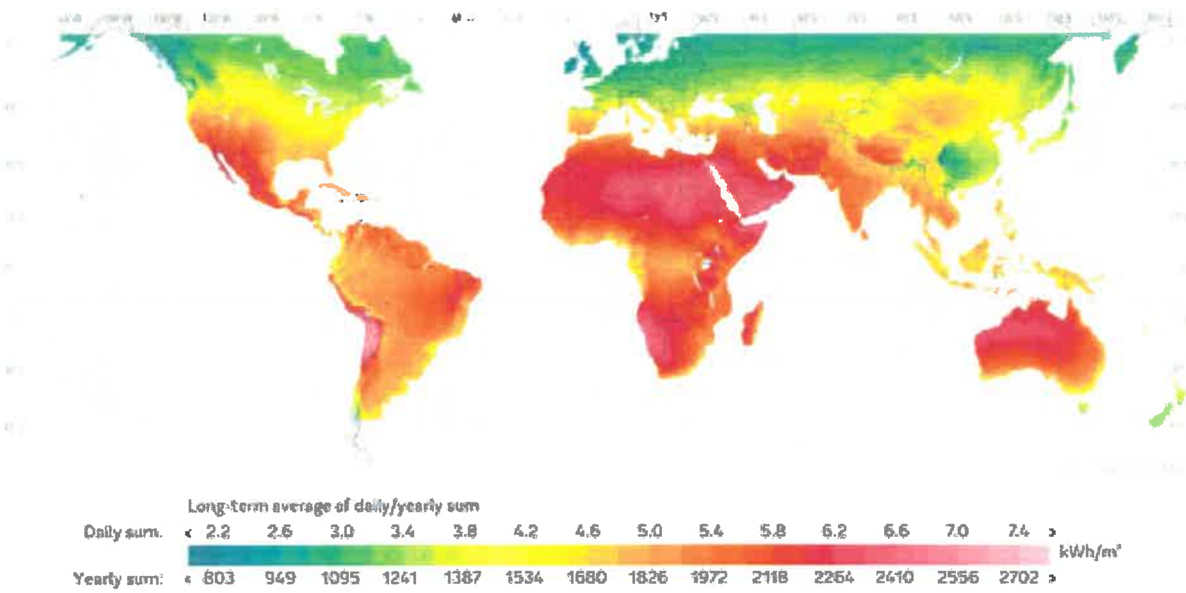

Figure 2-2
Global Horizontal Irradiation

Source: Solar resource data obtained from the Global Solar Atlas, owned by the World Bank Group and provided by Solargis (http://globalsolaratlas.info)

Output Variability and Temporal Behavior

Because many DERs rely on some type of fuel source to be available, or on external factors to achieve results, one of the biggest concerns that emerges when considering an NWA is whether the resource will be available to provide support when it is needed. This is dependent on the variability of the resource output, which differs greatly among various DER types, and is not something that typically needs consideration for conventional solutions.

Resources that are fueled by renewable sources such as PV and wind tend to be the most variable. The output from PV varies depending on temporal and meteorological factors such as the time of day, season, and weather (primarily cloud coverage). Other relevant factors relate to the PV installation itself, such as capacity, whether it is fixed tilt or has a tracking system, and the inverter specifications. Sunrise and sunset times are known precisely throughout the year, and combined with the system's specifications can provide a forecast of what the ideal output should be. This ideal output provides a window during which PV can potentially be used as an NWA. It is therefore important to consider the temporal aspect when performing the initial planning study.

Even though the ideal PV system output can be determined relatively easily, significant fluctuations from that output are likely due to weather changes. Temperature can affect PV system production, as PV arrays become less efficient at high temperatures. The factor that contributes most to PV's variability is, however, cloud coverage. A change in cloud cover can cause PV power output to rapidly drop from 100% to 0% or vice versa. Furthermore, the same level of peak demand could occur on a clear sunny day as a cloudy humid day due to air conditioning load, and although PV could relieve constraints associated with the former, it may not with the latter.

Figure 2-3 shows a box-and-whisker plot of PV output in July for eight PV systems in a sunny region over four years. The plot conveys the PV output minimum and maximums (end of whiskers), as well as the median (the line in the box) and quartile values (top and bottom of the box) recorded for each hour of the day in July. The simple takeaway: PV output can vary even in a sunny region for the best month of the year.

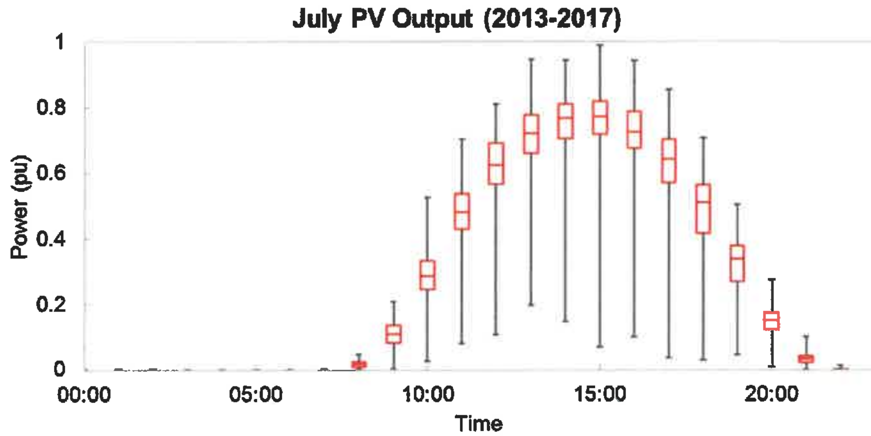

Figure 2-3
Box and whisker plot of 4 years of hourly PV output in July for a sunny region

Wind presents similar challenges, and can in fact be more variable than PV. Like PV, multiple factors related to the wind turbines themselves impact system output, such as capacity, hub height, and blade length. Wind speed is, however, the most variable determinant of output. Wind is a resource that can change seasonally, daily, hourly and even sub-hourly. Some notable trends have emerged, but are localized and not guaranteed: 1) wind speeds tend to be higher in winter and lower in summer, and 2) in certain areas wind can peak in the morning. Due to the fact that wind cannot be relied upon to be available when needed, it is typically not a feasible NWA on its own.

The output variability of EE and DR depends primarily on the load composition and consumer participation. Customer participation has a more significant effect on the total capacity of these resources and will be discussed in further detail later below. The load composition is a factor that is more likely to impact the output variation of such resources. EE programs, for example, usually target specific inefficient technologies that can be upgraded, such as incandescent lighting or hot water heaters; therefore, typical profiles for these specific devices need to be analyzed to determine how the response will affect the overall load profile at certain times of day and year. For instance, more efficient water heaters would reduce consumption in the morning and evening, improvements to lighting efficiency would have a more consistent reduction throughout the day and an increased reduction in winter versus summer. For DR, the primary concern is usually the load composition during peak load times. The appliances being utilized during that time will determine the potential response that can be achieved. The utility will also typically send a signal during these times to trigger DR, therefore there is a degree of dispatchability around the output from DR, although the level of response, as with EE, will depend on customer uptake.

Resources such as fuel cells or CHP plants tend to have a more reliable output since their fuel source can be stored onsite to provide greater availability. Battery storage, although more limited in terms of their energy output than fuel-based resources, is a dispatchable resource. System production will vary throughout the day, however it is often controlled by the utility to achieve a specific objective. Therefore, once the control logic has been planned and implemented correctly to provide temporal adequacy, storage should provide a reliable output.

Of note, although the output of individual resources may be too variable to rely on for grid support, diverse portfolios of DER can often provide more reliability, flexibility and controllability than a single resource. In particular, pairing storage with more variable resources, such as wind or PV, can offset some of the fluctuations that can occur, and ensure that output is available when the variable resource is not producing. Similarly, having a large number of smaller resources can provide a greater degree of reliability than relying solely on a single large unit. Portfolio design is discussed in further detail later in the report.

Sustainability of Response

Related to output variability, sustainability of output can be another important consideration for NWAs. With most traditional mitigation alternatives, sustainability does not have to be considered, since equipment such as conductors or capacitors are not reliant on a specific resource being available and are not energy limited. However, a distribution constraint may last for a sustained period of time, and if an NWA solution is being deployed it must be able to provide support for the full duration of the constraint. For renewable resources like PV and wind, sustainability is not guaranteed due to the output variability described in the previous section, although probability assessments can be employed to statistically describe the sustainability of the resource. EE measures may be able to reduce demand for extended periods of time depending on the targeted appliances and their typical duration. Ideally, DR should be able to sustain a response for as long as the price signal dictates. However, in reality, there is a limit to how long consumers are willing to offset their usage. They may be happy to delay their shower for two hours but not four, for example.

Storage systems are energy limited, meaning that they can only provide a response for as long as they've been designed to do so. They also need the time to both charge and discharge, so the time required to get the storage to the state of charge that is needed to relieve the distribution issue is another important consideration. As such, the duration and temporal aspects of the distribution constraint are key when considering storage as an NWA. The power and energy ratings of a storage device must be designed to meet the maximum power and total energy required by the constraint, and also be able to collect or deplete the energy required by the constraint outside of the constraint window, without causing additional distribution issues. The grey area in Figure 2-4 shows the storage energy requirement for discharging to ensure that demand does not exceed the given limit in red. However, the total area in green that is available for recharging is less than the grey area, so if the battery was sized based only on the grey area, it would not have enough time to recharge fully to relieve the distribution constraint. Further discussions regarding sizing of NWAs is discussed later.

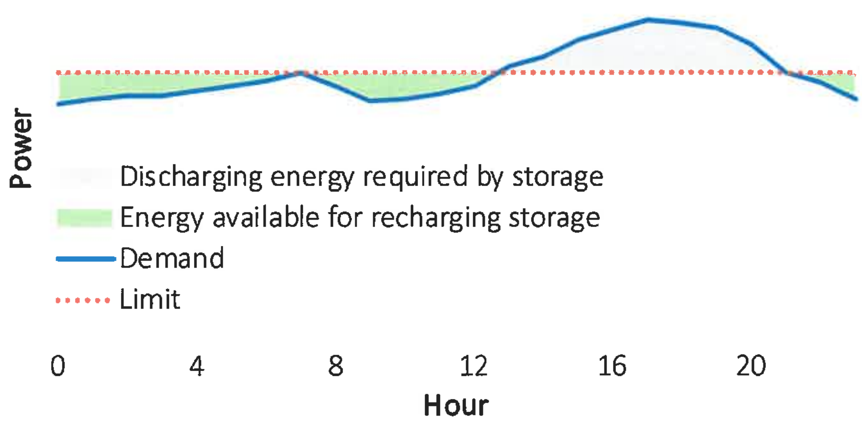

Figure 2-4
Example of energy consideration for storage as NWA

Resource Lifetime (Planning Horizon)

Traditional distribution assets have been widely used for many years. As such, there is a wealth of experience regarding their typical lifetimes. Conversely, a lot of DER technologies are relatively new, and have not accrued the same level of field experience to assess their long-term performance. Furthermore, many DER technologies are composed of a number of different components, including individual modules, inverters, and communications devices, each of which has its own lifetime and will contribute to the overall expected life of the NWA.

Of the renewables-based technologies, wind turbines have had the most significant opportunity for field testing, with some of the earliest installed turbines now coming close to the end of their design lifetimes – typically 20 years. Some turbines operate beyond typical turbine design lifetimes, however, and in these cases, it is important to reassess the remaining useful lifetime of the asset so that it can be decommissioned before complete structural failure. In the coming years, more turbines will surpass their 20-year design lifetime and more data will become available, which will be valuable in assessing whether longer typical lifetimes for turbines are feasible.

PV has had fewer years of field testing than wind, in most cases less than ten years, therefore some assumptions have had to be made about PV lifetime based on modelling and simulation. Average design life for PV modules is in the range of 20-25 years, with output degradation rates typically ranging from 0.7-1.5% per year depending on the technology [2]. These can vary significantly, however, due to stresses caused by localized weather and climate conditions, such as extreme temperatures or storms, as well as manufacturing and installation oversights.

Field experiences with the lifetime of energy storage are few and far between, as the technology is still at an early stage. For batteries, it is not just the number of years that determines lifetime, but a combination of time and charge/discharge cycles. The asset will age over time depending on material used, local conditions, among other things, but cycling accounts for the majority of degradation. As such, most vendors will list number of cycles as the lifetime metric. Typically, these fall in the 1000-5000 cycles at 80% depth of discharge [3].

PV inverter lifetimes (~15 years) tend to be 5-10 years shorter than module lifetimes, and thus must be replaced during a PV system's lifetime. Although additional industry analysis is needed, inverter lifetimes may also be shorter than expected energy storage system lifetimes.

NWAs that are third-party owned or operated require additional considerations in terms of lifetime. If a utility is depending on a third-party asset to be available long term and a company goes out of business, or EE or DR customers move or decide they no longer want to participate in a program, that resource is no longer available. Although these types of arrangements may have contracts in place, the long-term availability of the resource is inherently uncertain. It is important for a utility to be aware of this additional risk when considering these types of resources as NWAs.

A key takeaway, particularly in terms of DER lifetimes, is that a lot is still largely unknown. In the coming years it will be of utmost importance to gather the data and learnings from deployments currently in the field, as these will help inform considerations for using DERs as non-wires alternatives.

Additional Design Considerations

Sizing

The size of any mitigation measure will be dictated by the severity of the distribution issue. If the distribution issue is a thermal one, the size of the overload will determine the capacity needed for a solution. Similarly, if voltage is the primary constraint, the extent to which the voltage exceeds normal limits will define the size of the solution. With conventional solutions, these are typically the only parameters needed to determine size; for NWAs, however, additional considerations need to be made, which relate back to the earlier discussion around variability and sustainability of NWAs.

In terms of variability, the timing of the constraint must be compared with the typical output of the resource at that time. If the resource is not expected to provide its maximum output when the constraint occurs, then the size of the resource will need to be scaled up. For example, if an overload of 1 MW occurs at 3pm, and expected PV output at 3pm is 0.7 pu, then the size of a PV system required to resolve the 1-MW overload is 1.43 MW. Determining the expected output of variable DER can often present a significant challenge, as the range in output at the time a constraint occurs may be considerable, as was highlighted in Figure 2-3. Taking a conservative approach and assuming an output on the low side of the range may mean the size of the resource is unreasonably large. Conversely, assuming an output at the high side of the range poses risk in terms of the resource being available when needed. Probabilistic approaches can be employed to determine likely outputs for DER, as well as how the output aligns with the need. Furthermore, diversifying an NWA with multiple DER types can provide increased output reliability.

Certain resources require both a power as well as an energy size to be specified. This relates back to the sustainability of the response discussed in the temporal considerations section. If a constraint is prolonged, or arises repeatedly, ensuring the NWA is sized appropriately to provide a sustained response is critical. In order to determine the required energy size, the sum of the energy required by the constraint over the duration of the constraint should be calculated. For resources like storage, which also require time to charge/discharge to mitigate a constraint, care should be given to ensure that the time available outside the constraint window is enough to re-charge/discharge, as necessary; otherwise, the energy size will need to be increased accordingly.

Location also plays into the sizing of an NWA. The distributed nature of certain resources, such as demand response, means that sizing the resource based on the size of the constraint will likely not be sufficient. The potential losses that would be incurred by transferring the power should also be taken into account, which will result in an increase in the size of the NWA. Moreover, if the system experiencing a constraint is meshed rather than radial, the dispersed nature of the power flows will necessitate a larger NWA size.

Sizes of traditional assets usually increment in steps, therefore the size of the asset chosen typically reflects the size of the constraint plus a degree of headroom. For example, if a 2 MVA transformer is predicted to be overloaded by 0.2 MVA, the next available size for a replacement transformer could be 2.5 MVA, giving an additional 0.3 MVA of headroom. Further, it may be a prudent practice to standardize upgrade designs and sizes to reduce costs. This may add headroom if the prudent upgrade incorporates a larger incremental step size due to the implementation of the standard design rather than customized smaller incremental step. This additional headroom may be beneficial if actual growth exceeds forecasted growth. As sizes of DER tend to be more granular than conventional solutions, it is unlikely that an NWA will provide headroom unless designed to do so. This is yet another consideration that should be made when sizing an NWA.

Lead-time

The initial planning study will determine a future point in time by which a constraint is anticipated to arise and a solution is needed. This will inform the available timeframe for identifying, procuring, and deploying a potential alternative. The lead-time for alternative projects can vary significantly, depending on the scale of the required project. Constraints that are expected in the short-term may not be resolved by a solution that requires longer construction or installation lead-times. For example, programs or schemes that require third party participation will likely have a longer lead time and be unsuitable for short-term planning needs.

Traditional upgrades are typically designed and implemented by the utility in-house, therefore the lead-time for these types of projects depends primarily on the installation time of the project. For an NWA, there is usually a significant amount of time required for solution procurement and deployment [4], which can add a degree of uncertainty to the overall lead-time of the project. Once a utility decides that an NWA is a feasible solution to the distribution constraint, a request for proposals is typically issued. A sufficient window of time must be allowed for bids to be prepared and submitted. Once that window has closed, the bids must be assessed and a winning bid selected before the deployment of the solution can begin. This process can take a significant amount of time, and if the need is pressing, there may not be time to go through it. Furthermore, if none of the submitted bids meet all of the NWA requirements, then considerable time has been wasted that could have been better used developing a wires alternative.

The identified timing of the projected need is another issue to consider regarding alternative lead-times. Due to inherent forecast uncertainties, long-term planning horizons needs are more volatile or uncertain compared to identified near-term needs. As such, potential DER-based alternatives with long lead times aligned with identified long-term needs may be provided a lower valuation or prioritization, as discussed in [4]. The lower prioritization reflects the desire to minimize the deployment of alternatives that prove to be unnecessary or less economically beneficial as future needs become more certain. Conversely, DER alternatives with short lead times (e.g. portable utility-owned storage) may offer the ability to better account for planning uncertainties by providing temporary load relief while more cost effective permanent solutions are implemented.

Reliability

As with NWA resource lifetimes, DER equipment reliability and O&M needs are issues that need further testing and data collection before they can be fully quantified. There have, however, been some learnings to date from existing deployments.

In general, wind turbines are expected to be available approximately 95-97% of the time [5], with this value decreasing as the asset ages. The main reason for unscheduled downtime is due to electrical failures, mainly generator issues, followed by drive train failures like gearboxes, and structural failures which are primarily blade related. By comparison, scheduled maintenance such as inspections and site maintenance tends to require much less cost and downtime.

PV O&M trends are moving towards scheduled and conditional-based maintenance such as inspections, panel cleaning, and site management accounting for the majority of maintenance. This should, in turn, reduce the need for corrective/reactive maintenance, such as module repairs, as well as overall PV downtime [6]. O&M requirements for storage have not been well established due to lack of experience, but in general tend to be low; degradation issues tend to be more of a concern than instantaneous failure [7].

All of the aforementioned resources are also power electronics-based; they are therefore reliant not only on the dependability of their own modules, cells, or turbines, but also on the power electronics in the converter/inverter that is used to connect the devices to the grid. After generator failures, converters are the next most responsible component for wind downtime. For PV, inverter maintenance has been noted as the cause for the majority of unscheduled downtime [8].

Additionally, an increasing number of DER technologies are becoming dependent on the use of communications to achieve their objectives. This communication layer provides a degree of flexibility and control to DER solutions, but it also adds another element that demands reliability considerations. Real-time DR is a good example of a resource that relies heavily on communications to achieve a response. If the communications fail, and a signal is not communicated to the resources, then the resource cannot respond as needed. Thus, for resources which require regular updates, it is important that the communications system be monitored closely, and where possible, outfitted with failsafe options to overcome a potential communications issue.

Customer Participation

Per Chapter 1, the definition of an NWA emphasizes that resources that comprise an NWA must be procured by the utility. Therefore, this section does not discuss the adoption of customer PV or storage, as these would be considered organic growth, and should be accounted for in the planning process. Examples of resources that could be used as an NWA that also require customer participation are EE and DR, as well as incentives, which tend to be considered as part of the longer-term planning horizon.

Quantifying the expected uptake from customers for a particular program is critical to determining whether that program would be a suitable resource for deferring a distribution upgrade. To ascertain such information, one option would be to examine existing efforts, both active programs as well as pilot and demonstration projects, and gather data on adoption and participation. This would also provide useful information regarding the effectiveness of different implementation strategies and program designs. A more labor intensive but comprehensive way to determine consumer participation would be to run new pilots or demonstrations. Results from such projects would give a more accurate representation of the likely response from customers within the local area and would also allow various strategies to be tested. A deeper dive into using EE and DR in distribution planning is given in [9] and [10].

There are a number of characteristics related to customer-owned NWAs that can prioritize certain projects over others. The type of customers in the constrained area is one of these characteristics. Typically, if the load is composed of more large-scale customers, such as commercial or industrial customers, the project should have a higher priority than one where the load is composed of more small-scale customers, as fewer customers need to be engaged to relieve a constraint. In terms of number of customers, if the constrained asset serves a high number of customers, there is greater opportunity for participation than if the constrained asset serves a lower number of customers. These prioritization metrics and others are discussed in more detail in [4].

Third-Party Contractual Arrangements

Utilities could elect to contract with energy services companies and third-party providers of non-wires solutions. Understanding if there is a value proposition for deferring grid upgrades with third-party-owned DER instead of utility-owned DER is important. There may be regulatory barriers preventing deployment of third-party-owned NWAs at the distribution level. If third-party solutions are deemed prudent given the regulatory context, developing contractual arrangements that properly address liability challenges (e.g. vendor bankruptcy) and developing specific contingency plans in case NWA fail to deliver value, are relevant considerations.

Economic Considerations

The total cost of an NWA will depend on the technical design requirements given the previously discussed considerations. There are multiple factors that must be considered to yield proper economic comparison between an NWA and a traditional wires solution.

Upfront Capital Cost

The primary cost component is typically the upfront capital cost of the DER technology itself. As is usually the case with new technologies, the capital cost for DER can initially be significantly higher than the traditional upgrade alternative. But as a technology becomes more widely used, competition increases, manufacturing processes improve, and ultimately costs tend to drop over time. This has been the case for PV, with the module price dropping from $85/W in 1976 to $0.23/W in 2018, as illustrated in Figure 2-5. Similarly, wind turbine prices have fallen by 32% since 2010, and lithium-ion battery storage is expected to fall by 66% between 2017 and 2030 [11]. Therefore, when technology costs are being considered, the fact that these costs are likely to be less in the future than they are today should be taken into account. Capital costs for NWAs should include all costs, including integration costs, such as remote monitoring, control, and related infrastructure if it is required. Although schemes such as EE do not require any capital cost in terms of equipment, they may incur an upfront cost or incentive to encourage customer participation.

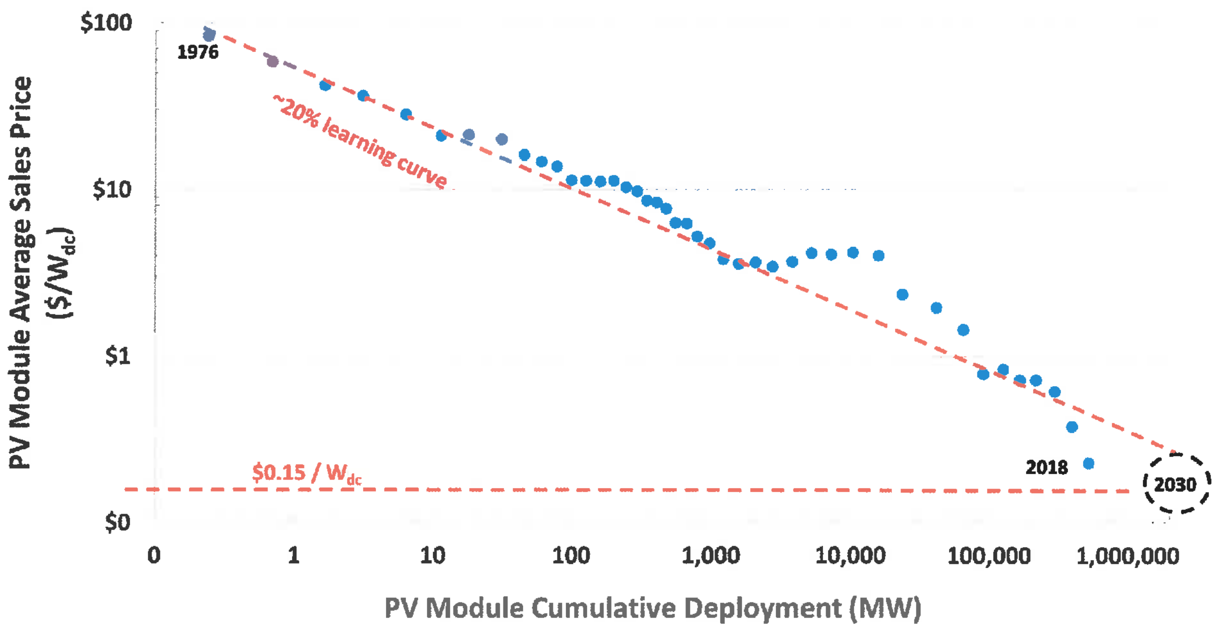

Figure 2-5
PV module price trend, 1975 to 2030E

Sources: SPV Market Research, NREL, EPRI

Operations and Maintenance (O&M) Costs

Aside from capital costs, there are additional costs associated with O&M. Fuel costs are not a concern for renewable resources such as PV or wind, but certain types of DER, such as fuel cells or CHP, are fuel dependent and thus the associated fuel costs need to be considered. Depending on the structure, certain DR programs may incur a similar "fuel" cost in the form of the payment that customers receive for reducing their demand. However, the pricing structure used for such a scheme should be designed with a least cost goal in mind.

As previously mentioned, many NWA technologies are not as mature as traditional assets and there is still a lot to be learned in terms of optimal O&M practices. For example, in some climates, panel washing can be a cost-effective practice to boost performance of solar panels while in other climates it is not. Preventative maintenance costs, such as greasing solar tracking system components or checking for cording electrical connections, can be estimated. However, there remains some uncertainty around equipment failure rates and thus reactive maintenance costs which may be significant. Maintenance practices can be optimized such that marginal O&M costs equal the marginal benefits associated with improved reliability and equipment life. These costs will become better understood with time and more widely available data.

Equipment Life and Replacement Costs

Proper economic comparison between traditional and DER solutions must also consider the lifetime and replacement costs of the solution. Accounting for the escalation or declination of costs when estimating replacement costs is important and can alter project economics. As previously mentioned, NWAs may have lifetimes that are considerably less than traditional solutions. Consequently, it may be necessary to account for the cost of an NWA needing to be replaced or upgraded sooner than a traditional alternative. Conversely, in the case where there is some uncertainty surrounding the identified distribution need, shorter NWA lifetimes could be favorable given their lower risk due to shorter cost-recovery timelines.

Other Avoided Costs

A final consideration is the impact of a given solution on other costs such as energy procurement (whether produced or purchased) or ancillary services. One advantage of energy producing NWAs such as solar PV or CHP is that they not only can help relieve identified distribution constraints but can also offset utility bulk system energy costs. Storage systems may be able to lower energy costs through arbitrage by charging during low cost hours and discharging during high cost hours. NWAs may also be able to help with voltage or frequency regulation and reduce the need for ancillary services. Both traditional and NWA solutions impact voltage profiles which, in turn, can alter consumption and system losses.

In some areas, there may be environmental regulations such as renewable portfolio standard (RPS) or a carbon tax. Implementing renewables producing NWAs, EE, or DR that reduce the need for non-renewable resources can help avoid costs associated with RPS compliance. Although the costs associated with energy, losses, ancillary services, or RPS compliance may not be primary drivers in the choice of an alternative, they could be significant and should be accounted for in the overall economic comparison.

Lastly, the flexibility and portability of NWAs may allow them to offer multiple "stacked services" throughout their expected lifetimes. For example, the ability to move a battery system elsewhere should future load growth fall short of expectations represents a comparative advantage over traditional wires upgrades which lock the utility into population and load projections that could change over time. Further, if designed to be modular, a battery facility may be able to expand at minimal cost if higher than anticipated load growth materializes.

A summary of the economic pros and cons outlined for NWAs is given in Table 2-1.

Table 2-1
Summary of pros and cons related to economics of NWAs

Pros	Cons
• No fuel costs for renewable resources • Potential for providing additional system services • Avoided costs (e.g. RPS compliance, carbon tax)	• Potentially high upfront capital costs • Uncertainties regarding O&M costs • Shorter lifetimes, need to be upgraded or replaced sooner

NWAs in the Distribution Planning Process

In Chapter 1, the existing distribution planning process was outlined with four key steps. Although DERs and NWAs will change parts of the planning process, the underlying structural steps do not need to be altered, as demonstrated in Figure 2-6.

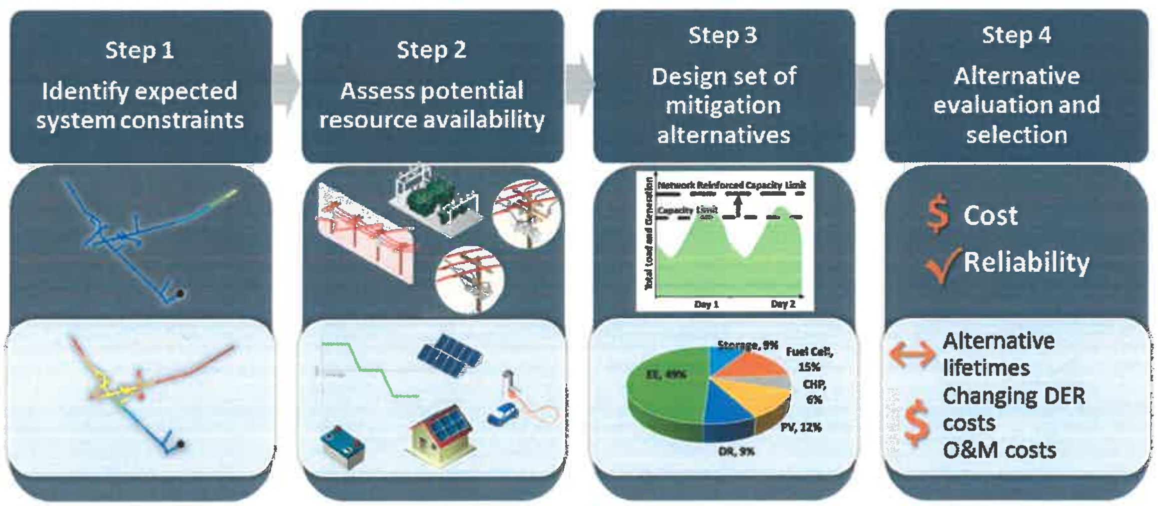

Figure 2-6
Existing and emerging distribution planning process

The steps themselves will, however, be affected by the considerations discussed in this chapter, as highlighted in Table 2-2. Locational and temporal issues will need to be considered as part of Step 2, where resource availability is identified. Additional DER design factors will need to be considered to help narrow down the set of appropriate mitigation alternatives in Step 3. Finally, economic considerations regarding both NWAs and traditional solutions will need to be compared as part of Step 4, where the most suitable solution is selected. Alternatives must be evaluated on an apples-to-apples basis, which can be achieved by defining certain metrics for project prioritization and, in turn, help ensure fair and optimal alternative selection [4].

Table 2-2
Linking considerations to planning steps

Consideration	Affected Planning Process Step
Locational Considerations	2
Temporal Considerations	2
Additional Design Considerations	3
Economic Considerations	4

Designing a Portfolio

As has been mentioned, although certain technologies in isolation may not be adequate to support the needs of the future distribution system, combining them to create a diverse portfolio of DER may provide a more reliable and sustainable NWA. The creation of a portfolio of DER would happen in Step 3 of the emerging planning process described in Figure 2-6, and must incorporate all of the previous considerations that have been discussed.

Once the available resources have been identified based on the distribution constraint and the locational considerations, the share of each resource within the portfolio must be determined – a non-trivial task. To start, the key objectives of the portfolio must be decided upon – it may be that the portfolio should be designed to minimize output variability during the time of the constraint, or to minimize the overall portfolio costs. Optimization methods are one way of calculating the ideal share of resources to achieve the desired objective, while incorporating all of the characteristics and considerations previously outlined for each resource.

3
NWA PROJECT CASE STUDIES

Non-wires alternatives have been employed for over three decades, with early demonstration projects emerging in the early 1990s. However, deployments have been both sporadic and uneven. Moreover, the vast majority of the approximately 40 U.S. projects (330 MW) implemented to date have employed targeted demand-side management approaches, largely comprised of energy efficiency and demand response measures, to offset distribution and transmission system upgrades [12].

Recently, falling technology costs, in part driven by rising deployments, as well as regulatory mandates and policy supports, have sparked a new cycle of NWA development activity that is exploring the use of energy-exporting DERs – primarily solar PV, fuel cells, CHP, wind, and energy storage (which has load and export implications) – to offer distribution system benefits. These projects are leveraging a growing body of DER operations and maintenance experience to plug distributed energy resources into a variety of NWA use cases. In this way, they are helping to evolve traditional utility planning and business models strategies for grid integrating rising penetrations of variable resources, accommodating forecasted load growth, and mitigating associated distribution system constraints.

Today, over 100 NWA projects, totaling 1.4 GW, are in various phases of pipeline development in the United States (see Figure 3-1), the majority of which are expected to come to fruition [12]. Of this pipeline capacity, about 30% is intended to defer distribution (<69 kV) infrastructure investments, via smaller, tactically focused projects (6 MW of average capacity) [13]. And looking ahead, global spending on NWAs is predicted to grow from $63 million in 2017 to $580 million in 2026, a growing portion of which is expected to be earmarked for NWAs composed of distributed generation technologies that can enable distribution deferral through strategically placed locational deployment [14].

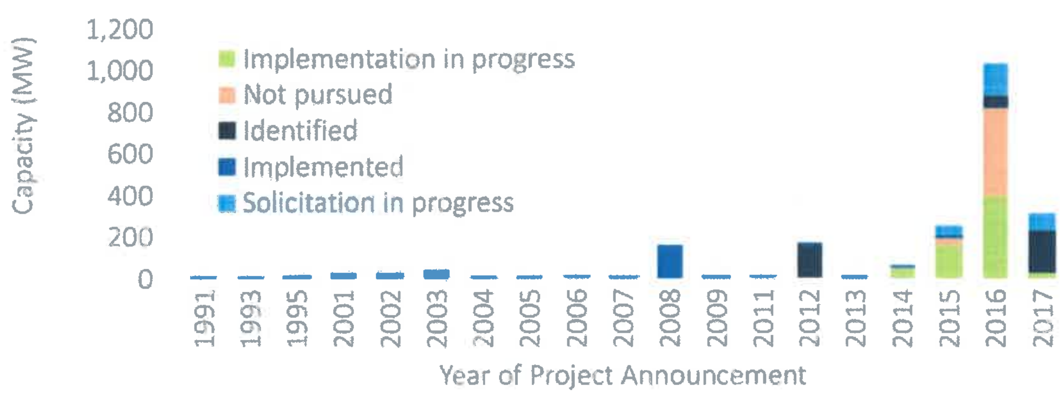

Figure 3-1
NWA Capacity by Year of Project Announcement

Source: GTM Research

This chapter profiles three real-world NWA projects – two existing, and one proposed – to highlight their locational, temporal, design, and economic considerations. The case studies examine each project's guiding rationales, and, where possible, describe identified outcomes. Their intent is to offer comparative insights that can help inform future NWA strategies for meeting short- and longer-term grid planning and management objectives.

The cases, summarized in Table 3-1, are representative of an emerging subset of NWA projects that employ energy-producing DERs largely to delay traditional distribution upgrades. (An expanded accounting of these NWA projects is available in the Appendix.) They have been selected given their collective diversity; relatively well-documented operating, financial, and performance histories; relevance to other utilities and technology developers; replicability; and potential to impart meaningful insights. Each provides an initial understanding of project background and goals, before presenting key economic and logistical issues – including benefit-cost analysis calculations and implementation approaches. Project status and next steps are subsequently discussed, and lessons learned conveyed. References for more information are lastly provided.

Table 3-1
Summary of profiled NWA projects

Utility - Project Name	Technologies / Size	Location / Status	NWA Project Summary
Arizona Public Service – Punkin Center	ES: 2MW / 8MWh	Arizona / Launched 1Q18	Battery system addressing load growth and resulting thermal constraints on a rural feeder by providing peak shaving during 20-30 peak power demand days per year. Other grid services also available via the unit (solar shifting, voltage regulation, etc.) Upshot: upgrade deferral of 16.5 miles of T&D infrastructure over rough terrain. Redundancy and design flexibility incorporated to ensure reliability, add battery capacity to meet future load growth.
Con Edison – Brooklyn-Queens Demand Management (BQDM) Program	DR, EE, PV, ES, FC, CHP, CVR: 52MW	New York / Launched 2014	BQDM employing $200M in contracts for DER, DR, and other load relieving solutions to overcome a sub-Tx feeder constraint thereby delaying construction of a $1.2B area substation, new switching station, and feeders. To date, EE programs have yielded 15 MW in peak load reductions; DR has also made significant capacity contributions; fuel cells and CHP have offered 8 MW of deliverable peak load reduction capacity. Other load relief anticipated from energy storage. Program recently extended by NYPSC.
National Grid – Little Compton Battery Storage Project	ES: 1 MW / 250 kWh	Rhode Island / In Development	To delay a $2.9 million substation upgrade, the utility proposed procuring services from a 250 kW/1 MWh, vendor-owned battery storage system to provide peak load relief through the summer of 2022. The battery was intended to predominately be used to reduce peak from 3:30pm to 7:30pm during June thru September. When not being used for peak load relief, the system was going to be allowed to participate in the ISO-NE energy market. Due to a downwardly adjusted peak load forecast and the presence of significant distributed generation able to help reduce potential grid constraints, the project was no longer deemed necessary and shelved in December 2018.

Arizona Public Service – Punkin Center

Background

In 2016, Arizona Public Service (APS) identified the need to rebuild the transmission and distribution (T&D) infrastructure servicing the rural town of Punkin Center, AZ (located ~90 miles northeast of downtown Phoenix). The town's modest, yet persistent, temperature-driven loads – rising by an average of 1-2% per year – were threatening to create constraints on the sole circuit serving the community, the 21-kV Mazatzal feeder[2], and to overload its thermal limits. Rather than rebuild 16.5 miles of poles and wires through hilly and mountainous terrain, the utility opted to pursue a non-wires alternative solution consisting of a 2 MW/8 MWh battery array that is able to provide feeder capacity through peak shaving and thereby defer system upgrades (see Figure 3-2).

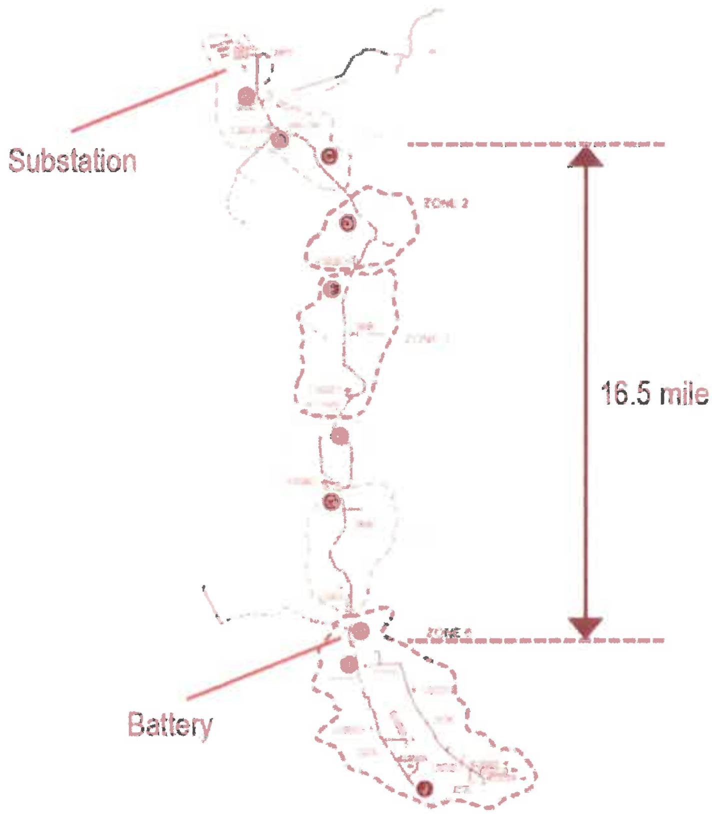

Figure 3-2
The Mazatzal Feeder, Substation, and Battery Unit Serving Punkin Center, AZ

Source: Arizona Public Service

Launched in March 2018, the Punkin Center Battery Storage Project now delivers local peak shifting services to the town's 600 residents during 20 to 30 peak power demand days per year,

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[2] The feeder has a 2R line rating of 174 A.

when local and system peaks create feeder constraints.[3] In addition to reducing delivery capacity needs, the battery unit is lowering the area's generation capacity needs, thus lessening the urgency for new generation investments. Its ability to save money through energy arbitrage (i.e. soak up negatively priced energy and dispatch it when costs are higher), is a direct benefit to the utility's customer base. Meanwhile, the NWA installation can also provide grid services to APS, such as solar peak shifting, voltage regulation, and power factor regulation. Because the system is oversized compared to the projected T&D deferral need, it has the capability to serve multiple applications beyond peak shaving simultaneously, if needed.

For APS and the utility industry at-large, the project represents one of the first strategic investments in energy storage in lieu of traditional infrastructure. As such, project findings are expected to inform APS's future NWA activities and influence other utility NWA strategies as well. For instance, APS's ability to plan, deploy, and operate the battery system in approximately nine months rather than pursue a multi-year transmission construction project – and take on the cost risks associated with accommodating 20-30 years of expected load growth that may not materialize – is expected to help prove out the effectiveness of making smaller, incremental investments in DER to help manage grid needs as they arise.[4]

Economic Considerations

APS evaluated several options to determine the least cost, best fit solution for mitigating the constraints on the T&D system servicing Punkin Center. These included diesel gensets, combined solar-plus-storage, battery storage, and a traditional line upgrade. Ultimately, the battery system was found to be the optimal alternative for economically addressing load growth concerns. According to APS, the cost of the system was less than half of the upfront expense of the traditional wires approach. Overall project costs favored the battery too.

Importantly, the Punkin Center project's circumstances contributed to its economic justification. For example, the remote location of the Punkin Center community as well as its growing load demands, the challenges introduced by the surrounding area's rugged terrain, and the battery system's added technological benefits (i.e. value streams) were key to the project's greenlighting. More generally, the technology's portability and falling costs were also a boon to its economic cost-benefit. For example, the flexibility to move the battery system elsewhere should future load growth fall short of expectations represents a comparative advantage over traditional wires upgrades which lock the utility into population and load projections that could change over time. (The battery facility is also designed to be modularly expanded if higher than anticipated load growth materializes.)

Beyond economics, regulatory considerations also contributed to the development of Punkin Center's Battery Project. For example, the utility was able to leverage the NWA effort to help

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[3] Construction on the Punkin Center Battery Storage Project commenced in fall 2017 and the system became operational in March 2018.

[4] In total, the NWA project's timeline – including business case and budget approval, RFP and contracting, EPC, commissioning and operations – took several years (2015-2018).

fulfill a 2016 obligation to develop 10 MWh of battery storage as part of the Ocatillo Modernization Project.[5]

Approach and Practical Considerations

The utility ran a competitive bidding process that resulted in the procurement of two 1-MW/4-MWh storage systems from Fluence Energy (nee AES Energy Storage). Under the terms of the arrangement, APS owns and operates the project and has a 10-year maintenance agreement with the developer. Fluence Energy is responsible for assuring that the batteries run at nameplate capacity over the life of the contract (i.e. either by servicing, refurbishing, or replacing degraded modules).

Fluence installed the battery and transformer, while APS provided the land, siting, and pad; a control house; two-way, four-way switch; and contingency generator (see Figure 3-3). To meet the project's reliability requirements, APS built in several layers of redundancy as well as design flexibility for future expansion. For example, critical spare parts, such as switchgear and transformers, are stored on-site to avoid their long procurement lead times. Meanwhile, in the event of a battery outage, APS also configured the battery site so that temporary generators can connect to a spare transformer. It additionally contracted with a local provider of diesel gensets to offer 2MW of emergency back-up, if needed.

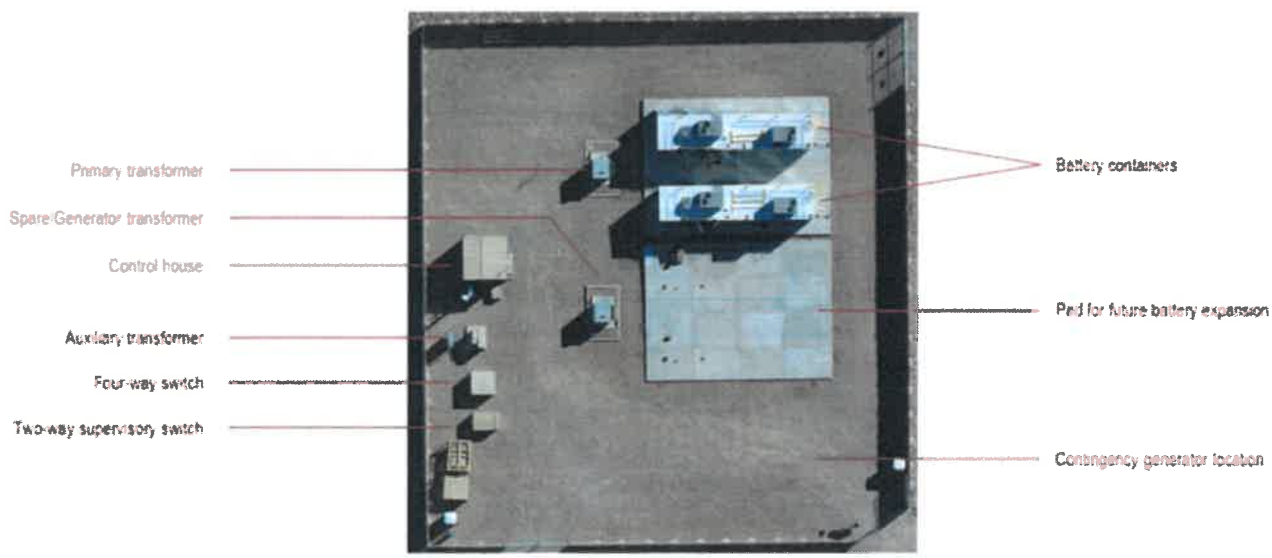

Figure 3-3
Overview of Punkin Center Battery Site

Source: Arizona Public Service

[5] This project is modernizing the Ocotillo Power Plant in Tempe, AZ. Its aim is to implement advanced technology to enable a cleaner-running, more efficient plant. APS intends to install five natural gas combustion turbines and to remove two existing 1960s-era units, among other activities.

Redundant pathways were also incorporated for critical alarms, along with well-defined responses to different communication and protection fault types.[6] To assure connection with the battery unit, APS utilizes MAS monitoring software as a primary path of communication, and spread spectrum as a secondary pathway.[7]

Meanwhile, battery dispatch occurs is three different ways. The primary method involves a routine dispatch schedule that is based on the affected feeder's historical loading. The second method transmits loading information from the feeder head, where the thermal constraint is located, down to the battery through wireless communications. A third method involves installing local metering on the feeder outside of the battery site that is hardwired into the battery controller, thereby allowing continued operations should communication with the battery system be lost. This latter approach (peak shaving mode with local metering), which has not yet been utilized as of this writing, is expected to provide better battery utilization than scheduled dispatch.

Status and Next Steps

The battery installation has been operating on a daily basis since its commissioning in March 2018, and has reportedly provided feeder peak shaving throughout the summer of 2018. Per Figure 3-4, scheduled dispatch was found to be effective on the hottest days of the summer. However, ramp limitations (17 kW/min) – put in place to mitigate issues involving the use of Integrated Volt/VAR Control (IVVC) to manage feeder voltages during reverse power flow conditions – have restricted battery capabilities. (The IVVC software used to coordinate the operation of six voltage regulators did not originally account for reverse power flow conditions that the battery unit could cause during periods of low load. As a temporary fix, the local feeder metering point was leveraged to manage the battery system's maximum dispatch.) A firmware update to Eaton's Yukon platform now allows for the continued operation of IVVC under reverse power flow conditions, consequently enabling more flexible battery operation.

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[6] Protection fault types include: Ground fault, high current fault, low current/abnormal volt. Fault, arc flash, smoke detected, fire suppression activated, and emergency machine off/E-Stop activated. Communication fault types include: APS RTU to Fluence RTAC comm. loss, APS EMS to RTU comm. loss, and Fluence 24-7 comm. loss.

[7] Spread spectrum is a form of wireless communications in which the frequency of the transmitted signal is deliberately varied. This results in a much greater bandwidth than the signal would have if its frequency were not varied.

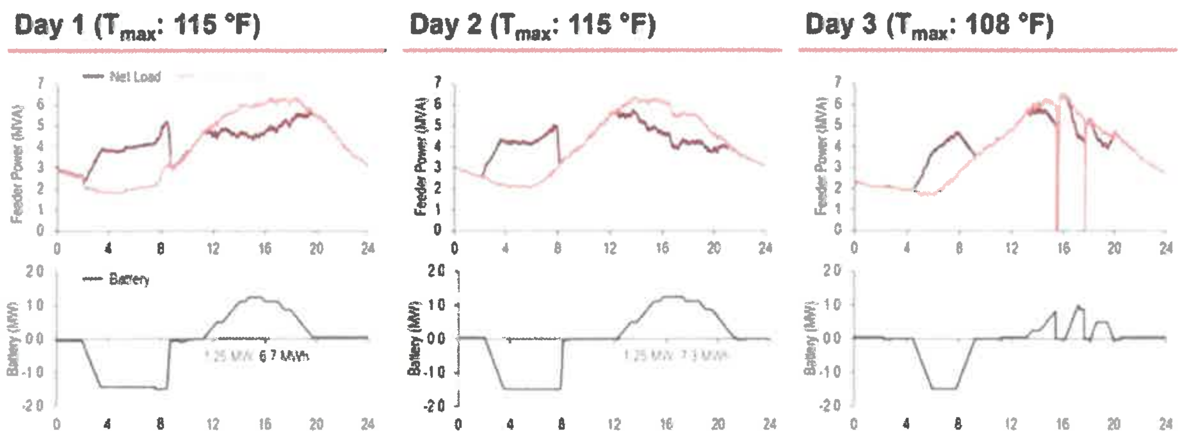

Figure 3-4
Sample Battery Performance during Three Summer Days in 2018

Source: Arizona Public Service

To improve reliability, a control feature has been added to restrict battery charge during specific times of the day, and a contingency generator has been successfully synched to the grid and tested in case of prolonged battery problems. A recent feeder cutover is, separately, relieving some load at the thermal constraint.

Based on data from April to August 2018, a range of feeder- and battery-related faults have caused operational challenges, reducing the battery's daily availability to 96.6%, slightly below the contractual requirement (≥ 98%). Encountered events have included abnormal voltages, ground fault, short circuit, a vendor server outage, and inverter replacement. With accrued project learning, APS and Fluence expect to improve the battery system's availability and performance going forward.

All told, the project has generally met APS's expectations. The utility plans to further study the battery system's performance and utilization as it evaluates the merits of pursuing other NWA initiatives in the 2020 timeframe. It will also share accrued project experiences and lessons learned with interested stakeholders, especially given the initiative's broad transferability (i.e. power reliability and basic grid operation) to other contexts.

Lessons Learned

- **Economic justification is often tied to specific project circumstances.** Punkin Center's rural location, projected load growth, the characteristics and location of the constrained T&D infrastructure, the battery unit's value streams, regulatory considerations, and management buy-in are all factor's enabling the NWA project's development.
- **Thoughtful implementation of battery storage is key to its future success.** Appropriate contingency planning and background research can help project stakeholders realize optimal battery operation, recognize the technology's realistic value propositions, and architect practical service contracts. Meanwhile, implementing the storage solution on a weak feeder can help assure that the unit (and its projected benefits) can be more readily accessed. Making adjustments to installation and operation plans as issues

inevitably arise (e.g. modifying the IVVC function, adapting dispatch options, etc.) are likely to be necessary. Rigorous planning can help avoid cost creep – especially for inaugural NWA projects.

- **Recognize the operating needs of the battery storage unit and plan accordingly.** For example, determining how a storage system will be charged and dispatched in a way that will maximize its utilization and benefit can guarantee its success (i.e. internal controls and data requirements should guide operation). Accounting for line losses can make sure that the battery is appropriately sized.

- **Incorporate appropriate levels of redundancy into the NWA solution to ensure a level of reliability consistent with traditional wires upgrades.** Practical contractual obligations (e.g. for real power availability and round trip efficiency), robust communication architecture, multiple battery dispatch options, back-up plans (e.g. contingency generator, spare transformer), design flexibility to accommodate future expansion due to load growth, and on-site critical spares can all contribute to an NWA project's reliability. These and other approaches can help inform the ingredients that should be accounted for when conducting cost-benefit analyses of battery-based NWA projects.

- **Do public outreach and education.** Keeping local organizations and residents informed about the project, its goals, challenges, and outcomes can go a long way toward generating stakeholder support useful to a project's success.

For More Information

- Punkin Center Battery Storage Video: https://www.youtube.com/watch?v=cjSRvaP7Ucg.

- Edison Electric Institute. *Leading the Way: U.S. Electric Company Investment and Innovation in Energy Storage*. Washington, D.C.: October 2018. http://www.eei.org/issuesandpolicy/Energy%20Storage/Energy_Storage_Case_Studies.pdf.

Con Edison – Brooklyn-Queens Demand Management (BQDM) Program

Background

The Brooklyn Queens Demand Management program (BQDM) can perhaps be considered the "big daddy" of non-wires alternatives projects with a distinctive distribution-focused DER component. Kicked off in 2014, it is one of the largest active NWA projects in the U.S., comprised of roughly 52 MW of traditional customer-side (41 MW) and non-traditional utility-side (11 MW) resources. The portfolio of technologies in the ongoing project is intended to lower demand in a targeted geographic area[8] and postpone the construction of a new distribution

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[8] The targeted areas in the BQDM program include neighborhoods in north-central and eastern Brooklyn, as well as southwestern Queens: Greenpoint, East Williamsburg, Bushwick, Bedford-Stuyvesant, Crown Heights, East Flatbush, Brownsville, East New York, Richmond Hill, Howard Beach, Broad Channel, Ozone Park, South Ozone Park, Woodhaven, and Kew Gardens.

substation and the expansion of an existing transmission switching substation (Brownsville No. 1 and No. 2) at least until 2026. Figure 3-5 depicts the BQDM's coverage.

The program specifically aims to address a forecasted overload condition of the electric sub-transmission feeders serving the BQDM area by reducing 69 MW of summer peaking load. The peak load-relief need occurs at night (9-10 pm), but the overload period runs 12 hours, from noon to midnight. (In addition to sourcing 52 MW of peak load reduction via NWA solutions, 17 MW in traditional utility infrastructure is helping to mitigate the peak load constraint.)

Figure 3-5
Geographic Boundaries of the BQDM Program

Source: Con Edison, 2018

Having received approval to implement the program from the NY Public Service Commission (NYPSC), Con Edison is now either currently enlisting or has plans to procure/incentivize a range of projects composed of fuel cells, combined heat and power (CHP), energy efficiency (mostly light bulb replacement), battery storage, solar PV systems, and conservation voltage optimization (CVO). These technologies – in addition to commercial, industrial, and residential demand response programs – are helping to relieve the stress on the utility's distribution system during periods of high demand and to generally improve system reliability.

Approach and Economic Considerations

The BQDM program is an outgrowth of New York's Reforming the Energy Vision (NY REV), the state's long-term energy strategy. As part of the NY REV, the NYPSC strongly encourages utilities to alter their planning processes by considering the procurement of needed equipment earlier (i.e. sooner than as a response to identified infrastructure upgrades) and "more broadly incorporate system design into NWA solutions." Con Edison management subsequently decided to forgo the traditional approach of addressing an identified sub-transmission feeder constraint with the build out of new grid infrastructure, by instead implementing a $200 million NWA program with the aim of deferring $1-1.2 billion of T&D investment.[9] The BQDM program has thus far principally sought load reductions for 2017 and 2018, but a program extension, discussed below, is refocusing load reduction efforts to beyond 2018.

Of the program's approved $200 million budget, approximately 75% ($150 million) is allocated to customer-side solutions, and the remaining 25% ($50 million) to utility-side approaches. All expenditures are treated as ten-year capital assets with a regulated rate of return (ROR) based on Con Edison's authorized weighted average cost of capital (WACC).[10] Meanwhile, a return on equity (ROE) adder of 100 basis points, effectively a bonus incentive, is tied to three performance metrics: peak-load reduction, DER provider diversity, and cost savings.[11]

Figure 3-6 illustrates Con Edison's benefit cost analysis (BCA) of the BQDM program (as of 2017). It depicts a comparison of the net present value of the revenue requirements necessary to cover the costs of both the wires alternative and the BQDM approach, including a suitable ROR on the rate-based expenditures and the costs avoided by the BQDM approach during the deferral period. The costs of the BQDM scenario initially exceed those of the wires alternative, but they ultimately fall below those of the wires alternative because the BQDM avoids $99.1 million worth of capacity, energy, distribution, environmental, and line loss costs. As a result, ratepayers are estimated to save $22 million based on BCA results.

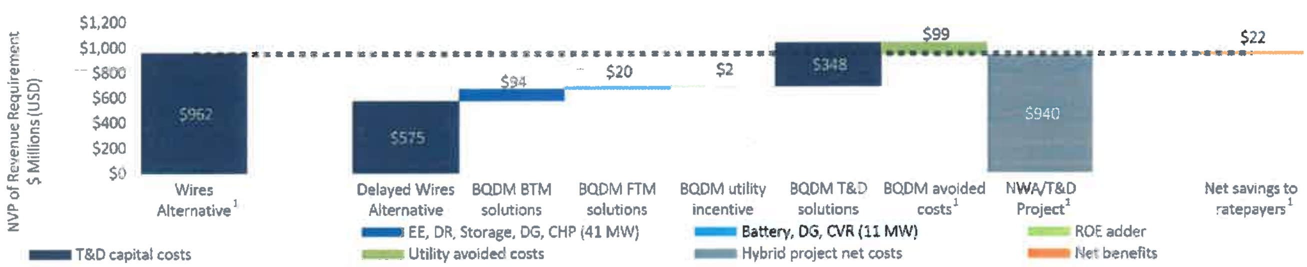

Figure 3-6
NPV comparison of revenue requirements between traditional wires alternative and BQDM program

Source: GTM Research, Q4 2016 BQDM Quarterly Report

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[9] This traditional approach would have entailed constructing a new area substation, establishing a new switching station, and building sub-transmission feeders by 2017.

[10] In other words, Con Edison is able to recover its BQDM program expenditures over a 10-year period while earning a return on the deferred costs at the ROR approved in its most recent electric rate proceeding.

[11] The ROE adder allows Con Edison to increase the base ROE utilized to calculate the project ROR. The utility will receive 45 basis points (bps) for achieving BTM peak-load reductions beyond the 41 MW proposed by Con Edison (i.e., 1 bp for each MW reduced beyond 21 MW); 25 bps to increase the diversity of DER providers in the service territory (i.e., 1 bp for each 0.01 increment beyond 0.75 in a normalized entropy index used to measure DER provider diversity); and 30 bps for reducing the unitary cost ($/MW) of the BQDM portfolio of solutions relative to the traditional T&D solution (i.e., 1 bp for each 1% reduction in cost relative to the $6 million/MW cost of the wires alternative).

To identify and procure the lowest-cost DER projects for the program, Con Edison administered a request for proposal process, overseen by the regulator.[12] The bulk of the BQDM's customer-side capacity has been acquired through third-party demand response aggregators via reverse auctions. Energy efficiency measures have also significantly contributed to the BQDM program's capacity, largely through the distribution of free lightbulbs and other lighting retrofit technologies. In this regard, new incentives have been successfully marketed via the utility's existing programs to make an immediate impact, and third-party relationships have subsequently been developed to expand offerings.[13]

The BQDM program has separately provided funding to aid in the uptake of CHP in the BQDM area. This funding has supplemented incentives offered by the New York State Energy Research and Development Authority (NYSERDA) under its CHP Acceleration Program. Together, the NYSERDA incentives, with matching funds from Con Edison, have offered potential to potentially cover 70–90% of a CHP project cost, with anticipated returns on investment of 1-3 years.[14] Solution providers have been incentivized to target their efforts in the BQDM areas with heightened requirements to help ensure load reduction. To drum up interest, NYSERDA, National Grid, and Con Edison also developed a joint marketing approach in the BQDM Area.

Fuel cells have also been implemented within the BQDM area to provide system benefit. Con Edison has engaged with customers and fuel cell vendors to evaluate the potential for using fuel cell technology to economically offset baseload consumption. All customers in the BQDM area with verified electric service account numbers have been eligible to participate. Site visits were conducted at select sites and customer bills analyzed to determine the feasibility of the technology's implementation. A partnership between Con Edison and a fuel cell vendor has also helped facilitate the adoption of fuel cells at eligible customer locations.

Con Edison has separately issued calls to contract for "shovel ready" battery storage projects targeting customer-side load reduction opportunities at commercial properties in the BQDM area. It initially received proposals from four respondents and, after review and evaluation of the proposals, communicated an incentive level that was intended to meet the hurdle rate ($/kW) needed to make the projects viable. Ultimately, one battery storage project was installed as part of a multi-technology installation at an affordable housing customer location, resulting in a 300-kW load reduction. Another 500-kW project, later lowered to 100 kW, was expected to provide additional load reduction, but was shelved due to a range of implementation, engineering, and regulatory challenges. Looking ahead, Con Edison plans to install a 12 MWh battery unit during the fourth quarter of 2018. The configuration will allow for a choice of discharge: either 1 MW for 12 hours, or 2 MW for 6 hours.

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[12] Con Edison issued a Request for Information (RFI) to seek proposals for customer- and utility-side non-traditional solutions for the BQDM Program. It used an RFI instead of a Request for Proposal (RFP) because it felt the former approach could solicit a broader array of responses, while providing greater insight into prevailing prices and the state of the marketplace.

[13] Marketing efforts included providing additional incentives beyond established amounts to target small businesses, multifamily, and commercial and industrial (C&I) customers.

[14] Eligible projects may receive an incentive of up to $1,800 per peak hour kW of load relief. Con Edison will provide a match up to the base incentive provided by NYSERDA, but will not match any bonus incentives that NYSERDA provides.

Con Edison has also implemented enhanced, efficient voltage control via CVO to reduce peak loads in the BQDM area. It separately explored pursuing a utility-side solar PV pilot that intended to leverage 1 MW of PV capacity from installations sited on the grounds of 10 unit substations and other buildings located in the BQDM Area. After review of submitted proposals, however, and pending additional load relief needs, the utility has put the project on hold.

Status and Next Steps

The BQDM program has been active since mid-2014 and was targeted to conclude at end-2018. However, Con Edison recently received an extension from the NYPSC to procure additional load-reducing NWA resources that will extend the program beyond its originally scheduled end date. Generally speaking, the program is considered a success and has met its primary objectives. As of Q2 2018, Con Edison had implemented roughly 40.8 MW of peak hour non-traditional utility side and customer-side solutions. Savings achieved through the program's portfolio of measures have delayed the buildout of a new substation beyond the initial load relief projections. To this end, roughly 6,700 small businesses, 1,660 multifamily buildings, and 21,500 family residences have participated in the program by taking part in energy efficiency and demand reduction measures, as well as other distributed generation initiatives.

Through the initial RFI process, Con Edison determined its portfolio approach could attract enough resources to manage both the BQDM area's peak load as well as the overall substation load profile. Energy efficiency and conservation voltage reduction measures have started out as the lead contributors, respectively delivering about 15 MW and 7 MW in savings during peak hours, as well as during non-peak times. Demand response programs have also been broadly effective. But base-load technologies, such as fuel cells and CHP, are beginning to deliver benefits too, collectively providing multiple MW's of peak-load reduction. Meanwhile, program incentives have supported the interconnection of several commercial scale solar PV systems. And other load relief is anticipated with the installation of energy storage. Table 3-2 summarizes the NWA opportunities that Con Edison has both pursued and tabled as part of the BQDM program. Meanwhile, Figure 3-7 shows the hourly load reduction provided by the different NWA resources leveraged as part of the BQDM program.

Table 3-2
Summary of BQDM program activity

NWA Opportunity	Status	NWA Opportunity	Status
Customer-side Solutions			
Commercial Direct Install	√	Multi-family Energy Efficiency	√
Residential Energy Efficiency Program(s)	√	Bring Your Own Thermostat Adder	√
Virtual Building Audits	√	New York City Housing Authority	√
Direct Customer Activity	√	Dynamic Resource Auction*	√
Fuel Cells	√	Queens Resiliency Microgrid	NP
City Agency Solutions	√	Commercial Refrigeration	√
Combined Heat and Power	√	Battery Storage	√
BQDM Extension Auction	√		
Utility-side Solutions			
Distributed Energy Storage Solution	√	Distributed Generation (DC-Link)	NP
Voltage Optimization	√	Solar PV Pilot	NP
Fuel Cell	NP		

Source: BQDM Quarterly Expenditures & Program Report, Q2 2018
*Notes: "NP" refers to efforts that Con Edison, based on evaluation and study, is no longer pursuing and does not expect to be a part of the BQDM Program portfolio of solutions. * "Dynamic Resource Auction" refers to market-driven approaches to procure DR-type resources with specific performance attributes.*

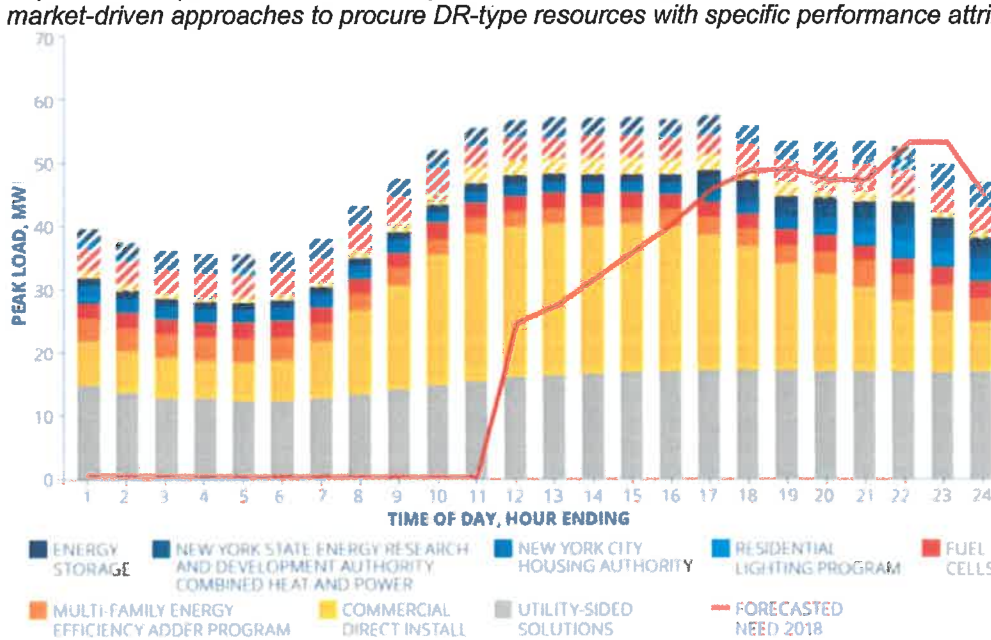

Figure 3-7
Example of hourly load reduction provided by different NWA resources in the BQDM program

Source: Con Edison, 2018

Lessons Learned

- **Regulatory policy is a primary impetus to NWA consideration and development.** The NY REV and consequent NYPSC rulings have provided the foundational motivation – through both carrots and sticks – to enable the BQDM program. Based on the NYPSC's guidance, state IOUs are formalizing the screening criteria they use to trigger the assessment of NWA solutions. Although the NYPSC is pushing utilities to incorporate more inclusive thresholds into their screening criteria, initial utility efforts to develop "suitability criteria" – including level and type of need, lead times, among others – are providing greater definition and, to an extent, transparency to NWA review and potential approval. Separately, as part of REV, the commission has approved two utility-proposed incentives designed to make the utility indifferent to implementing traditional, non-traditional, behind-the-meter, and front-of-the-meter mitigation solutions. These approaches – which include stipulations governing the utility's rate of return and a return on equity adder – have helped incent desired BDQM program outcomes.

- **Despite a helpful regulatory environment and supportive cost recovery rules, NWA-sponsoring utilities will likely encounter ongoing financial and non-financial risks.** Specific to the BQDM program, customer acquisition, vendor contracting, (battery) permitting, proper alignment of customer incentives and compensation structures, and municipal planning and coordination are some of the challenges that have thus far been identified. Con Edison is working to address these and other issues in future NWA planning efforts.

- **Requests for Information may be a better vehicle than Requests for Proposal to initially solicit responses.** Con Edison kicked of the BDQM program by issuing an RFI seeking proposals for customer- and utility-side non-traditional solutions for the initiative. The utility felt this approach could generate a broader array of responses, provide greater insight into prevailing prices and the state of the marketplace, as well as help shape future solicitations. For example, a fuel cell provider was able to leverage its RFI response and collaborate with Con Edison on a customer-sited fuel cell offering. Based on learnings from RFI responses, Con Edison also developed a proposal template to standardize proposal responses and allow for their more consistent evaluations.

- **Proactive engagement with customers and vendors has helped make the BQDM project a success.** Consistent communication between utility personnel and community stakeholders has supported a level of transparency and helped garner the project a positive public response. Meanwhile, vendor engagement has helped prompt BQDM participation and diversify the program's resource portfolio. Vendor interactions have also led to local economic development, with some local employers hiring new staff to fulfill projects in the BQDM area.

- **Planning DER deployments according to their respective lead times can help orchestrate a smoother implementation of technology portfolios.** Con Edison was able to incrementally build out BQDM program capacity reductions by initially pitching existing EE program offerings. As EE uptake ensued, it established demand response programming, and also pursued CHP, fuel cell, energy storage, and other distributed generation initiatives with longer development time frames. As a result, the utility was able to steadily bring capacity reductions online.

For More Information

- BQDM docket: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=14-E-0302.
- BQDM Quarterly Expenditures & Program Report, Q2 2018: file:///C:/Users/pnen001/Downloads/%7BC63D4E53-A72E-4D84-8CAB-9F2A5BC46E09%7D.pdf
- Brooklyn Queens Demand Management Program: Implementation and Outreach Plan: https://www.greentechmedia.com/articles/read/burning-questions-for-the-brooklyn-queens-demand-management-program.

National Grid – Little Compton Battery Storage Project

Background

The era of non-wires alternative projects in Rhode Island effectively began with the enactment of the 2006 Comprehensive Energy Conservation, Efficiency, and Affordability Act. The legislation establishes the Ocean State's "Least-Cost Procurement" policy which, among other things, requires electric distribution companies to strategically consider the deployment of cost effective customer- and utility-sited energy resources to meet system needs. Proposed within National Grid's annual System Reliability Procurement (SRP) Plans, these NWAs include energy efficiency, demand response, and distributed generation measures that principally aim to reduce peak loads while deferring or eliminating the need for new conventional supply (i.e. peaking generators) and/or traditional distribution (and potentially transmission) system upgrades.

The Narraganset Electric Company (d/b/a National Grid) has since either pursued or explored several NWA projects, including the recently concluded Tiverton NWA Pilot, a six-year customer-driven load curtailment effort that successfully deferred substation and feeder upgrades in the coastal towns of Little Compton and Tiverton though targeted energy efficiency and demand response measures.[15] To further delay a $2.9 million upgrade to the Tiverton Substation for another four years, the utility proposed pursuing the deployment of a 250 kW/1 MWh battery storage system to provide peak load relief through the summer of 2022. Known as the Little Compton Battery Storage Project (LCBS Project), this successor NWA initiative sought to demonstrate the feasibility of employing a battery solution to mitigate distribution grid constraints.

[15] In 2010, National Grid forecasted that two feeders serving Tiverton and Little Compton would be capacity-constrained during summer afternoon peak hours starting in 2014. The Tiverton NWA Pilot was launched in 2012 to reduce summer peak demand – driven by air conditioning, lighting, and other loads – by up to 1 MW by 2017, thus deferring substation upgrades to at least 2018. After five years of activity, the pilot was discontinued in December 2017 as planned.

Note: In December 2018, National Grid decided to cancel its proposed LCBS project (as well as its later iteration, the Tiverton-Little Compton NWA project) due to a reduced level of loading concern on the area's distribution infrastructure. It was determined that a downwardly adjusted peak load forecast as well as existing and in-queue distributed generation negated the need for the NWA project.

Approach and Economic Considerations

The LCBS Project was a latest attempt by National Grid to address peak load growth as well as distribution system reliability concerns through non-traditional approaches in the communities of Little Compton and Tiverton. Population growth in the two municipalities was nearly twice the state average, and the Tiverton Substation was already too small to support the area's approximately 5,200 customers (80% of which are residential, 20% commercial). Moreover, annual weather-adjusted summer peaks in Tiverton and Little Compton were expected to increase by an average of 0.3% and 0.1%, respectively, for the next 10 years—greater than the anticipated statewide average annual growth rate of -0.2%. (As noted above, a recalculated peak load forecast and identified distributed generation deployment capable of providing peak load relief have since altered the outlook for the area.)

The LCBS Project was intended to provide load relief in the same geographical footprint as the preceding Tiverton NWA Pilot. National Grid planned to enter into a four-year services contract with a 3rd party that would reduce peak load through a vendor-owned battery storage unit. (The vendor would be responsible for engineering, procuring, constructing, and installing the battery.) The 1-MWh storage solution, intended to be sited at Tiverton Public Works Facility, was to be charged from the electric grid and to provide 250 kW of continuous peak load relief for a four-hour period (3:30pm to 7:30pm) chiefly during the months of June through September. This peak load relief need was consistent with the forecasted load growth at the time for the Tiverton Substation.[16] When not being used for peak load relief, the battery was going to be able to participate in the ISO-NE energy market.

National Grid estimated project costs totaling $438,000, split evenly over the effort's four years. The utility had secured an initial $109,500 to implement the project in 2019, and proposed similar funding for each of the three years following (2020-2022). Of the budget amount allocated for 2019, $87,500 was associated with the actual implementation of the solution, including payments to the vendor for load reduction services and maintenance, while $22,000 was associated with vendor management (i.e. overseeing implementation of the system, its monitoring and evaluation). The project's costs were, meanwhile, to be paid for through National Grid's annual system reliability funding plan, which is funded by ratepayers through an Energy Efficiency Program (EEP) charge. (The charge adds roughly $0.01/kWh to Rhode Island customers' bills.)

Results from the utility's benefit-cost analysis confirmed the project's merits. Using the Rhode Island Test, an alternative to the Total Resource Cost (TRC) Test, it calculated that a four-year deferral would deliver $905,197 of localized distribution investment savings for its customers.

[16] National Grid estimates that, based on its current peak load forecast, four years is the maximum amount of time the Tiverton Substation upgrade can be deferred with a 1 MWh battery solution.

These benefits represented the amount of revenue requirement that would not need to be collected if the battery system was able to defer grid investments for four years. [17] [18] [19] Additional benefits were estimated assuming a continuous 250-kW peak load reduction over four hours for 20 days per year. (The 20 days per year estimate was based on the average number of days that demand response events were called in the Tiverton NW Pilot each year for 2015-2017.)

Table 3-3 provides an overview of the utility's benefit-cost analysis for the Tiverton-Little Compton NWA Project. With a positive BC Ratio of 2.29, National Grid determined the project to be a cost-effective approach to deferring grid upgrades.

Table 3-3
Little Compton Battery Storage Project Benefit-Cost Summary

Benefit and Cost Categories	Calculated Outcomes
Total Cost	$438,000 ($109,500 x 4 years)
Total Benefits	$1,004,816 ($905,197 in deferral value)
Net Benefits	$566,816
BC Ratio	2.29

Source: Rhode Island 2019 System Reliability Procurement Report

To verify initial estimates and promote learning, National Grid planned to evaluate the capacity demand savings produced by the NWA project through data provided via a metering and control system. Energy savings were to be calculated by measuring the amount of battery power output that is provided during peak periods throughout each calendar year.[20]

Status and Next Steps

National Grid had planned to re-bid the project, recast as the Tiverton-Little Compton NWA project, in the hopes of having an NWA solution installed by early 2019, in time for it to be operable by Summer 2019. It had previously completed an initial RFP solicitation in 2017 that resulted in the selection of a proposed lithium-ion battery storage solution. However, the project was eventually shelved due to, among other things, delays in construction scheduling and equipment availability, which lowered the selected vendor's assessment of the project's value proposition.

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[17] The revenue requirement is the amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest paid on debts owed to investors and, if applicable, a reasonable return.

[18] The Tiverton Substation upgrade was originally planned for 2014, so all project benefits were inflated to $2019 to match the proposed NWA Project budget.

[19] The Rhode Island Test is primarily used to more fully account for the costs and benefits of energy efficiency proposals. It is also applied to evaluate non-wires alternatives projects. The calculated deferral of localized distribution investment savings generated by the TLC NWA battery was inserted into the RI Test model as a replacement for the regional distribution benefit in the avoided costs calculated for energy efficiency measures.

[20] The expectation was that the battery would charge during lower wholesale price periods and discharge at higher wholesale priced hours, with the "savings" being the difference in these prices.

In December 2018, National Grid determined that an NWA solution for the Tiverton-Little Compton area was no longer needed due to a downwardly adjusted peak load forecast and the presence of enough distributed generation to help reduce potential grid constraints. However, the utility intends to continue examining additional opportunities to defer investment upgrades for other undersized substations in Rhode Island.

Lessons Learned

- **Develop a risk mitigation strategy for NWAs** to avoid circumstances in which delays and equipment availability may derail projects.
- **Be flexible in load growth forecasts.** Anticipated load growth at a substation may not materialize or it alternatively may accelerate. These outcomes will impact the economics of a NWA deferral project.
- **Measure capacity demand savings to verify initial estimates and promote learning.** National Grid's aim to evaluate the capacity demand savings produced by the LCBS Project through data provided via a metering and control system was intended to promote learning as well as potentially prove out the efficacy of leveraging battery storage to reduce peak load.
- **Consider the tradeoffs of pursuing a third-party services contract versus development of utility-owned project.** National Grid planned to enter into a battery services contract with a 3rd party to reduce peak load. This approach has inherent risks and benefits (e.g. potential for vendor bankruptcy, but also lower costs and reduce utility burden).

For More Information

- 2019 Rhode Island System Reliability Procurement (SRP) Report: http://rieermc.ri.gov/wp-content/uploads/2018/09/2019-srp-report-final-draft.pdf.
- 2018 Rhode Island System Reliability Procurement (SRP) Report: http://www.ripuc.org/eventsactions/docket/4756-NGrid-SRP2018_11-1-17.pdf.
- Overview of the Rhode Island Test: http://www.ripuc.org/eventsactions/docket/4684-NGrid-RITest-Tech%20Session(9-13-17).pdf

4
CONCLUSIONS AND KEY TAKEAWAYS

A non-wires alternative is defined as a utility-driven solution to an identified distribution constraint that defers or eliminates the need for a traditional distribution upgrade. Historically comprised of demand-side management measures that have been employed by utilities for decades, NWAs are now beginning to incorporate energy-exporting DERs, like PV and battery storage, largely as a result of falling technology costs and supportive regulatory directives. These often first-of-their-kind projects are seeking to provide flexibility in deployment (i.e. via incremental implementation); reliability at lower cost relative to traditional wires alternatives; and experiential learning on a range of novel operational, technology, and business model strategies

A critical aspect of an NWA is that the solution be the result of the utility's obligation to serve its customers. For example, DERs that materialize organically and offset the need for a conventional upgrade should not be considered non-wires alternatives; rather, they represent inputs that will change the utility expansion plan. From a distribution planning standpoint, grid connected DERs can be viewed along a spectrum with two overarching perspectives:

1. as resources that may require mitigation and need to be accommodated at the distribution level, or
2. as resources that can be integrated into the distribution system as alternative solutions to traditional distribution upgrades.

Regardless of whether DERs are being accommodated or integrated, they must be included in the overall distribution planning process. That said, distributed energy resources present a unique opportunity for distribution planners to provide innovative and potentially more tailored alternatives to traditional distribution upgrades. However, NWAs may not be directly comparable to traditional solutions, and will likely require additional technical and economic considerations to ensure that reliability of service is maintained. These considerations can be split into four overarching categories:

- *Locational considerations*: Those involving spatial and siting limitations, the location of the constraint, and feeder siting.
- *Temporal considerations*: Those concerning resource availability, output variability, sustainability of response, and resource lifetime.
- *Additional design considerations*: Those encompassing the sizing of NWAs, alternative lead-times, reliability, customer participation, and third-party contractual arrangements.
- *Economic considerations*: Those regarding the costs and benefits associated with pursuing NWA projects given DER performance and lifetime considerations in the context of the regulatory/policy landscape.

The factors to consider for DER as a non-wires alternative are further enumerated in Table 4-1.

Table 4-1
Summary of factors to consider for DER as a non-wires alternative

Category	Factor to Consider	Notes
Location	Geographic	Resource availability
	Grid placement - direction of constraint	Related to nature of constraint, voltage thermal etc.
	Grid placement - proximity to constraint	Important for networked systems
	Alternate configurations	Switching schedules, contingencies
	Hosting capacity	Related to temporal factors
	Space availability	Related to physical sizing factors
	Siting issues	Safety and other restrictions
Temporal	Constraint/output coincidence - instant in time	Time of day - how does the DER output and distribution constraint coincide?
	Constraint/output coincidence - day of year	Day or season - how does the DER output and distribution constraint coincide?
	Sustainability	Duration of output from DER
	Lifetime	Short- vs long-term lifetime. Related to degradation and cycling
	Lead times	Short- vs long-term lead time. Length of procurement process. Forecasting uncertainty
	Charge/discharge times	Related to sizing
	Flexibility	Related to variability and portfolio design
	Controllability	Related to variability and portfolio design
	Resource variability	Related to fuel source
Design *Sizing*	Power	Related to other temporal, location and dispatchability factors
	Energy	Related to other temporal, location and dispatchability factors
	Losses/efficiency	Related to location factors
	Headroom	Related to forecasting uncertainty
	Customer participation	For EE and DR, type and number of customers
	Degradation	Related to temporal factors
Design *Reliability*	Lifetime	Related to degradation, cycling and forecast uncertainty
	Availability	Number of resources, many small or one large
	Probability of failure	Number of critical systems (e.g. resource, power electronics, communications) and their probability
Design *Other*	Third party contracting	Lead time for contracting, risk of going out of business, etc.
	Portfolio design	Desired objective and optimal resource share
Economics	Capital Costs	Related to lead times (upward and downward trend)
	Operational Costs	Fuel costs
	Maintenance Costs	Related to lifetime
	Lifetime and replacement costs	Related to planning horizon
	Avoided costs	Energy, ancillary services, RPS, taxes, etc.

It should be noted that although the number of considerations to be made are substantial, not all factors will be applicable to all NWAs. Additionally, for some factors, there is still much to be learned in order to compare NWAs with conventional distribution upgrades on a like basis. To consider DERs and NWAs as part of the distribution planning process, the overall steps of the existing planning process do not need to change, but the outlined factors will need to become additional considerations within each planning step. This will facilitate fair and consistent comparisons of all available mitigation alternatives.

Key Case Study Observations

To provide industry guidance on the future development of successful NWA arrangements, EPRI profiled three real-world NWA projects—two existing, and one proposed. The case studies highlight each project's locational, temporal, design, and economic considerations in an effort to illustrate their influence on chosen approaches and associated outcomes.

In many ways, all three NWA initiatives – Arizona Public Service's Punkin Center project, Con Edison's BQDM program, and National Grid's proposed Little Compton Battery Storage Project – are each serving as a testing ground for novel technologies, programs, and methods that can deliver distribution system benefits. They are leveraging a growing body of DER operations and maintenance experience to pursue a variety of use cases, and, in turn, helping to evolve traditional utility planning and business models for grid integrating rising penetrations of variable resources, accommodating forecasted load growth, and mitigating associated distribution system constraints.

What follows are observations across the described NWA projects. Reflections are meant to compare and contrast the primary considerations driving each of the projects and convey commonalities and differences that can help mainstream successful utility NWA initiatives.

Locational Considerations

All three NWA initiatives take into account the locations of identified system constraints, and consider potential spatial and siting limitations that may impact the applicability and effectiveness of certain non-traditional mitigating solutions.

- The battery solution at the APS Punkin Center project is sited 16.5 miles downstream of the feeder constraint and can be appropriately dispatched through several methods to mitigate thermal issues, as necessary. The installation has no spatial limitations; it, in fact, has been planned with expansion in mind should load growth require it.
- ConEdison's BQDM program employs a portfolio of DERs to provide targeted load reductions in an urban environment. Utility- and customer-sided installations and schemes, dispersed throughout the project's boundary area, collectively alleviate substation constraints. The multiple and complementary solutions employed overcome siting limitations in a city environment.
- The proposed 250 kW/1 MWh battery installation in National Grid's LCBS project was intended to provide peak load relief through the summer of 2022. The system was going to be located on municipal land to address forecasted load growth at the nearby Tiverton Substation.

Temporal Considerations

Resource availability, output variability, sustainability of response, and resource lifetime are incorporated into the strategies of each of the NWA projects.

- The 2 MW/8 MWh battery at Punkin Center is sized to effectively address thermal constraints on the feeder during 20 to 30 peak power demand days per year. Battery dispatch can occur through three methods and is now coordinated with integrated volt/var control to manage feeder voltage during reverse power flow conditions.
- BQDM's portfolio of customer-sited and utility-owned DERs are designed to complement each other and provide summertime overload relief for a period of 12 hours, from noon to midnight, including the peak load constraint that occurs from 9-10pm.
- The LCBS project's planned battery installation was an extension of a previous NWA that relied on energy efficiency, demand response, and solar PV measures. Stakeholders determined that the battery, given load growth projections, was capable of meeting anticipated grid constraints for a needed four-hour period during the summer months.

Additional Design Considerations

The profiled projects have different requirements related to their sizing, lead-times, reliability, customer participation, and third-party contractual arrangements. BQDM comprises a portfolio of technologies, while the others contain a singular solution type. BQDM relies on behind-the-meter customer installations, while the others employ front-of-the-meter utility arrangements. Meanwhile, BQDM and Punkin Center are further along in their lifecycle, and have generated the kind of operating data and experiential learning useful to facilitating industry education.

- A competitive bidding process was successfully used by APS to procure, own, and operate the Punkin Center battery storage unit. A long-term ten-year contract with a developer assures the batteries run at nameplate capacity. Meanwhile, redundancy has been baked into communications infrastructure to assure constant connection with the battery system. Flexibility has also been incorporated into the site, and contingency generators are on call in the event of a battery outage.
- BQDM is pursuing a portfolio of customer- and utility-side NWA measures to defer traditional wires upgrade. The employed technologies are intended to complement one another to meet project objectives. However, customer acquisition, vendor contracting, (battery) permitting, proper alignment of customer incentives and compensation structures, as well as municipal planning and coordination have introduced challenges.
- National Grid planned to enter into a four-year services contract with a third party that would reduce peak load through a vendor-owned battery storage unit at its Tiverton NWA pilot. An accepted bid for the project was eventually shelved due to, among other things, delays in construction scheduling and equipment availability, which lowered the selected vendor's assessment of the project's value proposition.

Economic Considerations

The three profiled projects are either pilot projects or are mandated by regulatory or legislative bodies. Moreover, the economics driving existing projects appear to pencil out, with benefits outweighing costs over their expected operating lifecycles.

- The Punkin Center Battery Storage Project is oversized compared to the projected T&D deferral need so it can generate savings through energy arbitrage and other grid services such as solar peak shifting, voltage regulation, and power factor regulation. The remote location of the Punkin Center community as well as its growing load demands, the challenges introduced by the surrounding area's rugged terrain, and the battery system's added technological benefits (i.e. value streams) were key to the project's greenlighting.
- The BQDM program is an outgrowth of New York's long-term Reforming the Energy Vision strategy and has leveraged incentives offered by NYSERDA and others to promote program participation. Moreover, the utility is taking advantage of favorable cost recovery terms as well as a return on equity adder that is tied to several performance metrics (peak-load reduction, DER provider diversity, and cost savings). The costs of the BQDM scenario exceed those of the wires alternative, but once savings from avoided capacity, energy, distribution, environmental, and line loss costs are factored in, the project results in a net savings to ratepayers.
- The LCBS project's costs were going to be paid for through National Grid's annual system reliability funding plan, which is funded by ratepayers through an Energy Efficiency Program (EEP) charge. National Grid's benefit-cost analysis using the Rhode Island Test, an alternative to the Total Resource Test, calculated that a four-year deferral would deliver savings for its customers.

5
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A
REPRESENTATIVE NWA PROJECTS WITH ENERGY-EXPORTING DER

Non-wires alternatives projects are steadily gaining traction as DER costs continue to fall, and technology operations and maintenance experience progressively accrues. Regulatory mandates along with supportive incentive schemes are also helping to stimulate development. Collectively, these overarching drivers are catalyzing novel NWA initiatives that primarily aim to produce distribution system benefits, like infrastructure upgrade deferral, via a range of use cases. Moreover, many of these trailblazing efforts are departing from historical approaches that exclusively apply energy efficiency measures and demand response schemes. Instead, they are leveraging energy-exporting resources – such as solar PV, fuel cells, CHP, wind, and energy storage – to achieve both short- and longer-term objectives.

Table A-1 provides a representative list of these emerging NWA projects, including key details about each project's utility sponsor, size (kW and/or kWh), technology composition, location and status, and background. As shown, the project group includes a diversity of DERs and approaches. Some comprise a portfolio of technologies, while others contain a singular solution type. Some rely on behind-the-meter customer installations, while others employ front-of-the-meter utility arrangements. Meanwhile, some are further along in their lifecycle than others, and have generated the kind of operating data and experiential learning useful to facilitating industry learning. Though still relatively small in number, these newer, often experimental, NWA initiatives are helping to inspire like-minded projects each with a unique set of location, temporal, design, and economic considerations.

Table A-1
Representative NWA projects that employ energy-exporting DERs

Utility - Project Name	Technology / Size	Location / Status	Summary Details
Arizona Public Service – Punkin Center	ES: 2MW / 8MWh	Arizona / Launched 1Q18	Battery system addressing load growth and resulting thermal constraints on a rural feeder by providing peak shaving during 20-30 peak power demand days per year. Other grid services also available via the unit (solar shifting, voltage regulation, etc.) Upshot: upgrade deferral of 16.5 miles of T&D infrastructure over rough terrain. Redundancy and design flexibility incorporated to ensure reliability, add battery capacity to meet future load growth.
Central Main Power (Avangrid) – BoothBay Pilot Project	EE, DR, PV, ES, diesel gen: 1.85 MW	Maine / Launched: 4Q13, Completed: 2Q18	Utility worked with 3rd party provider GridSolar to develop/operate DG, EE, DR to avoid $18M Tx line rebuild to the Boothbay region (primarily thru load reduction). Battery and thermal energy storage technologies deployed in 2013-2015, along with a diesel-fueled back-up generator, EE commercial lighting, and rooftop PV. Project terminated due to lower than expected electric load growth. Project costs totaled $6M, saving ratepayers ~$12M (present value terms) in avoided stranded costs from an unneeded Tx project alternative.
Con Edison – Brooklyn-Queens Demand Management (BQDM) Program	DR, EE, PV, ES, FC, CHP, CVR: 52MW	New York / Launched 2014	BQDM employing $200M in contracts for DER, DR, and other load relieving solutions to overcome a sub-Tx feeder constraint thereby delaying construction of a $1.2B area substation, new switching station, and feeders. To date, EE programs have yielded 15 MW in peak load reductions; DR has also made significant capacity contributions; fuel cells and CHP have offered 8 MW of deliverable peak load reduction capacity. Other load relief anticipated from energy storage. Program recently extended by NYPSC.
National Grid – Little Compton Battery Storage Project	ES: 1 MW / 250 kWh	Rhode Island / In Development	To delay a $2.9 million substation upgrade, the utility proposed procuring services from a 250 kW/1 MWh, vendor-owned battery storage system to provide peak load relief through the summer of 2022. The battery was intended to predominately be used to reduce peak from 3:30pm to 7:30pm during June thru September. When not being used for peak load relief, the system was going to be allowed to participate in the ISO-NE energy market. Due to a downwardly adjusted peak load forecast and the presence of significant distributed generation able to help reduce potential grid constraints, the project was no longer deemed necessary and shelved in December 2018.
National Grid – Old Forge	ES: 19.8MW / 63.1 MWh	New York / In Development	Microgrid project seeks to improve the reliability on a radial, 46 kV sub-Tx line that feeds 5 substations in 3 New York counties by sectionalizing a fault and serving impacted customers during an outage. The effort presents an opportunity to improve the CAIDI and SAIFI reliability scores for the 7,700 residential and commercial customers in the area. An RFP issued in 2017 generated 9 proposals, nearly all of them containing energy storage. RFP award expected in 1Q19.
National Grid – Nantucket Battery Storage Project	ES, diesel gen: 6 MW/48 MWh and 10 MW	Massachusetts / In Development	Utility procuring a Tesla battery, to be installed by 2019, in order to delay the construction of a third undersea transmission cable to meet increasing summer peak demand. (Peak demand is double the load experienced during non-summer months.) The battery is expected to defer the construction of the undersea cable (price tag: $75M-100M) by 15-20 years, or 3-8 years beyond the current forecast. Two existing 3-MW diesel generators will also be replaced by a 10-MW unit for emergency back-up.

Utility - Project Name	Technology / Size	Location / Status	Summary Details
Pacific Gas & Electric – Angel Island	PV, Wind, NG, ES: TBD	California / unclear	Originally pursued as a demo (E) project under the utility's distributed resources plan (DRP), the NWA seeks to replace 2 undersea 12 kV cables serving Angel Island. Preliminary study proposed 2 NWAs comprised of wind, PV, battery storage, and propane/natural gas back-up. DER technology make-up still TBD. The solicitation seeks bids from a variety of front- and behind-the meter DER technologies.
Pacific Gas & Electric – Chowchilla, El Nido Substation (Demo Project C)	DER: TBD	California / In Development	Part of PG&E's distribution resources plan (DRP), project seeks 4 MW of distribution baseload capacity by summer 2019 or 2020, and 1 MW of distribution peak capacity by April 2019 or 2020 to demonstrate DER's locational benefits to provide Dx capacity services for mitigating overload.
Pacific Gas & Electric – Oakland Clean Energy Initiative	ES, EE: 45 MW	California / In Development	Approved by CA regulators in March 2018, PG&E and local electricity supplier East Bay Community Energy will use DER to replace an outdated fossil fuel peaker plant and serve Tx reliability needs. Projected NWA cost is $102M vs. $537M in new Tx infrastructure.
Southern California Edison – Distributed Energy Storage Integration (DESI) Pilot 1	ES: 2.4 MW / 3.9 MWh	California / Launched 2015	A utility-side Li-ion battery from NEC Solutions (procured thru a competitive bidding process) is deferring upgrades to a 12 kV distribution circuit and increasing reliability by providing load management services to support summertime peaks. In addition to limiting load, the system can simultaneously support circuit voltage or control reactive power flow at the substation. It is a dedicated, single-point grid reliability device rather than a dual-use system (i.e. one that can also participate in the CAISO market when not being used for reliability). The battery, located in a compact customer location, is maintained by a 3rd party and owned/operated by the utility as a grid asset.
Southern California Edison – Distributed Energy Storage Virtual Power Plant	ES: 85 MW	California / Launched 2016	Utility partnering with 3rd party provider Stem to deploy customer-sited energy storage that can contribute flexible capacity over 10 years. The project is part of the utility's effort to meet its long-term local capacity requirements (LCRs) by 2021, which have been exacerbated by the closure of the San Onofre Nuclear Generating Station and anticipated NG retirements in Southern California. It leverages Stem's AI platform to control and dispatch a virtual power plant (VPP) of distributed resources on a repeatable, real-time, day-ahead and targeted geographic basis. As a result, the VPP serves as a firm, on-call dispatchable, peak capacity resource that applies storage systems as demand response. >100 systems currently participating, with more in the construction phase. Customer contracts include fixed monthly subscription payments; the utility hopes avoided cost savings will exceed payments by 2-3x.

Sources: SEPA, PLMA, GTMR, EPRI

Note: CVR = Conservation Voltage Reduction; CHP = Combined Heat & Power; DR = Demand Response; EE = Energy Efficiency; ES = Energy Storage; NG = Natural Gas; PV = Photovoltaics

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Screening of Non-Wires Alternatives in Distribution Planning

Guidance, Criteria, and Current Practices

3002018820

Screening of Non-Wires Alternatives in Distribution Planning

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Technical Update, December 2020

EPRI Project Manager

J. Taylor

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ABSTRACT

Non-wires alternatives (NWAs) undoubtedly add more complexity to the distribution planning process, due to the significant time and effort associated with detailed NWA identification and evaluation. NWA screening criteria and methods can provide a means of simplifying the integration of NWAs into distribution planning by determining at various stages of the planning process, whether it is sensible to proceed with a more detailed assessment of an NWA solution. The objective of this report is to make it easier to consider NWAs within the distribution planning process by identifying criteria, methods, and practices for efficient screening of NWA projects based on economic suitability and technical feasibility. To this end, this report: 1) Documents current industry practices and considerations on NWA screening in various jurisdictions in the U.S. and Europe; 2) Presents around 20 technical, economic, reliability and other NWA screening criteria and methods; and, 3) Provides guidance on the application of NWA screening within distribution planning. The research described in this report is the beginning of a multi-year effort examining screening of NWAs.

Keywords
Non-wires alternatives
Distribution planning
Solar photovoltaics
Energy storage
Demand response

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EXECUTIVE SUMMARY

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PRIMARY AUDIENCE: Distribution system planners and utility resource planners

SECONDARY AUDIENCE: Industry stakeholders interested in the application of non-wires alternatives

KEY RESEARCH QUESTION

There is increasing interest in non-wires alternatives (NWA), i.e., solutions to distribution constraints that can defer, mitigate, or eliminate the installation or upgrading of existing distribution assets. Detailed evaluation of NWAs introduces additional and potentially complex considerations and analytics to the distribution planning process that can require significant planning resource time. NWA screening criteria and methods can provide a means of simplifying the integration of NWAs into distribution planning by determining at various stages of the planning process, whether it is sensible to proceed with a more detailed assessment of an NWA solution. However, as NWA evaluation processes are still evolving, guidance is needed on NWA screening criteria and methods, and their application in the various stages of the planning process.

RESEARCH OVERVIEW

This report identifies criteria, methods, and practices for efficient screening of NWA projects. Current industry practices and considerations on NWA screening in various jurisdictions in the U.S. and Europe are reviewed, compared, and documented. This report also presents around 20 technical, economic, reliability, and other NWA screening criteria and methods that are built on industry best practices on NWA screening. Guidance on the application of NWA screening within the various stages of the distribution planning process is provided. Finally, areas for future research are identified and documented.

KEY FINDINGS

- NWA screening criteria and methods can provide a means of simplifying the integration of NWAs into distribution planning by determining at various stages of the planning process, whether it is sensible to proceed with a more detailed assessment of an NWA solution.
- Various NWA screening criteria and methods can be applied before and within the individual stages of the distribution planning process.
- NWA screening criteria, methods, and practices in different jurisdictions in the U.S. and Europe are reviewed.
- Approximately 20 technical, economic, reliability and other NWA screening criteria and methods, which build on industry best practices, are presented.

WHY THIS MATTERS

Non-wires alternatives represent a new tool in the planner's toolkit. However, non-wires alternatives introduce additional and potentially complex considerations and analytics within the distribution planning process that can require significant planning resource time. By efficient utilization of screening criteria and methods, planners will be able to more efficiently evaluate non-wires alternatives as solutions to distribution constraints.

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EXECUTIVE SUMMARY

HOW TO APPLY RESULTS

The screening criteria and methods presented in this report can be integrated as part of the planning process. Guidance is provided on considerations and application of the different screening criteria and methods.

LEARNING AND ENGAGEMENT OPPORTUNITIES

The research described in this report is the beginning of a multi-year effort examining screening of NWAs within the EPRI Distribution Operations and Planning (P200) program. Several areas for future research are identified in this report. Different research programs at EPRI have been advancing the utility industry's awareness of NWAs for many years. EPRI has an increasing body of research informing utilities and other stakeholders on the various facets of NWAs in distribution planning. More details on research to date can be found in the technical brief *Integrating Non-Wires Alternatives into Utility Planning: 2020 EPRI Research Guide* (EPRI report 3002018655).

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PROGRAM: Distribution Operations and Planning (P200)

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1
INTRODUCTION

Background and Motivation

Distribution utilities, regulators, and other stakeholders are showing increasing interest in considering *non-wires alternatives* (NWA)[1], which are solutions to distribution constraints that can defer, mitigate, or eliminate the installation or upgrading of existing distribution assets such as transformers and lines. In a poll conducted by EPRI in May 2020, roughly 75% of the 23 participating North American distribution utilities responded that they are encouraged to consider NWAs by their regulator[2] indicating the growing interest to NWAs in the industry.

The definition of NWAs encompasses distributed energy resources (DER), such as PV and storage, as well as increased control and schemes, such as demand response and energy efficiency. While NWAs can be considered for transmission system applications as well, this report focuses on NWAs utilized for distribution applications. At the distribution level, NWAs are being proposed as alternative solutions for providing additional capacity, improving reliability, and supporting voltage regulation, among other applications[3]. In the recent EPRI poll mentioned above, capacity deferral and reliability were the most common NWA applications considered by the responding distribution utilities.

The concept of *grid services*[4] is sometimes associated with DER-based NWAs. Distribution services, in particular, refers to the DER power imports and/or exports required to address specific distribution system constraints. Examples of distribution services include capacity deferral and voltage support. Requirements for successful service delivery can be characterized technically based on distribution needs. Any given distribution-level NWA opportunity may require the provision of one or several distribution services.

Detailed evaluation of NWAs introduces additional and potentially complex considerations and analytics within the distribution planning process that can require significant planning resource time, see [1] – [4]. Figure 1-1 illustrates some of the factors to consider when assessing NWA opportunities.

---

[1] Non-wires alternatives are sometimes referred to as non-wires solutions (NWS).

[2] As the poll surveyed only a small subset of North American distribution utilities, the responses may not be indicative of the broader state of the industry.

[3] NWA distribution applications are also sometimes referred to as distribution services. It may be possible to utilize a NWA solution for more than one distribution application/service along with so-called stacked services not related to the distribution system.

[4] The term *flexibility services* is also used.

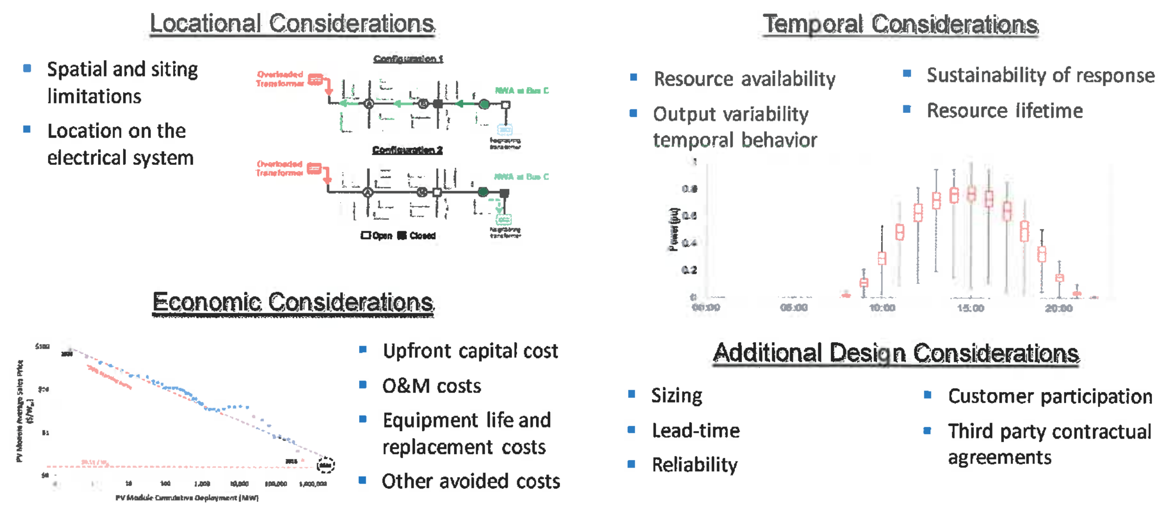

Figure 1-1
Factors to consider when assessing NWA opportunities [1]

It may not always be necessary to perform a detailed NWA evaluation. Various NWA screening criteria and methods can be applied to determine whether the feasibility of NWA solutions warrant continuing to the subsequent step in the planning process. However, as NWA evaluation processes are still evolving, NWA screening analysis criteria and methods are also in the early development stage.

To illustrate this point, in the recent EPRI poll mentioned above, just over 33% of the responding distribution utilities had established an NWA evaluation process and only 25% had developed NWA screening or prioritization criteria or methods. This is notably less than the 75% of the respondents who are currently encouraged to consider NWAs by their regulator or are already considering NWAs. There is a clear need for NWA evaluation processes, as well as for NWA screening criteria and methods.

Figure 1-2 shows the most important considerations and gaps in NWA screening, as identified by the respondents of the EPRI poll introduced above. As expected, economic screening was selected as a dominant NWA screening consideration by most respondents, followed by technical and reliability screening considerations. Among other things, the poll respondents highlighted the need for improved NWA economic evaluation methods to factor in various complexities such as NWA decommissioning costs, variable interest rates, future cost of energy storage systems, etc. The respondents also highlighted the need to consider the reliability implications of renewable-based NWA solutions and the potential associated energy storage requirements. As shown in Figure 1-2, the respondents indicated gaps across all aspects of NWA screening, including tools, criteria, data, processes, and methods. The respondents also highlighted the challenges associated with assessing third-party NWA solutions (more complex than utility NWAs) and considering NWA market participation (which markets NWAs can participate in, when, and how).

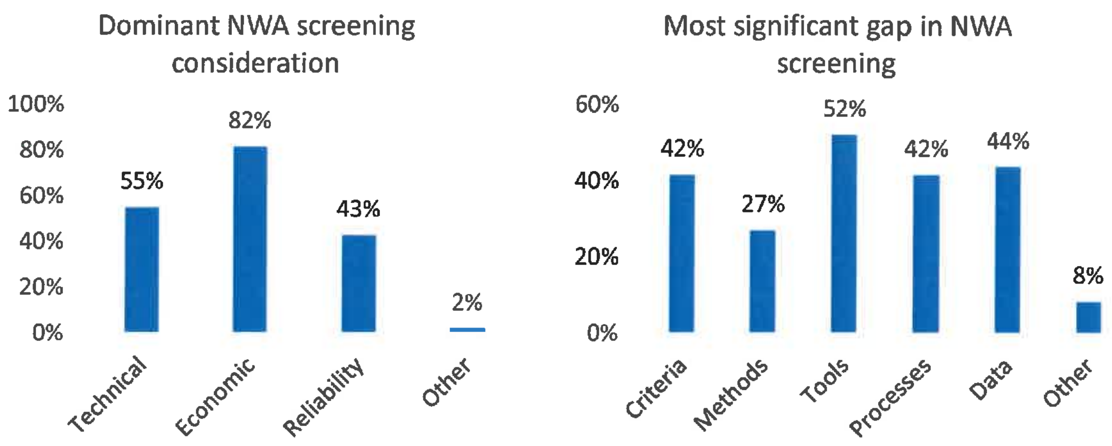

Figure 1-2
EPRI utility poll responses on the most significant considerations and gaps in NWA screening

Report Scope

This report builds on EPRI's past research on integrating DER and NWA within distribution planning. EPRI has completed a wide range of research related various aspects of NWAs, see Figure 1-3 summarizing selected past EPRI reports. A more comprehensive guide to EPRI research on integrating NWAs into utility planning is provided in [5]. Key topics explored to date include but are not limited to:

- Influence of time & location on DER value
- DER sizing
- DER reliability & lifetime estimates
- Cost-benefit analysis methods
- Integrating energy storage as a NWA in distribution planning
- Comparing multiple DER-based solutions
- Working with 3rd parties
- DER technologies including energy storage, PV and demand response.

Examining the Effects of Storage as Mitigation to Distributed PV Impacts on Distribution (3002008212)

Time and Locational Value of DER: Methods and Applications (3002008410)

Comparing the Cost-Benefit of Guided vs. Unguided PV Deployment on Distribution (3002008213)

A Systematic Framework for Analyzing DER and Energy Storage (3002010272)

Guidance on DER as NWAs (3002013327)

Incorporating DER Into Distribution Planning (3002010997)

Quantifying the Locational Value of DERs (3002015284)

Outsourcing NWAs to 3rd Party Providers (3002015767)

Guidance on Integrating Energy Storage into Distribution Planning: Using Energy Storage as a NWA for Distribution Capacity (3002015232)

Method for Optimizing Traditional and NWAs Across A Multi-Year Planning Horizon (3002015278)

Reliability and Lifetime Estimates of DER-based Planning Alternatives: PV Systems, Energy Storage, and Inverters (3002015230)

Figure 1-3
EPRI's NWA research to date

The objective of this report is to make it easier to consider NWAs within distribution planning process by identifying criteria, methods, and practices for efficient screening of NWA projects based on economic suitability and technical feasibility. To this end, this report:

- Documents current industry practices and considerations on NWA screening,
- Provides guidance on including NWA screening within planning steps, and
- Derives novel screening criteria and methods and provides guidance on their application.

This report focuses mainly on PV, battery energy storage systems (BESS), and demand response (DR), which are the most common NWA resource types considered. This report further focuses mainly on distribution capacity and reliability, which are most commonly considered NWA applications. Other NWA resource types and applications are discussed to some extent.

The Role of NWA Screening in Distribution Planning

Evaluating non-wires alternatives involves additional and potentially complex considerations and analytics within the conventional distribution planning process that can require significant planning resource time, see [1] – [4]. Effective use of NWA screening criteria/methods can help to streamline the use of distribution planning resources through:

- Saving valuable engineering time when designing & evaluating NWA,
- Determining more rapidly the feasibility and viability of NWA solutions, and
- Integrating DER effectively into future resource plans.

Different types of NWA screening can take place in between the various steps of the distribution planning process as illustrated in Figure 1-4. The screening objective between each step is to identify whether it makes sense to continue considering NWA solutions in the subsequent steps of the planning process. Chapter 2 reviews the NWA evaluation processes developed in some jurisdictions in the U.S., including the types of NWA screening that are applied at the different stages of the process. The mapping of the different NWA screening types within the planning process is further discussed as the screening types are discussed in Chapters 3-6.

As techno-economically attractive NWA opportunities are currently rare, it likely makes sense to first identify the traditional ("wires") solution(s), including a cost estimate, before considering NWA solutions. This may change in the future as NWAs become more competitive and common. In the future, it may make sense under some circumstances to consider NWAs first, and screen for the traditional solution(s).

In some circumstances, it may make sense to evaluate a distribution need during multiple distribution planning cycles following the process illustrated in Figure 1-4. For example, a distribution need identified in a given distribution planning cycle may be too far in the future and/or too uncertain to warrant either a traditional or a NWA solution in the given planning cycle, and it may be preferable to monitor and re-evaluate the distribution need in subsequent planning cycles. As the distribution needs, solution costs, and many other parameters evolve over time, it may also make sense to re-evaluate NWA solutions for distribution needs for which traditional solutions were identified in earlier planning cycles, provided that sufficient lead time to deploy NWA solution is still available.

Some aspects that are not discussed in detail in this report, but will be explored in future work, relate to different flavors of NWA screening depending on the overall NWA evaluation and procurement processes, for example:

- Screening of different NWA types, e.g., DER solutions vs. programs vs. pricing schemes
- Screening of utility vs. third-party NWAs
- Screening of NWAs employing a single DER vs. combinations of (or combinations of DER, programs and pricing schemes).

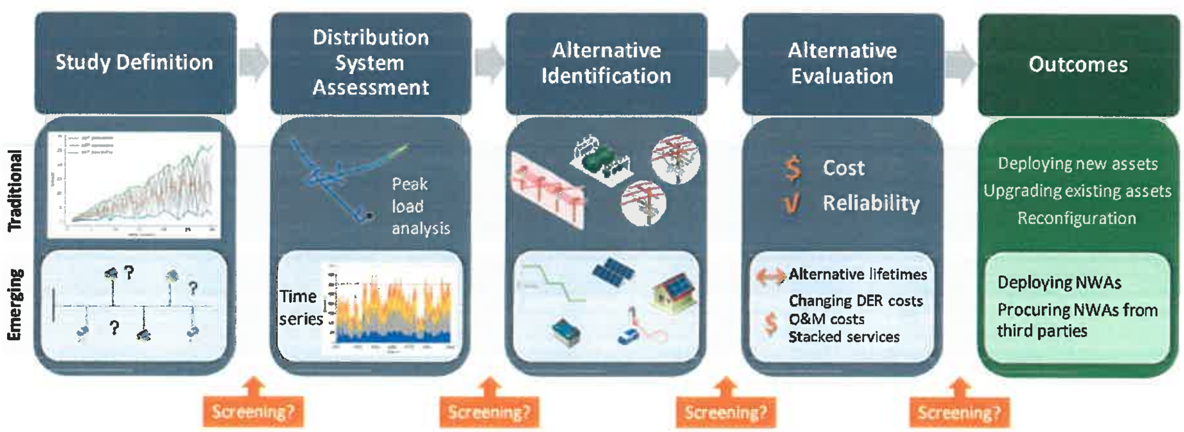

Figure 1-4
Integrating NWA screening into distribution planning process [2], [4]

NWA screening can be divided into criteria and methods as illustrated in Figure 1-5. This report discusses mainly NWA screening criteria but touches upon some screening methods as well. NWA screening criteria can be characterized either as quantitative or qualitative. Quantitative criteria involve comparing a include a quantifiable characteristic against a numeric threshold. Examples of quantitative screening criteria include minimum project cost in dollars and minimum project lead time in years. Qualitative criteria are useful for non-quantifiable aspects and/or when it is difficult to define specific numeric thresholds. Examples of qualitative criteria include forecast certainty and customer composition. Scoring/ranking criteria apply a score or otherwise rank NWA based on either quantitative or qualitative characteristics. Screening methods may be more detailed than screening criteria, potentially with multiple criteria encompassed within a single method to provide a more comprehensive screen, e.g. hosting capacity or locational value methods.

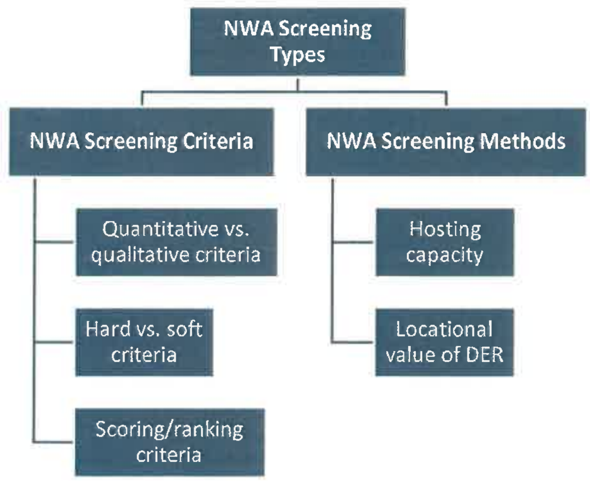

Figure 1-5
NWA screening criteria and methods

Figure 1-6 summarizes the key types of NWA screening criteria that have been proposed and the chapters of this report where the screening criteria is discussed.

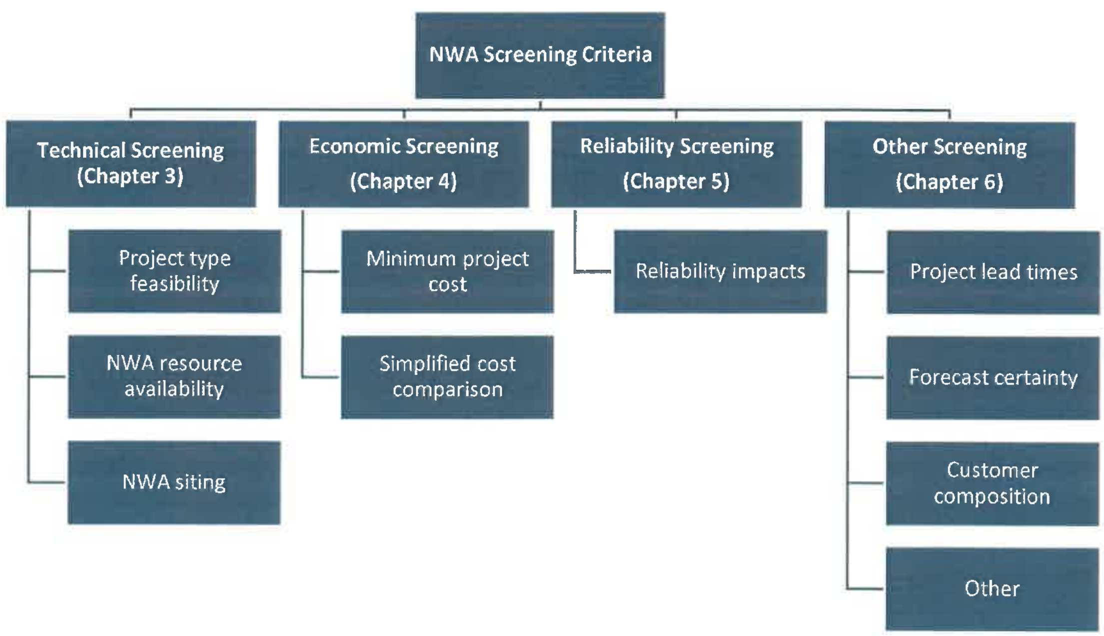

Figure 1-6
NWA screening criteria

Report Outline

The remainder of this report has the following structure:

- Chapter 2 reviews the NWA evaluation and screening practices in various jurisdictions in the U.S. and internationally. The review findings are used as a foundation for the discussion on the different screening methods in Chapters 3-6.
- Chapter 3 discusses technical screening including the distribution project types for which NWAs are feasible, the mapping of NWA resource types and distribution projects, and siting of NWA solutions.
- Chapter 4 reviews different types of NWA economic screening, including minimum distribution project cost, and simplified cost comparison.
- Chapter 5 discusses reliability screening of NWA solutions.
- Chapter 6 introduces other key types of NWA screening, including project lead times, forecast certainty, and customer composition.
- Chapter 7 concludes the report and discusses future research needs related to NWA screening criteria, methods, tools, etc.

2
SCREENING PRACTICES IN VARIOUS JURISDICTIONS

This chapter reviews NWA screening practices developed and used in various states across the U.S. and in the European Union. The review in this chapter is used as a baseline for the following chapters that discuss different types of NWA screening criteria and methods in more detail.

NWA evaluation processes typically begin with the assessment of the grid needs. Then, "initial NWA screening" is commonly performed to identify the grid needs that can be addressed by NWAs (project types, sufficient lead time, and potentially other criteria). Then, in some jurisdictions, "NWA prioritization screening" is performed to further prioritize the grid needs most attractive/suitable for NWAs. Table 2-1 provides a simplified summary of the NWA screening criteria in selected jurisdictions in the U.S. A more detailed discussion of each jurisdiction is provided in the subsections following the table. European NWA screening practices are also discussed in this chapter but are not summarized in Table 2-1 due to the different approach to NWAs utilized there.

Table 2-1
Simplified summary of screening criteria in the reviewed jurisdictions (initial screening criteria in green and project prioritization criteria in orange)

Criteria	California[5]	Hawaii	Massachusetts	Minnesota	New York[6]
Project types considered	Capacity, reactive power, voltage, reliability (back-tie), resiliency (microgrid)	Capacity, reliability (back-tie upgrade deferral), resiliency	Needs due to load growth or asset condition	Capacity projects only (initially), focus on N-0 projects	Load relief, reliability, combined load relief and reliability
Performance requirements / need characteristics		Peak power/ energy/duration, max # days with need, time of the year/day with need	Max. 20% of the peak		
Economic screening criteria	NWA unit cost, locational net benefit analysis	≥$1M for procurement, ≤$1M may be considered for programs		≥$2M	≥$1M (large projects) ≥$300-500k (small projects)
Minimum project lead times (years)	4-5	2	3	3	2-5 (large projects) 1.5-2 (small projects)
Forecast certainty	Year of forecast need, SCADA available, customers on assets	Qualitative factors, e.g., actual electric service requests vs. conceptual/high-level master plans, historical load growth trends			
Customer composition / market assessment	Prioritize projects with sufficient electric footprint for market-based NWA solutions	# customers for BTM solutions, land availability for FTM solutions			

California

In California, the investor-owned utilities (IOUs) are required to consider NWAs for deferring distribution investments following Distribution Investment Deferral Framework (DIDF), which is a set of California Public Utilities Commission (CPUC) approved upfront standards and criteria that IOUs will apply to conventional distribution projects to identify which of these projects could be candidates for deferral by DERs. The steps of the DIDF are illustrated in

[5] There are slight variations between the three California investor owned utilities.

[6] There are slight variations between the New York joint utilities.

Figure 2-1. As relevant to this report, DIDF defines the following two types of NWA screening/evaluation steps:

- **Initial deferral screens**: The objective of the initial deferral screens is to identify candidate deferral projects. The following two initial deferral screens are currently applied:
  - **Technical**: The technical screen addresses whether the technical feasibility of NWA solutions to address the identified grid need. Currently, NWAs are only considered for the following grid needs: capacity, reactive power (VAR), voltage, reliability (back-tie), resiliency (microgrid).
  - **Timing**: The timing screen addresses whether the NWA solution can be deployed sufficiently in advance of the forecast need. The current timing threshold is set to 4-5 years.
- **Prioritization metrics**: The objective of the prioritization metrics is to screen out the deferral opportunities that have a low probability of success. The following three prioritization metrics are currently applied:
  - **Economic/financial**: The economic/financial metric is used to prioritize deferral opportunities based on their likelihood for NWA solutions to be cost-effective. The economic/financial screen is based on locational net benefit analysis, which is considerably more complicated than simple minimum cost threshold and similar criteria.
  - **Forecast certainty**: The forecast certainty metric is used to prioritize the deferral opportunities based on their load forecast certainty. The metric evaluates the volatility of the driver for the distribution need, the scope of the of the affected assets, and the timeframe of the needs.
  - **Market assessment**: The market assessment metric is used to prioritize projects with sufficient electric footprint (sufficient number of customers) for market-based NWA solutions.

Other initial screens and/or prioritization metrics debated in regulatory stakeholder discussions [6] include:

<u>Customer specific factors including:</u>

- The number of customers causing the need (priority on scenarios with a large number of customers)
- Customer-specific development (priority for customer submittals for new/additional load)
- Ratio of projected need to customer or load on the circuit (priority on small ratio)
- Customer composition (priority on broad base of large customers requiring engaging relatively less customers)
- Customer composition (priority on homogeneous mix of customer classes)
- Availability of existing DER (procure services from them)

<u>Need characteristics</u>

- Project need (absolute and percentage)
- Historical load shape (high priority on modest historical increase on load)
- Peak duration (priority on relatively constant peak)

- Peak timing (priority on needs that can be addressed by different DER types)
- Weather factor adjustment (high priority on scenarios with average weather factors applied to a circuit)

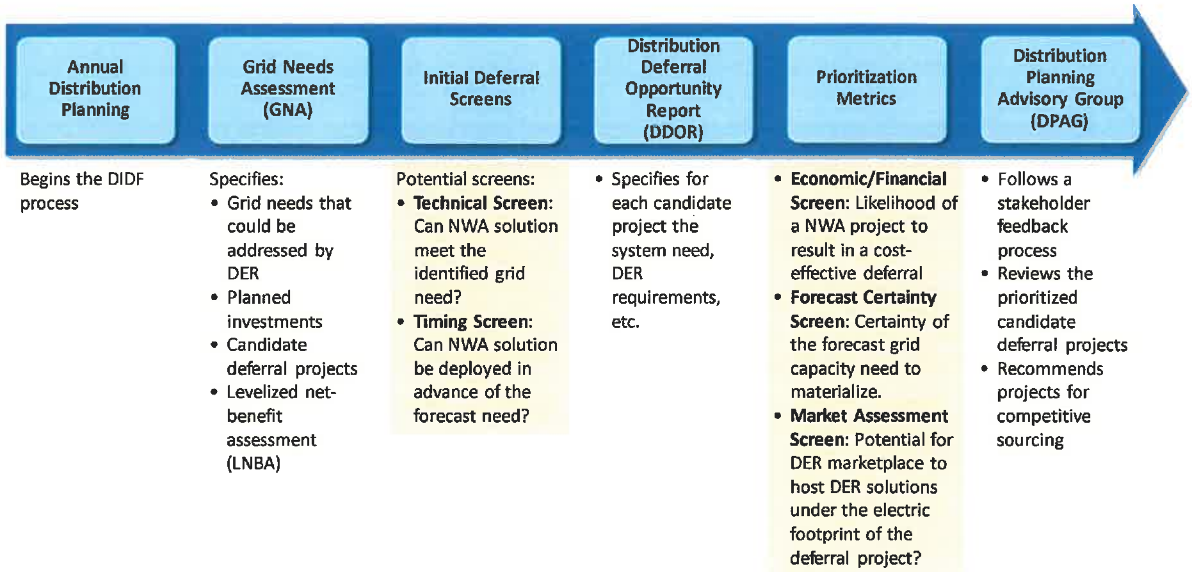

Figure 2-1
California Distribution Investment Deferral Framework (DIDF) [6]

After applying the prioritization metrics, the deferral opportunities are sorted in three to four tiers that are documented in the DDOR. For example, PG&E has developed a 4-tier ranking system: 1. Relatively High Ranking, 2. Relatively Moderate Ranking, 3. Relatively Low Ranking, 4. Already Sourced Elsewhere. PG&E has adopted the following prioritization metrics for the candidate deferral projects [7]:

Cost-Effectiveness Metrics

- Unit Cost (Estimated Capital Cost of the Project)
- Estimated Locational Net Benefit Analysis (LNBA) ($/kW-yr) (Deferral value for each year of deferral)
- Estimated LNBA/kWh ($/kWh-yr) (Ratio of LNBA value to kWh need per year)

Forecast Certainty Metrics

- Forecasted Need (Year) (Year that traditional project is needed)
- SCADA Available (Y/N) (Whether the circuit or device is equipped with SCADA to allow for easy monitoring of load and load profiles)
- Customers on Asset (Number of customers who could participate in DER solution)

Market Assessment Metrics

- Days/Year (number of days per year DER would need to be available to provide solution)
- Number of Grid Needs (Number of different locations, normally number of circuits, that DER's would need to be located in order to solve grid need

- Hours/Day (Maximum number of hours per day DER needs to be available to solve grid need)

Hawaii

In Hawaii, Hawaiian Electric has developed a methodology to evaluate transmission and distribution NWA opportunities [8]. The methodology was developed based on an industry survey [9] and stakeholder meetings. The methodology has a key difference to the NWA evaluation processes developed in other jurisdictions (e.g. California and New York) as it considers not only NWA sourcing options but also program and pricing options. The developed methodology, referred to as "NWA Opportunity Evaluation Methodology", consists of three steps illustrated in Figure 2-2. Steps 1 and 2 consist of different sets NWA screening criteria.

Step 1: T&D NWA Opportunity Screen

The first step of the process, referred to as "T&D NWA Opportunity Screen", has the objective to quickly and simply identify qualified T&D opportunities. This first step is purposefully designed to be over-inclusive as opposed to overly restrictive to capture all potential NWA opportunities. In this step, NWA opportunities are screened based on two screening criteria: technical and timing. Note that this step does not involve any economic screening criteria such as a monetary threshold.

Three types of T&D projects are considered technically suitable for NWA opportunities: capacity, reliability (back-tie upgrade deferral), and enhancing system resiliency. Projects that are not considered technically feasibly are: line/pole relocation/undergrounding due to street widening or related reasons; emergency and preventative equipment/infrastructure that are used preventing outages or catastrophic failures, restoring power after outages, and ensuring public safety; equipment replacement due to asset condition, damage, or failure; and new customer interconnections.

The timing criteria is to ensure sufficient lead time for the procurement process, program development, regulatory approval, and NWA solution deployment. Initially, the methodology will consider a two-year lead time, but more lead time may be needed depending on the complexity of the wires solution.

Figure 2-2
Hawaiian Electric NWA opportunity evaluation methodology [8]

Step 2: NWA Opportunity Sourcing Evaluation

The second step of the process, referred to as "NWA Opportunity Sourcing Evaluation", further evaluates and prioritizes the qualified opportunities based on four equally weighted criteria: performance requirements, forecast certainty, project economics, and market assessment.

The performance requirement criterion identifies if NWA solutions can reasonably meet the performance requirements of the identified grid need. The performance requirements include peak power and energy requirements, peak duration, maximum number of days the need occurs, and the time of the year and day the need can occur. Projects targeting critical needs are more likely to be subject to more stringent performance requirements and contractual terms. Projects with more lenient performance requirements are stated to be more suitable for NWAs.

The forecast certainty criterion qualitatively assesses the certainty of the magnitude and timing of the grid need. The criterion looks at qualitative factors such as: is the forecast is driven by actual electric service requests (high to moderate certainty) vs. conceptual/high-level master plans (low to moderate certainty) and if there are steady historical trends of load growth.

The project economics criterion is to identify opportunities that are likely to be cost-effective for procurement, programs, or pricing. T&D capital projects with a cost above $1M will be considered for procurement, and projects with a cost below $1M may be considered for targeted DER programs.

The market assessment criterion is used to assess projects based on their technical potential (the number of customers available for behind-the-meter solutions, and land availability for front-of-the-meter solutions) and supplier/solution diversity to ensure competitiveness and reliability.

Step 3: Action Plan

Step 2 leads to one of the following three tracks in Step 3:

- Track 1: Procurement of large (>$1M), certain (in-service date in 2 to 5 years) NWA opportunities, with high likelihood of success for procurement (performance & market criteria)
- Track 2:
  - Procurement if factors indicate re-evaluating for potential procurement in the future (e.g. >$1M, timing, uncertainty of grid need)
  - A program development for large (>$1M) opportunities that are cost-effective for the customers, and where the performance is likely to be met (e.g. new real estate developments)
  - Pricing development for small (<$1M) opportunities with sufficiently long lead time for customer adoption (may be longer than targeted program)
- Track 3: Implement wires solution for the non-qualified NWA opportunities that have criteria that cannot be met.

Massachusetts

MA Bill H.1725 [10] defines a list of requirements for "infrastructure resource facilities". These requirements, which are listed as follows, can be considered as NWA screening criteria:

- **Minimum cost threshold**: $1 million
- **Project type**: Need due to asset condition or load-growth. Does not include lines that are constructed, owned, and operated by a generator of electricity solely for the purpose of electrically and physically interconnecting the generator to the transmission system of a transmission and distribution utility.
- **Timing**: Date of need at least 36 months in the future
- **Loading limit**: Need that can be addressed by less than a 20% reduction of peak load.
- **Eligible NWA resource types (individually or combined)**: energy efficiency, energy storage, electric vehicles, load management, demand response, renewable distributed generation. Other resource types may also be approved by the regulatory entity.

Minnesota

Minnesota Public Utilities Commission has imposed the Minnesota rate-regulated utilities with certain requirements for non-wires alternative analysis, see, e.g., [11]. Among other things, the utilities are required to provide information on project types suitable for NWAs, timeline required to consider NWAs, cost threshold for considering NWAs, and NWA screening process. As follows, Xcel Energy's response [12] to these requirements is briefly discussed.

- **Project type feasibility**: Initially, only capacity projects are considered. In particular, mandated projects (i.e., projects where the utility is required to relocate assets due to public projects like road construction) and projects related to asset health and reliability are not deemed viable. N-0 (overload under normal condition) are deemed more viable for NWAs due to lower overloads and shorter durations. N-1 (overload under contingency, criteria for at least 3 MVA capacity risk until measures) deemed less viable for NWAs due to high overloads and longer duration of overloads.
- **Economic screening**: Minimum cost threshold of $2 million will be applied per the Integrated Distribution Plan requirements. For screening purposes, $400,000/MWh of battery cost is assumed.
- **Timing**: At least three years assumed to be required for internal analysis, RFP process, and construction. This could be slightly reduced with more experience.

New York

In May 2017, New York Joint Utilities filed a description of the NWA identification and sourcing processes that describes both NWA suitability criteria and how the criteria are applied as an integral part of utilities' capital and budgeting processes to identify NWA opportunities [13].

NWA Identification and Sourcing Process

The capital planning process identifies the system needs and the traditional solutions that address those needs to maintain and/or enhance system safety and reliability. This is accomplished by assessing the current and future system conditions against utility design standards and methodology to determine operating risks and solutions to mitigate the risks. Potential solutions for resolving the identified needs are developed and assessed based on 1) effectiveness in meeting the need, 2) cost, 3) implementation timing, and 4) risks associated with each option. Traditional solutions are prioritized based on available capital and resources against the risk of not addressing the system need within the timeframe of the capital plan. The capital plan includes the selected T&D solutions as part of the annual capital budget and multi-year (typically five-year) capital forecast. The plan is updated annually, and components of the plan are updated throughout the year.

The filing discusses the utilities' NWA identification and sourcing process shown in Figure 2-3. While all the utilities apply the same general process, the timing over the year and the resourcing within the utility differs between the utilities. The process, which is iterative and interactive, has the following steps:

- **Identify System Need & Capital Plan**: The process begins with the development of system needs within the capital planning process as discussed above.
- **NWA Suitability Criteria**: Then, the utilities will apply utility-specific NWA suitability criteria resulting in a list of traditional infrastructure projects that are candidates for NWA solutions. The criteria are discussed in more detail in the following subsection.
- **NWA Opportunity Identification**: Then, the utilities identify and quantify the timing, location, and other characteristics of the system needs driving the specific capital projects.
- **NWA Sourcing Development**: In this step, the necessary data is gathered, and the NWA RFPs are developed.
- **NWA Solicitation Process**: This final step consists of the procurement of the NWA solutions, which includes solicitations, bid/proposal review, negotiation, and contract award. The bid review is a utility-specific methodology that is outlined in each utility's BCA handbook [14]. Bids that successfully meet the RFP requirements are further evaluated to formulate portfolio(s) of solutions. Final contracts are negotiated for detailed operational and commercial terms.

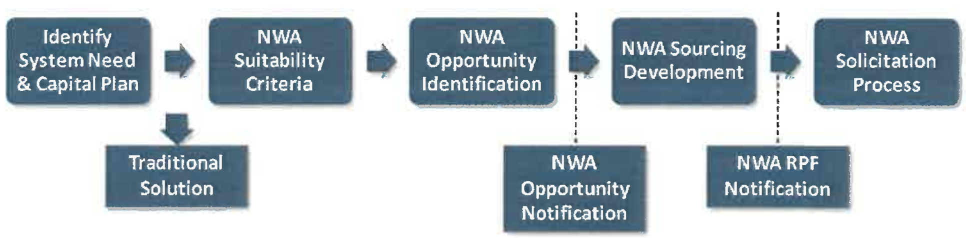

Figure 2-3
New York joint utilities' NWA identification and sourcing process [13]

For comparison, Figure 2-4 illustrates National Grid's NWA evaluation process in New York, which largely follows the process illustrated in Figure 2-3.

Figure 2-4
National Grid NWA evaluation process [15]

NWA Suitability Criteria

The NWA identification and sourcing process includes *NWA suitability criteria* that are applied annually to the traditional solutions identified in the current capital plan. Applying the criteria has three objectives: 1) identify projects best suited for competitive procurement of NWA, 2) give developers an opportunity to compete, and 3) provide a reasonable opportunity for success. Three types of NWA suitability criteria are considered:

- **Project type**: Only certain capital project types are deemed suitable for NWAs. Additionally, NWAs need to meet the design standards and operational requirements (voltage, protection, power quality, safety).
- **Timing**: Timing of the system needs to be appropriate for the estimated minimum time to procure NWA solution and the NWA solution to provide the system need.
- **Minimum Cost (of the Traditional Solution)**: Minimum cost is a threshold above which NWA solutions are more likely to be cost-competitive with traditional solutions and able to overcome the transaction and opportunity costs associated with responding to solicitations.

While all the NY joint utilities apply the same types of criteria, the criteria are utility specific. Table 2-2 lists the NWA suitability criteria for each of the NY joint utilities.

Table 2-2
New York Joint Utilities' NWA suitability criteria [16], [17], [18]

	Project Type Suitability Criteria	Timeline Suitability Criteria	Minimum Cost Suitability Criteria
Central Hudson	Load relief and reliability Other categories may be reviewed "as suitability changes due to State Policy or technological changes"	36 to 60 months for large projects 18 to 24 months for small projects	$1M for large projects $300k for small projects
Con Edison	Load relief or load relief in combination with reliability Other categories may be reviewed "as suitability changes due to State Policy or technological changes"	36 to 60 months for large projects (major circuit or substation or above) 18 to 24 months for small projects (feeder level or below)	No cost floor for large projects (very high cost) $450k for small projects
Orange & Rockland	Identical to Con Edison	Identical to Con Edison	Identical to Con Edison
National Grid	Load relief or load relief in combination with reliability Other categories may be reviewed "as suitability changes due to State Policy or technological changes"	24 to 36 months for large projects 18 to 24 months for small projects	$1M for large projects $500k for small projects
NYSEG & RG&E[7]	Load relief that do not involve customer contribution or have a specific customer in-service date that is sooner than the timeline suitability of 36 months Reliability projects and/or a combination of reliability and load relief	36 months from the time of the need	$1M (construction cost)

Europe

In Europe, most utilities are bound by the European Commission's unbundling rules which state that there must be separation between system operation and energy supply and generation. In essence, this means that utilities in Europe cannot own or operate DER, which has led to a somewhat different approach to NWAs. DER are still being considered as alternatives to conventional system upgrades, however this is typically referred to as flexibility procurement rather than NWAs. The most appropriate mechanism for procuring flexibility, given the ownership limitations, is still under debate. However, flexibility markets are emerging as a preferred option to ensure competitiveness [19]. A number of European utilities have been and continue to be involved in pilot projects demonstrating various flexibility market platforms. For example, in the Netherlands, the combination of the ETPA market platform [20] and the

[7] The following comments are made by NYSEG & RG&E. Project must pass all suitability criteria. Projects that pass all criteria will be prioritized based on the time of need. Not all projects may result in an RPF in a given year, projects not resulting in an RFP will be reevaluated in the planning process the following year.

GOPACS [21] congestion management platform allows the TSO and DSOs to resolve congestion issues in an intraday time frame.

The Energy Networks Association's Open Networks Project [22] in the UK, which encompasses all UK distribution network operators (DNOs) as well as the TSO, has a specific workstream related to flexibility services and has facilitated a number of local energy markets in the UK. The initiative has also outlined good practices and standards for UK utilities to adhere to when procuring such flexibility services, such as the standard flexibility contract that will be used by all UK DNOs and includes details around duration and scope of services as well as other obligations and contractual stipulations. The ENA is also working on streamlining the flexibility procurement process across the UK DNOs and has documented and collated the current approaches being taken by individual DNOs. In general, the DNOs follow the same approach of having a pre-qualifying stage, assessing assets based on a number of pre-qualifying criteria, followed by a procurement stage where assets are assessed based on commercial and technical parameters. Details of the pre-qualifying criteria for each DNO are provided in Table 2-3.

Table 2-3
ENA pre-qualification criteria [23]

	Northern Powergrid	Western Power Distribution	Electricity North West	UK Power Networks	Scottish and Southern Electricity Networks	Scottish Power Energy Networks
Minimum metering granularity	Half hourly	Minute by minute	Half hourly	Minute by minute	Half hourly	Minute by minute
Response time	5 minutes (restore)	15 minutes (secure/dynamic) 0-15 minutes (restore)	3 minutes (restore) 15 minutes (sustain)	30 mins (secure) Scheduled dispatch (sustain)	30 minutes (secure)	3 minutes (secure)
Minimum run time	30 minutes	1 hour	30 minutes	30 minutes	30 minutes	1-3 hours (flex product dependent)
Voltage level	At or below constraint & within boundary					
Flexible MW (note not asset size)	0.1	0	0.05	EHV/HV - 0.05 (can be aggregated) LV - 0.01 (can be aggregated)	0.05	0.05 (EHV)
Terms and conditions	Acceptance					
Procurement of non-energized assets: Must be energized	before contract signed	before operating window	2 months before operating window	and tested 1 month prior to service operating window	and tested 1 month prior to service operating window	1 month prior to service window
Other commitments		1. Commitments to build API 2. Acceptance of fixed price/market price				

The pre-qualified assets then receive technical and financial weightings in the procurement stage which determine the assets that are awarded contracts. Each of the DNOs splits the weighting as outlined in Table 2-4.

Table 2-4
ENA technical and financial weightings

	Northern Powergrid	Western Power Distribution	Electricity North West	UK Power Networks	Scottish and Southern Electricity Networks	Scottish Power Energy Networks
Financial	100%		60%	100%	30%	30%
Technical		100%	40%		70%	70%

The technical criteria include:

- provides a suitable solution within the required network location
- no service conflicts
- does not cause network issues during recovery
- management approach
- health and safety/environmental
- information security

The financial element incorporates the most competitive price the provider is willing to be paid for providing the flexibility service – either on a £/MWh (energy) or £/MW/hour (power) basis – dependent on the type of flexibility product.

3
TECHNICAL SCREENING

When considering a particular NWA as a mitigation alternative, one of the principal questions to be addressed is whether that specific NWA technology has the technical capability to resolve the identified need. A detailed NWA study can certainly provide the answer to this question, but there are a number of technical screens that can be employed to either advance that NWA further into the planning process or rule it out on the grounds of technical infeasibility.

Project Type Feasibility

At a high level, there are certain types of distribution needs that are suitable for NWA deployment, and others that are not. Table 3-1 lists a number of projects that can feasibly be deferred by NWA solutions. Thermal capacity constraints, which are traditionally solved by installing or upgrading transformers and lines, are perhaps the most fitting for NWA application since the types DER that are used as NWAs, such as PV or demand response, inherently provide additional capacity. This is reflected in many of the screening practices discussed in the previous chapter, where capacity deferral is identified as a primary use-case. Load growth driven capacity projects are also frequently identified, with sufficient lead time to allow evaluating NWAs. Furthermore, the conventional solutions required to address capacity constraints tend to be high cost, increasing the chances for NWA solutions to be cost-effective. Reliability related projects, i.e. capacity issues due to contingency conditions, may also be alleviated with NWAs, although additional controls or capabilities may be needed in such cases. Voltage related needs can potentially be met by NWAs; however, suitability is dependent on the type of NWA, which will be discussed further in subsequent sections. NWAs could also be applicable for resiliency purposes, providing supply to load that would otherwise be isolated during a contingency, but with enhancements likely required.

Table 3-1
Projects that may be suitable for deferment using NWAs [24], [25]

Types of System Projects	Example Equipment	DER Services
Thermal capacity upgrade projects (also referred to as "N-0 capacity")	Substation transformers Reconductoring/circuit rebuilding Line conductors	Distribution capacity
Voltage/VAR projects Conservation voltage reduction (CVR) Voltage/VAR optimization (VVO)	Capacitor banks Load tap changers Line voltage regulators Line conductors	Voltage/VAR support
Reliability upgrades: capacity upgrade projects driven by outage contingencies (also referred to as "N-1 capacity" or back-tie)	Substation transformers Reconductoring/circuit rebuilding Line conductors	Distribution capacity (under contingency conditions)
Resiliency upgrades: new supply paths for increased resiliency	New substation New feeders New switching points New tie lines	Resiliency through a microgrid (serve load otherwise isolated under contingencies)

Although NWAs have the potential to mitigate certain distribution issues, there are other types of constraints where the traditional solution is the only viable one. Some of these non-deferrable projects are listed in Table 3-2. Aging or damaged assets that are critical for maintaining secure supply must be repaired or replaced, NWAs are not an alternative for infrastructure like poles and lines. Similarly, green field expansion to facilitate new commercial or residential developments cannot be served by NWAs alone. NWAs are also not deemed suitable for mandated projects, where the utility is mandated to relocate existing equipment due to, e.g., a road construction. Reliability measures that are non-capacity related like switching or fault detection cannot be achieved by DER technologies. Equally, emergency conditions that necessitate a fast response time are not typically suitable for NWAs that have longer duration lead times.

Table 3-2
Projects that are not suitable for deferment with NWAs [24], [25]

Types of System Projects	Reason why not deferrable
Repair/replacement of damaged/deteriorated infrastructure (e.g. electrical equipment, structural equipment)	Equipment necessary to support electrical service and safe operation of the electrical system for both load and DER
Non-capacity related reliability (e.g. automation, fault detection, sectionalizing equipment)	DERs don't reduce outage duration by sectionalizing circuits or detecting faults
Mandates/public requirement projects (e.g. relocation of facilities to accommodate, e.g., a road construction)	Requires relocating assets, which is unlikely possible to be replaced by DERs
Operations and maintenance (e.g. equipment testing/ inspections, managing vegetation and animals, etc.)	Function not provided by DERs
Emergency preparation and response	Short timeframe to replace/repair damaged equipment to restore electrical service
Minimum infrastructure required to serve customers	Obligation to serve

The type of need can provide an early screen for whether NWA are generally a suitable mitigation measure or not. Once NWA are deemed appropriate, the different types of NWA technologies can be screened further on the basis of technical feasibility for the required application.

Mapping of NWA Resource Types and Applications

Utilities can consider three types of NWA options: competitive solicitations, customer programs, and pricing mechanisms [26]. In competitive solicitations, the utility seeks to competitively procure the NWA DER assets. In some jurisdictions, the utility procures, owns and operates the DER assets, whereas in other jurisdictions the utility procures the NWA as a service from third party owned and operated DER assets. In customer programs, such as demand response and energy efficiency programs, the utility compensates the participating customers. Pricing mechanisms, which involve making changes to customer tariffs and which are mainly applicable for providing thermal capacity, are out of the scope of this report. It is possible for these three NWA options to overlap. It may also be possible to utilize more than one of the options for a given NWA application (e.g. address thermal capacity application with a demand response program combined with a utility-owned energy storage system).

Depending on the identified distribution need, certain NWA technologies may or may not be suitable as an alternative. Some combinations of NWA resource types and NWA applications are infeasible and thus, can be excluded from any further consideration.

A mapping of NWA resource types to various distribution applications is provided in Table 3-3. Thermal and reliability constraints can be relieved by most NWA resources, although using PV and demand response come with a caveat that there must be time alignment between the distribution need and the resource output. Although most resources are technically suitable for reliability applications, contingency scenarios often require larger capacities and longer durations, which may rule out certain smaller scale resources such as demand response. This will be discussed more in the following section. NWA technologies are generally not suited for voltage issues, however the addition of a smart inverter to a storage or PV system can provide this capability. Optimal NWA solutions may include a combination of different resource types (including conventional upgrades), e.g. PV for resiliency purposes would likely need to be paired with other technologies such as storage.

Table 3-3
Mapping of NWA Resource Types and Applications

	Thermal	Voltage	Reliability	Resiliency
Energy Storage	✓	✗	✓	✓
Energy Storage with Smart Inverter	✓	✓	✓	✓
PV	✓*	✗	✓*	✓**
PV with Smart Inverter	✓*	✓*	✓*	✓**
Demand Response	✓*	✗	✓*	✗
Energy Efficiency	✓*	✗	✓**	✗

*if the need and the availability of the resource are sufficiently aligned
** if combined with other resource types

NWA Resource Availability

Because some NWAs rely on availability of a fuel source e.g. PV, or on external factors to achieve results (e.g. availability of customer load for demand response program), one of the biggest concerns that emerges when considering an NWA is whether the resource will be available to provide support when it is needed. Some simple screens can be incorporated early in the planning process to rule out resources whose output does not align with the timing of the constraint.

PV by itself as a NWA is not a feasible solution for an issue that arises outside of daylight hours. Two examples of how this screening would apply are shown in Figure 3-1, which presents load and PV output for two feeders in the same service area over the course of a year. Feeder 2 experiences peak load during the day in summer, which makes PV a potentially suitable solution, whereas Feeder 3 peaks in the evening in winter, meaning PV should not be pursued as an alternative. This highlights the importance of accurate load modeling, as the coincidence between peak load and resource output, and hence the applicability of that resource as a NWA, is dependent on the nature of the feeder load.

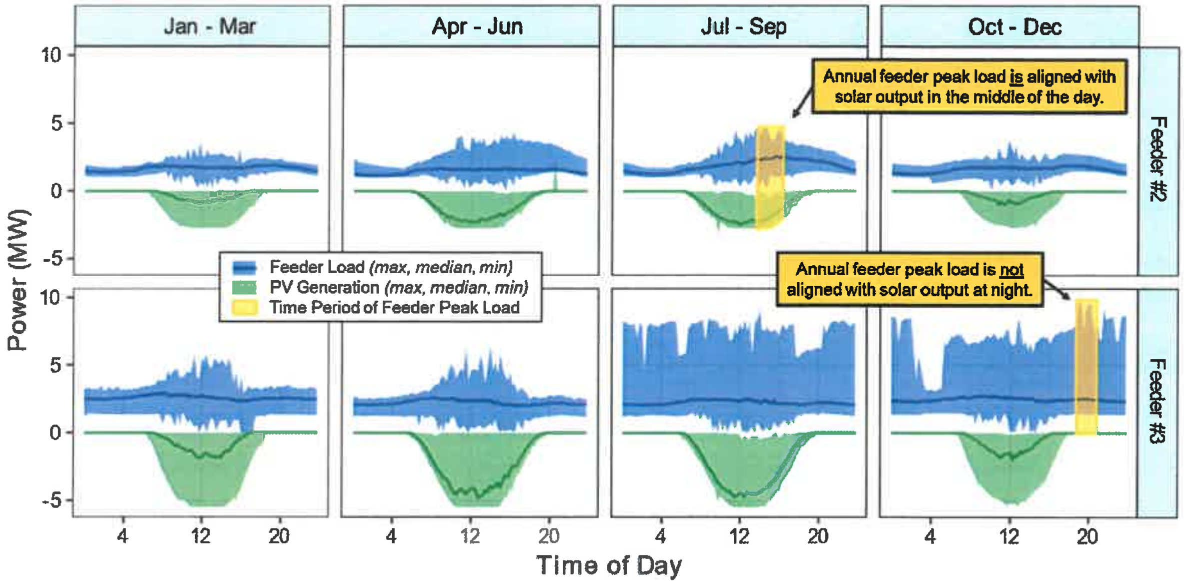

Figure 3-1
Screening NWA time-alignment [27]

For NWA resources such as demand response, that are based on controlling customer loads or assets, resource availability may refer to the coincidence between the customer assets/loads and the system load. For example, leveraging customer air-conditioners as demand response resources may not be technically feasible as a NWA for distribution capacity if the air-conditioning load does not correlate well with the circuit load.

For demand response and related NWA resources, NWA resource availability may also refer to the availability of the right types of customers and the ability to procure the desired response, either via aggregators or utility designed programs. Screening criteria related to this are discussed in chapter 6.

It is also important to consider practical limitations for leveraging such resources. It may be necessary to limit the number of demand response events per year, the number of events on subsequent days, the duration of events, etc. to avoid customers opting out of the program. For example, demand response may not be suitable for a reliability application where the capacity is needed in a contingency situation over several days or weeks. Such practical considerations can be translated to the following example NWA screening criteria:

- The maximum number of times per year that the NWA service is required
- The maximum duration of a continuous event that a NWA service is required
- The maximum subsequent days that the NWA service is required

These screening criteria may be flexible, as it may be possible to limit the number of times each customer is called in a demand response program by subscribing more customers than is required and cycling the response among multiple customers, for example. Using demand response resources, which are already utilized for bulk system reliability applications, for distribution level NWA capacity applications too, may result in increased use of the resources. The increased utilization may reduce customer willingness to participate in the demand response program or may require an increased customer compensation. A more detailed discussion of screening demand response as a distribution capacity resource can be found in [28].

NWA Siting

Depending on the issue that arises as part of the planning study, the NWA being employed for mitigation will likely need to be installed at a particular location on a distribution feeder for maximum effectiveness. If thermal constraints are the predominant issue, the NWA will need to be located downstream of the affected element. If voltage violations need to be relieved, resources are best located electrically as close as possible to the circuit section(s) with voltage violations.

Additionally, the characteristics of the circuit itself and how it is operated need to be considered, by accounting for things like hosting capacity and switching possibilities. When installing a NWA to mitigate a constraint, care needs to be taken to ensure that the NWA itself can be hosted and will not cause problems at times when constraint relief is not needed. Likewise, awareness of alternate system configurations is important. Feeder switching is often used to meet growth, for maintenance, or as part of day-to-day operations. However, this switching may reduce or negate the effectiveness of an NWA. A resource that was downstream of a constrained asset may not be there to provide relief after a reconfiguration. This is illustrated by the simple example given in Figure 3-2, which shows two substations with a feeder in between that can be reconfigured by opening/closing the two connecting switches. In Configuration 1, an NWA is installed at Bus C to mitigate the transformer overload. If, however, the circuit needs to be reconfigured to Configuration 2, the NWA at Bus C is now connected to the neighboring transformer and not the overloaded one, meaning that relief is no longer available for the overloaded transformer. This is an illustrative example, but in reality, configurations may be much more complex, particularly in meshed systems, which already present challenges due to multidirectional power flows which can reduce the effectiveness of NWA solutions.

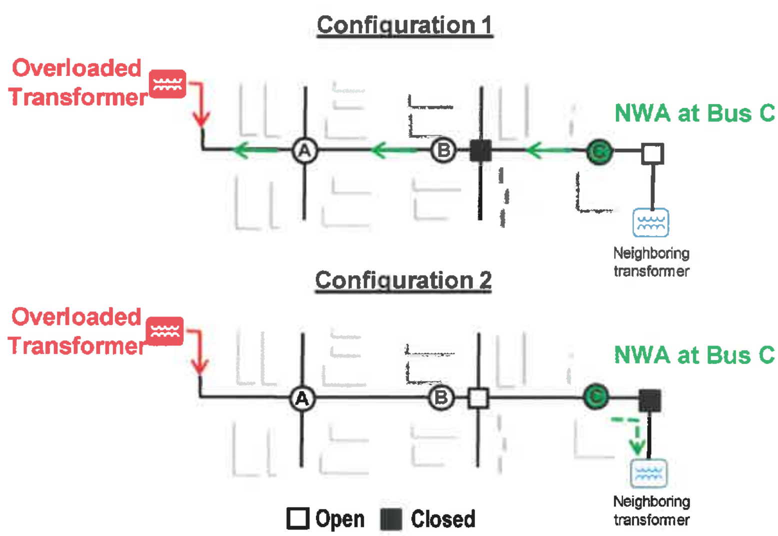

Figure 3-2
Example of reconfiguration impact on NWA effectiveness [1]

Land availability can be either a limiting factor or a benefit depending on the NWA type. For certain types of DER, such as PV, substantial land area is required. A 20 MW PV plant could require a geographical footprint of between 80 and 120 acres [29], [30]. While storage has a higher power/energy density per acre than PV, 150-350 MW per acre and 550-780 MWh per acre for lithium-ion batteries [30], the spatial requirement is still significant. This means that if the need for relief arises in a highly populated urban area, these resources would not be suitable mitigation solutions. Demand response, on the other hand, is an NWA that does not have any spatial requirements and thus may be a suitable alternative in situations where there is limited physical space for upgrading a transformer for example. Land use limitations or planning permission can also limit potential NWA sites; certain sites may be restricted in the way that land can be used, there may be protections around nature and wildlife, land may be zoned for specific purposes such as housing, or land owners may be unwilling to sell a particular site. Furthermore, safety and access restrictions may present challenges, potential NWA locations might not be easily accessible by fire departments, may obstruct access to other locations, or weaken structures and prove dangerous in the case of a fire.

Although demand response may be suitable in cases where land availability is limited, there are other siting related aspects to consider. To achieve the desired response, there must be a sufficient number of customers downstream of where the issue is arising. The composition and class of those customers is also important. Critical load customers such as hospitals or data centers are not suitable for demand response. Similarly, depending on the type of demand response program that's under consideration, residential/commercial/industrial customers may not be capable of providing the required response due to the make-up of their load.

Screening good locations for NWAs should ideally encompass all of the outlined siting considerations and allow a planner to easily identify both good and bad areas of the distribution system for locating NWAs. Figure 3-3 shows an example where locational value of PV is calculated based on the anticipated overloads. It can be seen that the most beneficial locations are towards the end of the feeder downstream of the overloads. The streamlined methodology used in this example is detailed in [27] and incorporates the various siting and availability factors described above.

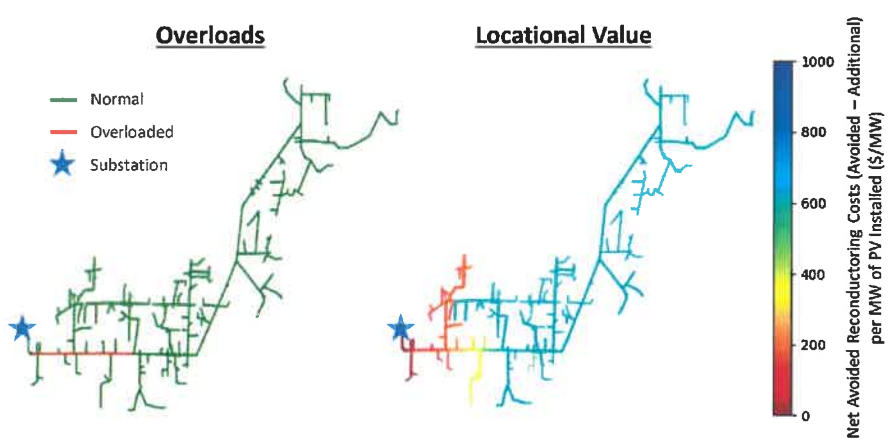

Figure 3-3
Screening good NWA locations [27]

Other NWA Technical Requirements

Depending on the distribution system need and the associated conventional solution, there may be additional technical requirements that can be considered as screening criteria for NWA. For example, in N-1 capacity applications, where the distribution capacity need is driven by system contingencies, the NWA solution may need to be able to respond in the matter of minutes, a requirement that may rule out some type of NWA resources, e.g., price-based demand response programs.

4
ECONOMIC SCREENING

Economics is a key consideration for utilities when assessing NWAs, as highlighted by the poll results discussed in Chapter 1: the economic efficiency of NWA solutions is compared against conventional wires solutions, and the least-cost solution that meets the planning criteria is typically selected, although other selection criteria, such as reliability (see Chapter 5), may also be considered.

The "Alternative Evaluation" stage of the distribution planning process (see Figure 1-4) involves performing a detailed economic comparison of the wires and non-wires alternatives identified. Discussing the various approaches for performing these detailed economic comparisons is beyond the scope of this report, however more detail can be found in [31], [32]. Instead, this chapter focuses on economic *screening* criteria and methods that can be applied in earlier stages of the planning process to evaluate whether the expected economic merit of certain NWA solutions warrants transitioning them to the next stages of the planning process.

Economic Screening Metrics

Capital Cost

The capital cost of the conventional solution is a first type of economic screening metrics that can be used to decide whether non-wire alternatives should be considered. Notionally, NWAs are economically attractive when costing less than conventional solutions. The availability of low-cost wires solutions makes that outcome less likely. Further, the value of the avoided or deferred wires solution must be sufficient to also cover for the NWA transaction[8] costs.

For these reasons, a **minimum project cost** threshold is one of the commonly used NWA screening criteria (see Table 2-1): NWAs are considered only when the cost of the conventional solution is higher than this threshold. The minimum project cost threshold should be set sufficiently low so that NWAs do get considered, but sufficiently high to avoid considering NWAs when low-cost wires solutions are available, making NWAs unlikely viable from an economic standpoint.

The minimum project cost criteria can be made specific to the type of the grid need considered. For example, the New York Joint Utilities have separate minimum cost thresholds for "large" and "small" projects, see Table 2-2. Differentiated cost thresholds based on grid needs can help gauge more accurately the economic feasibility of NWA solutions at the screening stage.

In practice, the minimum project cost criterion tends to rule out NWA solutions for applications such as voltage regulation support, and power quality, where low-cost conventional solutions are commonly available. While NWA solutions may be technically feasible for such applications,

[8] The costs of evaluating, procuring, and deploying NWA solutions are expected to be higher as compared to conventional wires solutions due to the limited experience that utilities currently have with NWAs. The transaction costs of NWA solutions are expected to decrease as utilities gain more experience with NWAs and as utility processes to evaluate and deploy NWAs become more established.

they are unlikely to be economically efficient. Table 4-1 lists example scenarios where NWA solutions are likely to pass the minimum project cost criterion, reflecting that the cost of the conventional solution is deemed high enough for a non-wires alternative to potentially be more economically efficient.

Table 4-1
Minimum cost criterion: example scenarios

Grid need	Scenarios where NWAs are likely to pass minimum cost criterion
Distribution thermal capacity	Urban networks with high land and construction costs (e.g. ConEd BQDM project [33])
	New substation
	New substation transformer bank
	Entirely new feeder
	Long reconductoring
Reliability	Long rural network, where grid hardening and enhanced automation are either not available or effective, and where constructing alternative supply points or new feeders is expensive

Deferral Value

NWAs are frequently considered for deferring conventional wires investments, as opposed to permanently avoiding them. In such cases, the value of deferring the implementation of a wires solution can be considered as a more accurate screening criteria than simply using a capital cost threshold. The deferral value depends on the length of the deferral time period, the planned first year of in-service (if the asset was not deferred), the lifespan of the deferred asset, and various other financial and economic assumptions, see [34].

Figure 4-1 illustrates the deferral value of a distribution asset with a 30-year lifespan with respect to the deferral length and the planned in-service year of the asset to be deferred. Longer deferral time periods and closer in-service dates lead to higher deferral values. For this illustrative example, when the first year of in-service is planned for Year 1 (i.e. distribution assets needed now), the deferral values range from ~8% to ~56% of the year-0 install costs depending on the deferral duration.

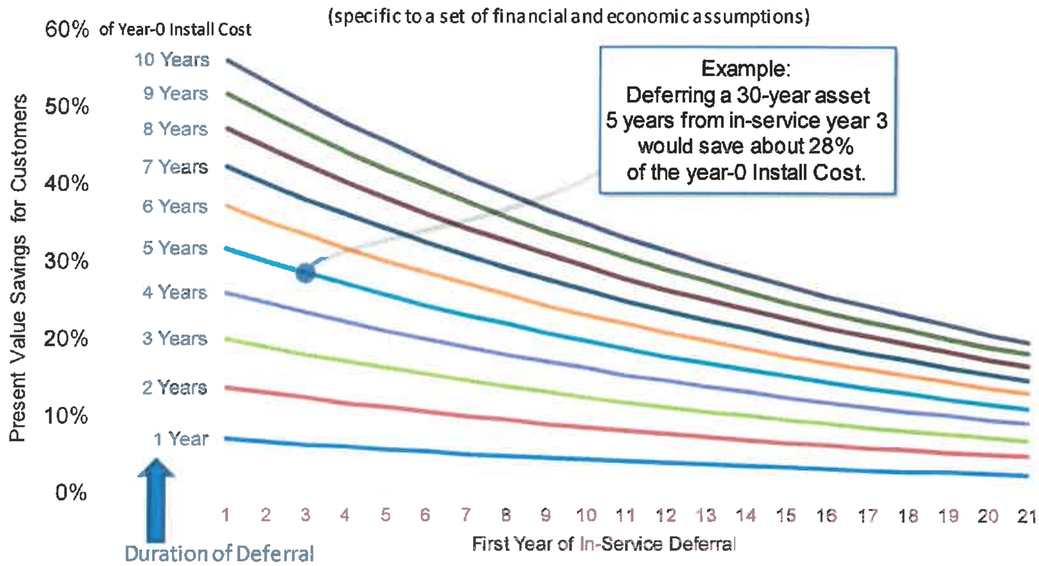

Figure 4-1
The deferral value of distribution assets as a function of in-service data and duration of deferral. Each curve shows the deferral value (present value savings for customers as a percentage of the asset install costs in year 0) with respect to the first year of in-service of the deferral. The curves are created with specific set of financial and economic assumptions for an asset with a 30-year lifespan. For details, see [34].

Similar to the minimum project cost threshold, a **minimum deferral value** threshold can be defined. While more complex to calculate than the minimum project cost, minimum deferral value threshold is also more precise as it factors in several key assumptions including the lifespan of the deferred asset, deferral duration, and first year of in-service. Similar to the minimum project cost threshold, the minimum deferral value threshold should be set to at least cover for the expected incremental transactions costs of NWA solutions going beyond the baseline set by wires solutions.

The minimum project cost threshold has the advantages of simplicity and transparency. However, the minimum deferral value can also be useful for selecting a minimum project cost threshold in that it captures additional dimensions including the time value of money. For example, the expected transaction costs of NWA solutions can be set as the minimum deferral value, which can then be translated to the minimum project cost based on certain deferral assumptions.

Figure 4-2 shows the minimum project cost threshold for three NWA transaction costs (50k, $100k, and $200k) assuming a 30-year lifespan for the deferred distribution asset, and other financial and economic assumptions equal to Figure 4-1. In this illustrative example:

- Assuming NWA transaction costs >$100k and deferral durations ≥5 years, the minimum project cost threshold could be set to $300k.
- Alternatively, assuming NWA transaction costs >$200k and deferral durations ≥3 years, the minimum project cost criterion could be set to $1M.

While Figure 4-1 and Figure 4-2 are simple illustrative examples, they demonstrate the mechanics of using deferral values as a screening metrics for NWAs, possibly combined with a minimum project cost criterion.

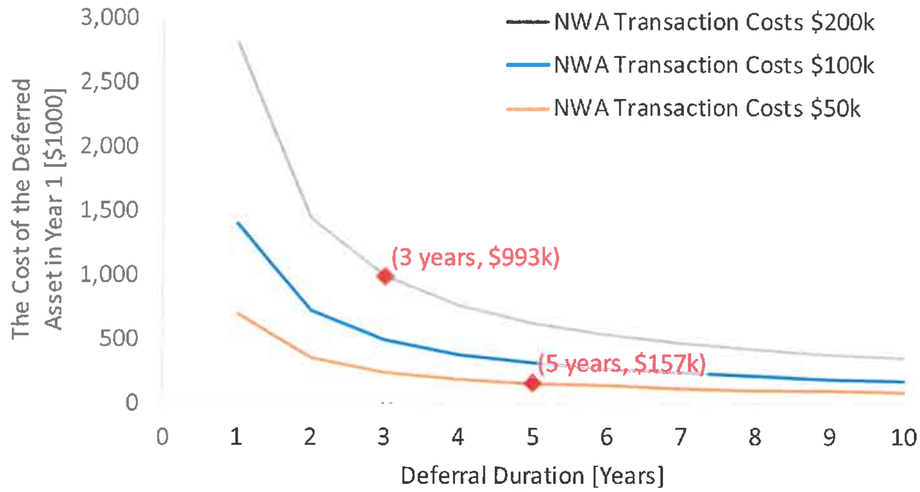

Figure 4-2
Illustrative example of minimum project cost with respect to the deferral duration for NWA transaction costs $50k, $100k, and $200k

Other Screening Metrics

The deferral value concept leads to two additional/alternative NWA screening criteria:

- **Minimum deferral time period (years)**: As illustrated in Figure 4-1 and Figure 4-2, the deferral value is low for very short deferral durations and thus, less likely to exceed the higher transaction costs of NWA solutions. Hence, it may be possible to exclude projects with very short deferral time periods purely based on economic reasons. This screening criterion is connected to the minimum lead time criterion discussed in Chapter 6 but differs for grid needs with required in-service date in the future. For example, a grid need with an in-service date four years in the future and a deferral time period of 1 year may pass the minimum lead time criterion but not the minimum deferral time period criterion.
- **Maximum deferral time period (years)**: Evaluating deferral over very long time periods is subject to a high degree of uncertainty due to the challenges of forecasting load and DER growth over long time periods. As illustrated in Figure 4-1 and Figure 4-2, the deferral value also has diminishing marginal increments for long deferral periods. In practice, the maximum deferral time period considered is likely chosen based on the time horizon used in distribution planning or NWA evaluation process. The maximum deferral time period may also be influenced by the available load forecast time horizon.

Finally, screening metrics can be normalized. For example, the deferral value can be expressed as an annual value (in $/yr), and can be even normalized based on the size of the assed deferred (in $/kW-yr). State-specific methodologies such as the CA locational net benefits analysis (LNBA) approach commonly use such normalization as a way to provide a quick way to compare multiple wires and non-wires options.

Simplified Cost-Benefit Analysis

The minimum cost and minimum deferral value screening metrics discussed above do not explicitly compare the NWA cost to the cost of the conventional solution; they are simply quick guidelines based on the expected avoided cost. To be deemed viable, NWA solutions would still need to prove higher cost efficiency. To this end, as part of the screening process, the minimum project cost criterion can be complemented with a basic cost-benefit analysis comparing the costs and benefits of the wires and NWA solutions in a simplified manner.

This simplified cost-benefit analysis is not to replace the detailed economic comparison of the identified wires and non-wires alternatives that is performed at "Alternative Evaluation" stage of the distribution planning process (see Figure 1-4). Instead, the simplified cost-benefit analysis intends to flag "false positives" early, that is projects that would pass the minimum project cost criterion, but where the wires solutions would still be clearly more economical than NWAs.

Figure 4-3 lists important NWA cost and benefit categories. The applicable categories depend on the NWA solution considered. For example, some cost categories are only relevant for NWA solutions involving customer assets while other categories are only relevant for solutions procured and deployed by the utility. In addition to the cost and benefit categories shown in Figure 4-3, NWA solutions may also involve costs or benefits that are not monetized today, including: cost of carbon, emissions, land use, visual impacts, etc. The value of some of these costs and benefits, e.g., cost of carbon, could exceed some of the cost/benefit categories listed in Figure 4-3, if they become monetizable in the future.

A comprehensive analysis of all the cost and benefit categories listed in Figure 4-3 may be too tedious for early economic screening of NWA solutions. Instead, it may be acceptable as a first order analysis to focus the simplified cost-benefit analysis screening on capital costs, which tend to dominate the overall costs of wires and NWA solutions.

Detailed NWA capital cost data is typically received from RFP responses at the solicitation stage of the distribution planning process (see Chapter 1). Instead, the simplified cost-benefit analysis screening would likely rely on publicly available cost data, or cost data received from previous RFPs. While less accurate, such cost data can be useful for screening purposes.

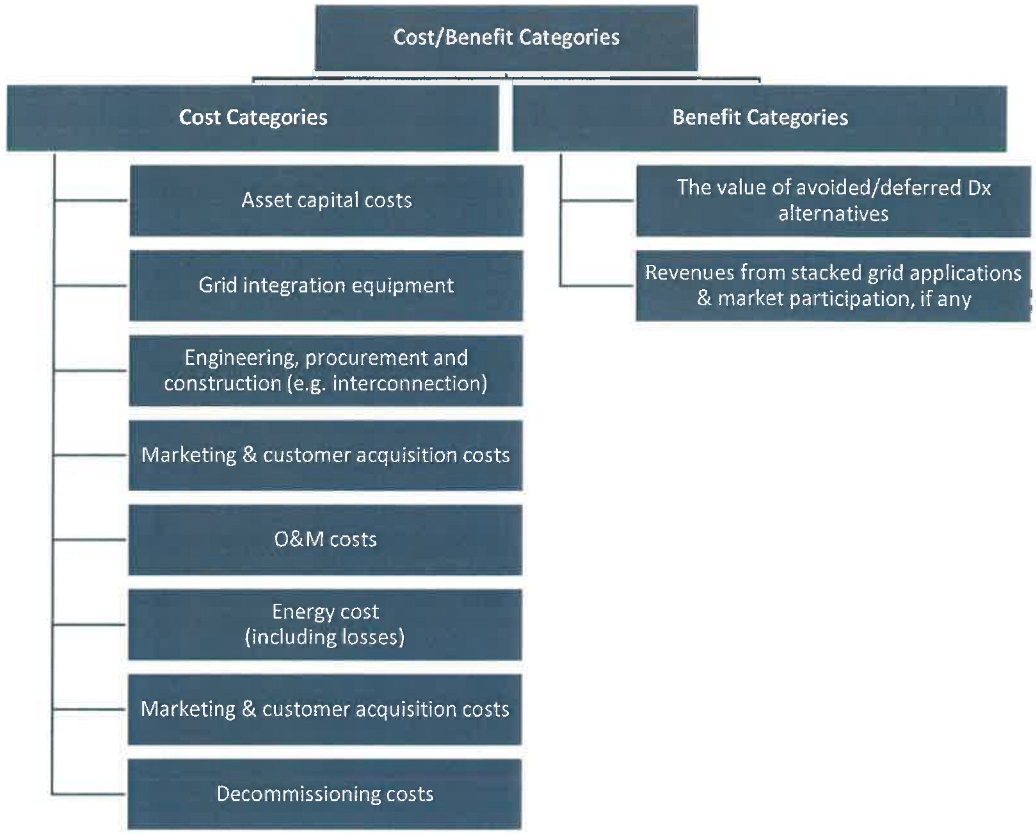

Figure 4-3
NWA cost and benefit categories

DER Cost Estimates

High-level cost estimates and ranges are provided below for energy storage systems, PV systems, collocated PV and storage systems, and demand response programs. Reviewing costs of energy efficiency programs and other DER was beyond the scope of this report.

Energy Storage Cost Estimates

Energy storage cost categories and cost line items are listed in Table 4-2. Publicly available energy storage cost information can be found in [35] and more detailed energy storage costs and cost projections are provided in [36].

Table 4-2
Energy storage cost categories and cost line items [35], [36]

Cost Category	Cost Subcategory	Cost Line Items
Upfront owner's cost		Project development, program development
Turnkey installation costs	Energy storage system	Battery/storage medium, power conversion system (PCS), Balance of plant (BOP), control
	Grid integration equipment	Transformers, switchgear, protection, etc.
	Engineering, procurement and construction (EPC)	ESS installation, site installation, project management, engineering, ESS shipping, grid integration installation, commissioning and acceptance
Operations & maintenance (O&M)		Energy costs (charge/discharge losses, housekeeping power, self-discharge), annual software licensing fees, fixed and variable maintenance, insurance, scheduler fees, project administration, ESS extended warranty, performance guarantees, augmentation or overhaul
Decommissioning		ESS and grid related decommissioning

Table 4-3 lists cost estimates for Lithium ion energy storage systems in T&D grid support applications in 2019. For NWA screening purposes, it may be reasonable to focus on the turnkey installation costs[9] that dominate the overall costs of energy storage systems. When evaluating energy storage NWA solutions with in-service dates several years in the future, it is recommended to consider the rapidly declining energy storage cost projections. Compared to 2019, Lithium ion energy storage system cost are estimated to roughly half by 2030, for details see [35] and [36].

[9] The turnkey installation cost ranges, which are given both as $/kW and as $/kWh, reflect the cost variation based on location, site conditions, project specific requirements, market conditions, and other factors. Caution should be used in evaluating the costs simply through these ranges, as scale and energy duration impact a specific project's overall economics.

Table 4-3
Cost estimates for Lithium ion energy storage systems in T&D grid support applications in 2019 [35], [36], [37]

Cost Category	Sub Cost Category	Cost (Range) Estimates / Parameters
Turnkey installation costs	Energy storage system, grid integration equipment, engineering, procurement and construction (EPC)	1-5 MW, 2hr systems: $1000 - $2000/kW, or $500 - $1000/kWh 10-20 MW, 4hr systems: $1350 - $2400/kW, or $340 - $600/kWh
Operations & maintenance costs	Fixed maintenance	1.5% of the capital costs per year
	Warranty	1% of the capital costs (after 3 years)
	Battery replacement or augmentation (includes battery modules, BOP upgrades, shipping, labor, and equipment)	$200-300/kWh
	Losses[10]	Energy storage round-trip: 85% PCS efficiency: 95% Energy costs: $0.055kWh
Disposal/decommissioning costs		4 MW, 1hr systems: $54/kWh 2 MW, 2hr systems: $45/kWh 1 MW, 4hr systems: $39/kWh

PV Cost Estimates

Table 4-4 lists ranges for the capital costs and operations and maintenance costs (O&M) of solar PV systems in Q3 2019. More details on PV system costs can be found in [38] and [39]. For NWA screening purposes, it may be reasonable to focus on the PV system capital costs. Given that PV system costs have declined year over year from 2016 through 2018 [40], it is recommended to consider future PV system cost projections when evaluating NWA solutions that are deployed several years in the future. For NWA screening purposes, PV system decommissioning costs, if considered, can be assumed to be 7% of the installed costs [41].

[10] Energy storage losses are highly dependent on the energy storage operation. The parameters provided here in conjunction with estimated energy storage operating profile can be useful for high-level loss estimates.

Table 4-4
PV system cost estimates

PV Technology Scenarios	Total Capital Costs [$/kW$_{AC}$]	Annual Operations and Maintenance Costs [$/kW-yr]	Time of Cost Estimates	Source
Utility-scale (26-MW$_{DC}$, 20-MW$_{AC}$)	1,263 - 1,463[11]	14.04 - 17.31[12]	Q3 2019	[38]
Utility-scale (13.2-MW$_{DC}$, 11-MW$_{AC}$)	1,708 – 2,012[13]	16.60 – 20.04[14]	Q3 2018	[39]
Utility-scale (5-MW$_{DC}$, 3.85-MW$_{AC}$)	1,869[15]	14.00[16]	Q1 2018	[42]
Commercial (140-MW$_{DC}$, 100-kW$_{AC}$)	2,530 – 2,635[17]	18.43[18]	Q3 2019	[38]
Residential (5.65-kW$_{DC}$, 5-kW$_{AC}$)	3,196 – 3,306[17]	$20.61[18]	Q3 2019	[38]

PV Plus Storage Cost Estimates

Table 4-5 lists PV plus storage cost estimates. Publicly available solar plus storage cost estimates can also be found in [43] and a more detailed discussion on solar plus storage costs can be found in [41]. For screening purposes, it may be reasonable to focus on the installed costs of PV plus storage systems. For screening purposes, it is also reasonable to ignore any cost differences

[11] These capital costs include the modules, direct and indirect balance of plant (BOP), and owner's cost. In particular, the costs include all work and associated costs for furnishing, installing and commissioning the entire PV system. The costs also include the complete engineering, procurement and construction (EPC). The cost range represents several scenarios with different PV module selection (monocrystalline silicon, cadmium telluride thin film), mounting system (single axis tracking vs. fixed), inverter type (central inverter vs. string inverters), and five U.S. locations (Las Vegas, NV; Alamoso, CO; Jacksonville, FL; Columbus, OH; and Charlottesville, VA).

[12] These O&M costs include preventive/schedule maintenance, module cleaning, unscheduled maintenance, inverter maintenance reserve, and other costs. The utility-scale PV O&M cost range represents the same scenarios as for the capital costs but includes no scenarios for different geographic locations.

[13] These capital costs include the modules, direct and indirect balance of plant (BOP), and owner's cost. In particular, the costs include all work and associated costs for furnishing, installing and commissioning the entire PV system. The costs also include the complete engineering, procurement and construction (EPC). The cost range represents several scenarios with different PV module selection (monocrystalline silicon, polycrystalline silicon, cadmium telluride thin film), mounting system (single axis tracking vs. fixed), inverter type (central inverter vs. string inverters), inverter voltage levels (1000V vs. 1500V), and four U.S. locations (Las Vegas, NV; Alamoso, CO; Jacksonville, FL; and Columbus, OH).

[14] These O&M costs include preventive/schedule maintenance, module cleaning, unscheduled maintenance, inverter maintenance reserve, and other costs. The utility-scale PV O&M cost range represents the same scenarios as for the capital costs but includes no scenarios for different geographic locations.

[15] Total cost (EPC & developer) in 2018 $1.46/W$_{DC}$ including modules, inverter, structural/electrical BOS, install labor & equipment, EPC overhead, sale tax, land acquisition, permitting and interconnection fees, developer overhead, contingency, and EPC/developer net profit.

[16] Assumed O&M costs for a one-axis tracker system in 2018.

[17] These capital costs include the modules, inverters, installation, and other balance-of-plant costs (also referred to as soft costs). The capital cost ranges represent a single technology scenario (rooftop-mounted, monocrystalline silicon) for the same five U.S. locations as the utility scale PV system.

[18] A single O&M cost estimate is provided for commercial and residential PV system, each.

between the different PV plus storage configurations (AC-coupled, DC-coupled with monodirectional inverter and DC-coupled with bidirectional inverter) [43], [41].

PV plus storage systems are expected to have lower O&M costs as compared to separately deployed PV systems and energy storage systems. However, there is not enough cost data available to quantify the savings. If O&M costs were considered in NWA screening, it is reasonable to add the O&M costs of corresponding PV and energy storage systems and, if desired, assume some percentage saving in the O&M costs. The same approach can be applied for the decommissioning costs.

Table 4-5
Solar plus storage installed costs [44]

Category	Cost	Description	Scaled for	Source
Energy storage	$462/kWh	Battery modules, battery management system, rack hardware, thermal management system, enclosures, fire detection and suppression	Battery kWh capacity	[36]
AC system, interconnection and control	$308/kW	Inverter, external site controller, transformers, switchgear, switches, protection, auxiliary power supply, and other equipment needed for interconnection (up to high side of step-up transformer)	Inverter kW rating	[36]
PV modules	$470/kW	PV modules only	PV kW_{DC} capacity	[42]
PV EPC and BOS	$840/kW	Engineering, labor, developer profit, PV module racking and wiring	PV kW_{DC} capacity * 0.5 to account for shared ES and PV costs (interconnection transformer and other equipment)	[42]
PV Inverter	$60/kW	Inverter only	Excluded because PV and energy storage share an inverter	[42]

Demand Response Cost Estimates

Demand response program costs can be roughly divided into costs that are specific to each participating customer and costs that are less dependent on the number of participating customers. Both cost categories can be further divided into upfront costs and operational costs.

- **Customer-specific upfront costs** include the costs of deploying the technologies enabling the demand response of customer assets, such as smart thermostats or remote-controlled switches. As these enabling technologies are frequently provided (almost) free of charge to the participating customers), they can be considered as customer-specific upfront costs of the demand response program.
- **Customer-specific operational costs** may include annual or monthly payments (or bill credits) to the participating customers and/or payments for performance ($/kWh).

- Demand response programs typically also include **marketing and customer acquisition costs**. While these costs are not strictly speaking customer-specific, increases in marketing and customer acquisition costs are typically required to reach higher customer participation rates.
- **Other demand response program costs** may also involve other capital or O&M investments related to establishing the necessary utility communication and control infrastructures, etc.

Providing costs or cost ranges for demand response programs can be challenging as the costs can vary based on the utility, rate structure, demand response program type, and many other factors. Depending on the demand response program experience of a given utility, the utility demand response, billing, or other relevant department may already have demand response cost estimates with varying degree of confidence. Table 4-6 lists some example demand response costs to illustrate the magnitude of costs. For NWA screening purposes, it is recommended to use utility-specific demand response costs, if available.

Table 4-6
Demand response program costs

Category	Cost	Source
Residential air-conditioning demand response program	Recruitment costs: $500/customer + customer bill credit: $40/year	[28]
Commercial & Industrial customer demand response program	Bill credit: $25-48/kW/year + $0.40/kWh curtailed energy	[28]
Central Hudson PeakPerks demand response program	Air-conditioning participants: $85 enrollment reward + $50-$100 annual reward depending on participation level (50%-0% cycling during events) Pool pump participants: $85 enrollment reward + $50 annual reward Water heater participants: $25 enrollment reward + $24 annual reward Generator participants: $250 enrollment reward + $250 annual reward	[45]

Screening for Stacked-Services

Some NWA solutions have the potential to provide services beyond the distribution application. In particular, front-of-the-meter (FTM) energy storage systems deployed as a part of a NWA solution have the potential to provide one or more stacked services related to generation, transmission, or distribution domains. Behind-the-meter (BTM) energy storage systems deployed as a part of a NWA solution can additionally provide stacked services related to the customer domain. Table 4-7 summarizes energy storage stacked services related to generation, transmission and distribution domains. A more detailed discussion of energy storage services can be found in [36], [46].

The value of stacked services depends on the service considered, and a myriad of other factors. Hence, it can be challenging to provide useful values or value ranges for the different stacked services. The value of market and customer related stacked services can be estimated with tools such as EPRI's DER-VET [47]. The following criteria can be considered when evaluating the feasibility to provide stacked-services:

- **Availability of stacked distribution or transmission services**: A pre-requisite to provide stacked distribution or transmission services is that there is a need for such services at the same grid location as the NWA distribution grid need. NWA grid needs, which are co-located with stacked distribution or transmission services, may be rare.
- **Wholesale market participation requirements**: Depending on the jurisdiction, NWAs owned and operated by the distribution utility may or may not be able to participate in the wholesale markets. Additionally, many wholesale market services have participation requirements such as minimum kW, minimum duration, certain ramp rate, among others [36]. These requirements are specific to the wholesale market and the market services. FERC Order No. 841 required RTOs and ISOs to reduce the minimum size requirement for electric energy storage resources to 100 kW [48]. Furthermore, when FERC Order No. 2222 becomes effective, it will require RTOs and ISOs to implement a minimum size requirement that does not exceed 100 kW for all DER aggregations (one or multiple DERs) [49]. When effective, FERC Order No. 2222 is expected to help remove minimum size requirement from distribution-connected NWA solutions that tend to be much larger than 100 kW today.

Table 4-7
Distribution, transmission, and wholesale market services

Service Group	Service	Description
Distribution System	Capacity	Avoid/defer distribution capacity investments
	Reliability and resiliency	Increase distribution system reliability and resiliency by allowing islanded operation under system events
	Distribution volt-var control	Support distribution voltage regulation with the storage reactive or active power output
	DER integration / hosting capacity increase	Use ESS to integrate a DER, or increase distribution feeder hosting capacity
	Asset life extension	Extend the life of transformers and other assets by reducing their peak load
	Distribution loss reduction	Reduce distribution losses by reducing transformer and other element loadings
	Power quality	Improve the power quality of a feeder section or a specific customer
	Phase balancing	Reduce the distribution system current and/or voltage unbalance
Transmission System / Generation	Capacity / congestion relief	Avoid/defer transmission capacity investments
	(Dynamic) volt-var support	Provide transmission system (dynamic) reactive power and voltage support in place of conventional alternatives, such as flexible alternating current transmission system (FACTS) devices
	Peaker substitution / peaking capacity	Couple existing peaker units with ESS or use ESS instead of new peaker units
	Blackstart generation and restoration support	Use ESS as a hybrid solution with existing blackstart units, or instead of new blackstart units
Wholesale Market	Energy time-shift / energy arbitrage	Charge during low (or negative) energy prices and discharge during high energy prices
	Flexible ramping	A product in California Independent System Operator (CAISO) real-time market
	Frequency regulation	A product where the ESS follows a frequency regulation signal dispatched every 1-10 seconds depending on the market
	Spinning & non-spinning reserves	A product employed to protect the bulk system against contingencies, particularly unplanned outages of major transmission lines or generators
	Resource adequacy	A product used to provide the reliability requirement of having sufficient generating (and non-generating) resources available to meet the system peak load

5
RELIABILITY SCREENING

NWA solutions can have a positive or a negative impact on the distribution system reliability. NWA solutions solely deployed to increase distribution system reliability or resiliency are expected to increase the system overall reliability. In such cases, it is not necessary to screen for the (adverse) NWA reliability impacts and instead, NWA screening can be focused on the technical feasibility and the economic aspects of the NWA solution. An approach to assess energy storage systems as a NWA to increase distribution system reliability is discussed in [50].

NWA solutions solely deployed for deferring distribution capacity upgrades are likely to have a negative impact on reliability because NWA solutions tend to have lower reliability as compared to conventional wires solutions. The lower expected reliability of NWA solutions originates from the additional failure points that NWA solutions introduce. Moreover, some NWA solutions, such as solutions including demand response programs or pricing schemes, introduce increased human interactions in the operation that may have additional adverse reliability impacts. The scale of the potential negative reliability impacts of NWA solutions is not well understood due to the limited operating and reliability history of NWA solutions as compared to wires solutions. The reliability and expected lifetimes of PV, energy storage, and inverters are discussed in more detail [51], and the performance and reliability of demand response is discussed in [52].

To illustrate the potential negative reliability impact of NWA solutions, consider a NWA solution that provides capacity relief for 100 hours per year with a 97% reliability (3% outage rate per year), will introduce an extra of 3 additional hours per year that some part of the feeder will be in outage. In comparison, a transformer upgrade has essentially the same failure rate as the one it replaces and thus, has a neutral impact to system reliability[19]. The more frequently an NWA solution is relied upon to provide distribution capacity, the higher the probability the NWA will be unable to provide the desired capacity. On the other hand, NWA solutions that are needed infrequently (only few hours of the year) will have only a minor negative impact on the system reliability. The **maximum frequency with which the NWA solution is needed** can be considered as a potential NWA reliability screening criterion. As it can be challenging to identify hard limit for this screening criterion, it may be more suitable to be used as a soft limit or scoring/ranking metric.

NWA solutions may also be deployed to both defer capacity projects and increase distribution reliability. In such scenarios, NWA solutions may either improve or have a neutral impact on the system reliability depending on the NWA capacity, capacity deferral requirements, and size of the island the NWA would serve, etc. These NWA reliability impacts are complicated by the conflicting NWA siting and other design considerations that capacity and reliability applications may have. In reliability applications, NWA solution may need to be located far from the point of

[19] The NWA solution is unlikely to replace the existing transformer. This simplified example ignores, e.g., the typical "bathtub curve" of asset reliability. For details, see [49].

the distribution capacity, potentially beyond a switch to isolate it. In contrast, in capacity deferral applications, the NWA solution may be placed close to the capacity need.

Disaggregation of the NWA solution across multiple devices (e.g. multiple smaller storage devices) has the potential to improve the reliability of the NWA solution (less single points of failure and potential operating states). However, this will likely come at an increased implementation cost as NWA solutions consisting of single assets are likely to have the least cost (ignoring the cost of reliability). The screening of disaggregated NWA solutions should consider both the disaggregation costs and the reliability impacts. A potential approach to screen for disaggregated NWA solutions is as follows. First, centralized NWA solution(s) can be identified and screened with the technical screening criteria discussed in Chapter 3 and economic screening criteria discussed in Chapter 4. Then, reliability screening can be performed for centralized NWA solution(s) that passed technical and economic screening. Last, if reliability screening raises any concerns, disaggregated NWA solutions, which meet technical and reliability requirements, can be identified and screened with the economic criteria.

Minimum NWA Reliability Requirements

A potential NWA reliability screening criterion is to impose minimum reliability requirements for the NWAs, which can be expressed, e.g., as the NWA solution availability[20]. Minimum reliability requirements can be included as a requirement in the NWA RFP or used as a metric in evaluating RFP bid responses. However, the minimum reliability requirement criterion may also eliminate some DER types from consideration altogether. For example, demand response programs based on voluntary customer participation may not be suitable for grid needs with high reliability requirements. As such, minimum NWA reliability requirements should not necessarily be applied as a hard screening criterion given that reliability is often a factor that can be impacted by NWA design. For example, NWA solutions, which include demand response with voluntary customer participation, can be designed to satisfy certain reliability requirements by considering the worst-case customer participation.

The specifics of the NWA grid need should be considered when identifying the minimum NWA reliability requirements. For example, NWA solutions considered for deferring distribution equipment that are a part of the single supply point to loads may be subject to higher reliability requirements than when alternative supply points are available for the loads beyond the deferred/avoided distribution equipment. Moreover, NWA solutions considered for deferring capacity investments that supply critical loads should be subject to higher minimum reliability requirements.

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[20] A resource availability is commonly defined: $total\ uptime/total\ downtime \times 100\%$.

Project Size

A project size screening criterion, which is currently applied in some jurisdictions (see Chapter 2), is employed to avoid considering NWA solutions for deferring distribution capacity needs above a certain threshold, e.g., 20% of the circuit peak load. The project size screening criterion is to limit the scope of outages or other adverse impacts if a NWA solution failed to meet its performance requirements (e.g. an outage or performance below specifications). This screening criterion is expected to be less important as utilities gain more experience and confidence in NWA solutions.

6
OTHER SCREENING

This chapter introduces several miscellaneous NWA screening criteria that do not clearly belong under the technical, economic, or reliability screening categories discussed in Chapters 3-5.

Project Lead Times

Project lead time screening criterion is helpful in identifying whether there is sufficient time available to deploy an NWA project. The initial planning study will determine when a solution is needed, and thus inform the available timeframe for identifying, procuring, and deploying a potential alternative. The lead-time for alternative projects can vary significantly, depending on the scale of the required project. Constraints that are expected in the short-term may not be resolved by a solution that requires longer design, construction, and/or installation lead-times. Developing new programs or pricing schemes that require third party participation and/or regulatory approval may have a longer lead time and be unsuitable for short-term planning needs.

For NWA, there is usually a significant amount of time required for solution procurement and deployment, which can add a degree of uncertainty to the overall lead-time of the project. Once earlier screens have been passed and a utility decides that an NWA is a feasible solution to the distribution constraint, a request for proposals is typically prepared and issued. A sufficient window of time must be allowed for bids to be prepared and submitted. Once that window has closed, the bids must be assessed, and a winning bid selected for application. Contracts must then be negotiated for the winning bid, followed by a full interconnection procedure. In some regions, there is an additional regulatory approval required before the deployment of the solution can begin. All in all, this process can take a significant amount of time, and if the need is pressing, there may not be time to go through it. NWA lead times required may also depend on the lead time of a back-up measure, along the NWA deployment process, particularly if a third-party solution has been identified. Furthermore, if none of the submitted bids meet all of the NWA requirements, then considerable time and effort has been expended that could have been more efficiently spent developing a wires alternative.

While the NWA project lead times can be significant, they are expected to reduce as utilities gain more experience and develop processes to evaluate and deploy NWAs. Eventually, NWA lead times may even become shorter than those of some complex traditional wires solutions.

The following table, Table 6-1, highlights some example lead times and identifies the appropriate deferral approach for each. Lead times used in reviewed U.S. jurisdictions are listed in Table 2-1. As shown in the table, the lead times criteria may depend on the scale and complexity of the grid need. Additionally, NWA lead times may also depend on the NWA technology type. For example, it is likely faster to procure and deploy an energy storage system than to develop a new demand response program, recruit customers, etc.

Table 6-1
Example project lead times and deferral opportunities [24]

Timeframe	Example Project / Equipment Deferral	Deferral Opportunity / Approach
Very Short Term (0-1.5 years)	Needs discovered during operations that must be addressed prior to the next peak season	Potentially insufficient time to source and deploy DERs Would require expedited sourcing and regulatory approval process
Near Term (1.5 – 3 years)	Small thermal capacity needs (e.g. line conductors, small transformers) Voltage/VAR projects (e.g. distribution line capacitors, load tap changers, line voltage regulators)	Limited lead time requires expedited solicitation and regulatory approval process. Due to smaller size and low risk conventional projects, DER solutions might not be cost-effective
Intermediate Term (4 – 5 years)	Large thermal capacity needs (e.g. line conductors, substation upgrades, new circuits) Voltage/VAR projects (e.g. substation capacitors, load tap changers) Reliability (back-tie) (e.g. line conductors, switches)	Procure DER through RFO solicitations in areas with larger attribute requirements Expedited regulatory approval may still be necessary.
Long Term (6 – 10 years)	Projects with long lead times or require licensing activities (e.g. New Substations, New Subtransmission Lines)	Locational net benefits analysis (LNBA) maps signal market participants where DERs may provide grid benefits Proceed to RFO when need is reasonably certain.

The project lead times screening criteria discussed above is intended to identify if sufficient lead time is available for deploying a NWA project. On the other hand, it may be desirable to also consider a maximum project lead times criterion to avoid evaluating NWAs for projects that are very far in the future. Given that the uncertainty associated with load and DER forecast tends to grow with the length of the forecast time horizon, considering NWAs for needs very far in the future risks ending up with stranded assets built for needs that were never realized. For needs very far in the future, it may be desirable to postpone NWA evaluation for later planning cycles. As maximum project lead times criterion is closely related to forecast certainty criterion discussed below, it may not be necessary to consider maximum lead times criterion separately.

Forecast Certainty

Load forecast is a key input that drives the NWA requirements for deferring distribution capacity projects. Among other things, the load forecast will determine the NWA project timing (i.e., when additional distribution capacity is required), what the NWA operational requirements for deferring the distribution capacity are, and what the overloaded distribution assets deferred by NWA projects are. It is crucial to consider the certainty of the load forecast as all load forecasts are subject to some degree of uncertainty [7].

Needs that are more certain should be prioritized over those that are less certain. In practice, this could mean prioritizing, e.g., projects with more stable historical load growth and/or more short-term need. Projects with high load growth also have the risk that the NWA project will only be able to serve the load growth for a short period of time. Similarly, in cases where load growth is driven by customer-specific development, priority should be given to cases where growth is more certain, e.g.:

- Customer submittals for new load vs. external reports of possible future development
- Multiple customer requests for new load, groundbreaking ceremonies, load materializing

An uncertain forecast also presents the risk of stranded assets, which are a key concern for many utilities. For example, if a forecast predicts growth that does not materialize, assets may have been deployed to offset that growth that are now no longer necessary. NWA with short lead times (e.g. portable utility-owned storage) may offer the ability to better account for planning uncertainties by providing temporary load relief and bypassing the risk of stranded assets.

The accuracy of the load forecast also plays a role. Is historical measurement data available for the constrained circuit, or is it necessary to use data from other circuits (availability of SCADA)? In cases where local historical data is available, care should be taken to examine the historical load. The shape of peak load may not be representative of what will occur in the future e.g. very spikey peak load may not re-materialize. On the other hand, it may be possible to address very long peak load times only with limited types of resources. Historical weather patterns are another important consideration when historical load data is being utilized to inform forecasts. Peak loads that could be attributable to abnormal weather conditions such as storms may not be a reliable basis for future load forecasts.

Customer Composition (Customer-Based NWA Solutions)

There are a number of screening criteria, such as the ones listed in Table 6-2, which can be useful for screening customer-based NWA solutions. Customer size and count in the constrained area are among these criteria. It may be desirable to give a higher priority to projects where the load is composed of many large-scale customers, such as commercial or industrial customers, as opposed to projects where the load is composed of a small base of large-scale customers, or a large number of small-scale customers. A large base of large-scale customers provides a wider pool of customers to engage, as well as potential backup options, which a smaller base could not, posing less risk. Large quantities of smaller customers may not be preferable, as the cost of engaging more customers is higher. Customer size and count screening criteria leads to prioritizing projects where the constrained assets serve a high number of customers (e.g., substations or substation transformer banks), as opposed to projects where the constrained assets serve a lower number of customers (e.g. feeder line sections).

In addition to the customer size and count, it may be important to consider further customer characteristics. For example, to consider a NWA solution involving demand response of customer air-conditioners, it is necessary to have sufficiently large number of customers with air-conditioning load. As it is unrealistic to expect all customers to participate in a given program or pricing scheme, it is recommended to consider the projected customer participation rate when evaluating if suitable customer base exists.

It may be more suitable to apply these screening criteria related to customer composition as a soft qualitative criteria or scoring/ranking metrics as opposed to a hard criteria with specific thresholds.

Table 6-2
NWA screening criteria related to customer composition (customer-based NWA solutions for distribution capacity)

Metric	Higher Priority	Lower priority
Customer size and count	Many large customers contributing to the peak load	Few large customers or many small customers contributing to the peak
Customer type	Customers whose load or DER generation is well aligned with the peak load	Customers whose load or DER generation is poorly aligned with the peak load

Technology Readiness Level

Technology readiness level screening criterion is directed for new types of NWA technologies. An example of technology readiness screening criterion is to require all the NWA technologies to have been demonstrated in a pilot project. Technology readiness may be more suitable to use as a soft qualitative criterion or as a prioritization metric as opposed to a hard criterion with a specific threshold.

Distribution Capacity Requirements

In distribution capacity NWA applications, the NWA kW and kWh requirements are driven by the load forecast over the capacity constrained elements. High load growth leads to rapidly growing NWA kW and kWh capacity requirements. Energy storage and many other NWA solutions have a higher cost per added capacity ($/kW and $/kWh) as compared to conventional distribution solutions. On the other hand, energy storage and many other NWA solutions can be deployed more modularly as compared to conventional distribution solutions that tend to require step-sized increments. For example, it may be possible to increase the capacity of energy storage systems much more modularly as compared to substation transformer and distribution feeder conductor types/ratings used by a given utility. As a result, NWA solutions tend to be more suitable for deferring/avoiding distribution capacity when: 1) NWA capacity requirements are limited, 2) circuit load grows moderately, and 3) conventional distribution solutions available have larger step-sized increments compared to the capacity need. These three aspects could be leveraged to screen or prioritize distribution capacity projects more suitable for NWA solutions.

Feeder Characteristics

The characterization of the feeder that is constrained can provide a type of NWA screen. Rural feeders may be more suitable for DER-based NWAs such as PV or storage given that they are often quite lengthy, at times stretching over rough terrain, which can make deployment of certain traditional alternatives both difficult and expensive. Growth scenarios for rural areas may also be better aligned with NWAs. Furthermore, it is much more likely that there is significant land available for large DER deployments. On the other hand, more urban feeders that are shorter in length, serve larger numbers of customers and have limited land availability may be better candidates for NWAs such as demand response.

Screening of Third-Party NWA Solutions

Sourcing NWA solutions from third parties is encouraged or even required in some jurisdictions due higher perceived cost-efficiency. It may also be voluntary when utility in-house experience is limited. NWA screening can have different flavors under third-party sourcing. Figure 6-1 illustrates the screening and evaluation of utility-owned/operated NWAs and third-party provided NWAs. Third-party provided NWAs are frequently procured through competitive solicitations that involve preparing a request for proposal (RFP) and evaluating the bids received as responses for the RPF. Current NWA evaluation processes commonly involve two RFP bid evaluation stages: 1) Pre-qualification stage, and 2) Detailed assessment stage. Each of the two stages can involve evaluating the bids against quantitative and/or qualitative metrics, such as the ones listed in Table 6-3. The pre-qualification stage can be considered as a form of NWA screening. For more details on sourcing NWA solutions from third parties, see [53].

In some jurisdictions, e.g. California, partial responses to the NWA RFPs are allowed requiring either the utility or an external aggregator to identify an optimal portfolio of bids to meet the NWA grid need. Different criteria and methods may be required to screen portfolios of NWAs.

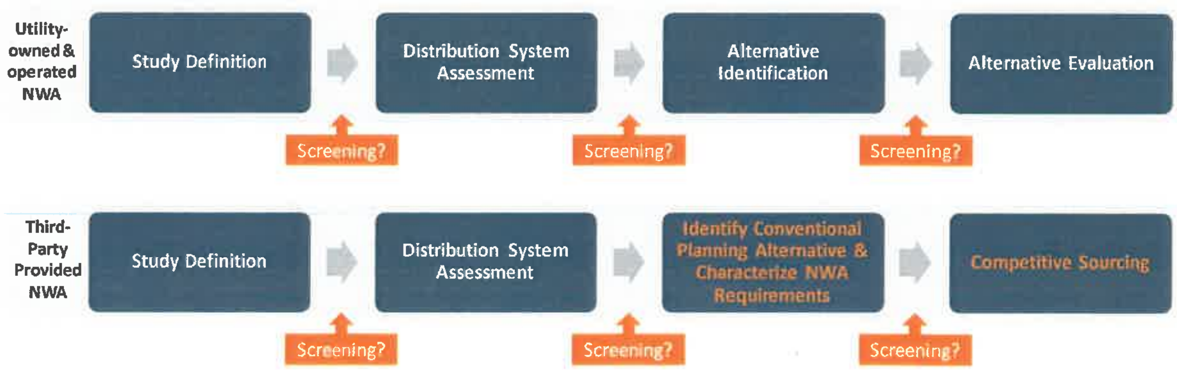

Figure 6-1
Economic screening of third-party NWA solutions [4], [2], [53]

Table 6-3
Third-party NWA solution RFP evaluation metrics

Quantitative	Qualitative (*with possible scoring system*)	
• Compliance with technical requirements • Price bid • Cost efficiency	• Technology readiness • Provider experience • Project financial viability • Financial strength of provider • Contractual exceptions	• Customer acquisition strategy (BTM) • Community outreach and support (FTM) • Site control (FTM) • Interconnection cost and lead time (FTM)

7
SUMMARY AND NEXT STEPS

Summary

NWAs undoubtedly add more complexity to the distribution planning process, due to the significant time and effort associated with detailed NWA identification and evaluation. Screening methods and criteria can provide a means of simplifying the integration of NWAs into distribution planning by determining at various stages of the planning process whether it is sensible to proceed with more detailed assessment of an NWA solution. Table 7-1 lays out the various screening criteria that have been discussed throughout this report, as well as a preliminary mapping to planning process steps. As discussed in Chapter 1, it is likely that the existing planning steps will be followed to first identify a traditional solution, which can be used as a benchmark for many of the described screening criteria so that planning steps are only repeated for feasible NWA solutions. Once a traditional solution has been established, many of the screening criteria, including project type feasibility, minimum project cost and project lead times, can then be applied prior to the alternative identification step of the planning process. Within the alternative identification step, it is proposed to include screens such as resource availability, siting and customer composition. The simplified cost benefit screen would be recommended before a full cost benefit analysis in the alternative evaluation step.

Next Steps

The research described in this report is the beginning of a multi-year effort examining screening of NWAs. While this report has helped provide insights into current industry practices and considerations, derived novel screening criteria, and provided guidance on their application within distribution planning, there are additional research questions that require further exploration.

Although many screening criteria have been described in this report, there is additional scope for development of screening methods. Future work will leverage the learnings around screening criteria to inform and develop new methodologies to make the screening process more efficient. Additionally, screening criteria for employing combinations of DER as part of an NWA portfolio will be examined, along with screening comparisons for different NWA types e.g. DER solutions vs. programs vs. pricing schemes.

From an economics perspective, a more detailed review of costs and cost ranges for NWA technologies such as demand response programs, energy efficiency programs, and other types of DER would be beneficial. Guidance on screening for potential market services for NWAs, in particular energy storage, will be an important addition to economic screening, particularly in the wake of FERC Order No. 2222.

Screening criteria for reliability and resiliency applications are somewhat undefined at present. Additional system assessment may provide metrics that can be employed as screening criteria, however further research is required to determine whether viable screening criteria exist. This may also be the case for some other NWA applications that have not been discussed in this report. Reliability screening may be captured within economic screens by translating reliability metrics into costs e.g. costs of outages. There are existing tools [54] available for making such conversions, which could be used as part of a simplified cost benefit screen. This will be an area of focus for future work.

Finally, additional research is required in the area of screening for third party NWAs. Once a utility receives responses to an RFP, screening criteria and methods could be employed to simplify the evaluation and selection process. Guidance around the information required within the RFP and the types of screening that may apply is required. Last, guidance around screening NWA solutions combined (by the utility or external aggregator) from multiple partial RFP responses (e.g. RFP responses bidding for a part of the distribution capacity needed) is required.

Table 7-1
Screening criteria and proposed planning process mapping

Screening Type	Screening Criteria	Planning process mapping
Technical Screening	Project type feasibility	Before alternative identification
	Mapping of NWA resource types and applications	Before alternative identification
	NWA resource availability	Within alternative identification
	NWA siting	Within alternative identification
Economic Screening	Minimum project cost	Before alternative identification
	Minimum deferral value	Before alternative identification
	Minimum/maximum deferral time period	Before alternative identification
	Simplified cost-benefit analysis	Within alternative evaluation
	Availability of stacked distribution or transmission services	Within alternative evaluation
	Wholesale market participation requirements	Within alternative evaluation
Reliability Screening	Maximum frequency of NWA solution need	Before alternative identification
	Minimum NWA reliability requirements	Before alternative identification
	Project size	Before alternative identification
Other Screening	Project lead times	Before alternative identification
	Forecast certainty	Before alternative identification
	Customer composition (customer-based NWA solutions)	Within alternative identification
	Technology readiness level	Before alternative identification
	Distribution capacity requirements	Before alternative identification
	Feeder characteristics	Before alternative identification

8
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Modernizing Distribution Planning: Drivers and Future Vision

White Paper — *Distribution Operations and Planning*

The distribution landscape is rapidly changing—introducing new opportunities along with increasing system complexity and uncertainty. This changing landscape is driven by the obligation to accommodate and aim to integrate distributed energy resources (DER), changing load patterns, increased stakeholder engagement in the development and application of planning processes, and increased monitoring, automation and control of the distribution system.

Distribution planning is critical to realizing this modern distribution system. However, traditional planning tools, methodologies, and processes only address a narrow piece of these emerging planning demands. For example, existing processes and tools are more geared towards addressing peak demand only and focused on traditional grid upgrade options (transformers, conductor, etc.) rather than considering new solutions like non-wires alternatives (e.g., DER).

Additionally, today's planning processes do not address time and locational values needed to appropriately consider new technologies and customer resources. Planning methodologies and processes are also not equipped to perform strategic and system-wide analyses to support today's integrated resource planning objectives. Applying traditional planning solutions to address these gaps will be manually intensive given new complexities associated with advanced planning needs.

In order to design the distribution system to meet future needs, planning processes and tools must evolve. New processes and tools with built-in automation capabilities are necessary to meet the challenges of planning tomorrow's distribution system. Future tools must provide a comprehensive, efficient, flexible, and integrated approach.

To meet this need, EPRI initiated a research project to develop, test, and demonstrate new methods and tools to efficiently and effectively perform distribution planning assessments and support holistic decision-making [1]. The first step was to work with utilities from across the globe to understand evolving and future needs and challenges with planning a modern distribution system. This paper summarizes those requirements and gaps and provides a vision for addressing them. This is the first in a series of white papers that will provide a roadmap for advancing distribution planning processes and tool capabilities for the modern grid. Specific drivers, objectives, and capabilities will inherently vary from utility to utility. These white papers are intended to be complimentary and inform modernization efforts and distribution planning roadmaps.

DRIVERs and Capabilities to Modernize Distribution Planning

Established tools and methods for the conventional distribution system enabled the effective and efficient design of robust electric distribution systems across the globe which have served both industry and society well. However, the rapid evolution and adoption of emerging technologies and resources are altering how distribution systems are designed, operate, and are expected to perform under future conditions. These changes introduce new dynamics, complexities, and assessment requirements that traditional planning tools were not intended to address.

This section reviews key characteristics of the modern distribution system and how they are driving the need for new planning tools and capabilities. Understanding these needs is an important first step to ensure the developed methods and tools appropriately address and support planning analyses for the modern distribution grid.

DER Accommodation and Integration

In many aspects, the interconnection and integration of DER represents the most significant change associated with the modern distribution system. In this paper, DER encapsulates the various forms of distributed renewable and non-renewable generation sources, demand-side management, and energy storage devices. DER influence on planning can be viewed from two overarching perspectives, depending on their characteristics and the driver(s) for their grid connection:

1. As resources that may require mitigation associated with accommodating at the distribution level
2. As resources that can be integrated into the distribution system as alternative solutions to traditional distribution upgrade

Not all DER fall cleanly into one category or the other, however. From a distribution planning standpoint there is a spectrum between fully accommodating and fully integrating DER, as shown in Figure 1. The influence of the utility on site guidance, control, and visibility of a particular resource determines where on the spectrum that resource will lie. Organic growth of customer-driven PV, for example, where the utility has no visibility or control of, would lie on the accommodating end of the spectrum shown by the red arrow. A utility-owned, installed, and controlled solution would lie on the integrating end of the spectrum, as shown by the blue arrow. A distribution connected storage system whose primary service is to provide frequency response for the transmission system, but that the distribution utility has visibility of, would need to be accommodated at the distribution level. But the distribution utility having visibility means that the resource would lie slightly towards the integration end of the spectrum, where the yellow arrow is located.

Depending whether DERs are being accommodated or integrated, they are accounted for at different points in the overall distribution planning process. The integration of DER, as a non-wires alternative, is examined further in the next section. The general need to accommodate DER drives several new capabilities, including:

- Near and long-term forecasts capturing potential DER adoption rates and locations, which may occur organically or through utility or third-party incentives.
- Assessments of future load and generation temporal interactions and scenarios needed to inform robust system designs.
- Analytical studies, such as hosting capacity, to assess the system's ability to accommodate additional DER and where system constraints might occur.

Non-Wire Alternative (NWA) Design and Evaluation

DER may also be evaluated as potential NWA. NWA are utility-driven solutions to an identified distribution constraint that defers or eliminates the need for a traditional distribution upgrade [2]. When considered as a potential solution to meet near-term expansion planning needs, NWA are introduced in the planning process once system constraints requiring mitigation have been identified. NWA solutions may also need to be captured in the forecast depending upon the nature of the implementation and controls. This will be examined further when discussing the influences of advanced controls.

Traditional planning alternatives are generally passive in nature. That is, their deployment strengthens or increases grid capacity, and that additional capacity does not change over time, see Figure 2. In contrast, NWA are active and more complex solutions designed and managed to reduce or limit net system demands below existing capacity constraints, as illustrated in Figure 3, to adjust or defer major infrastructure investments. As a result, NWA introduce additional assessment and design requirements within the planning process beyond those needed for traditional mitigation solutions. In particular, NWA solutions cannot be designed and evaluated considering peak demand alone. They must be designed and evaluated considering daily and seasonal variations in demand, as well as other system needs. Note that the example solution presented in Figure 3 does not successfully mitigate the winter capacity constraint. Additional uncertainties regarding the availability and variability of different DER types and dispatch schemes is another important consideration. Furthermore, any additional operations of the NWA solution to provide benefits to other parts of electrical system must also be accounted for.

In many cases, identification of potential NWA solutions requires performing quasi-static time-series (QSTS) simulations, which simulate the response of the solution across a series of sequential points in time [3].

These simulations require examinations of specific time-series profiles for the variation of load and existing generation for relevant study periods. Additionally, system models must be updated to reflect the operation of regulators, switched capacitor banks, and other existing system controls that influence the grid behavior over time. Furthermore, as DER technologies continue to evolve at a rapid pace, the availability of accurate and validated DER models for incorporation within planning studies is a constant evolving challenge.

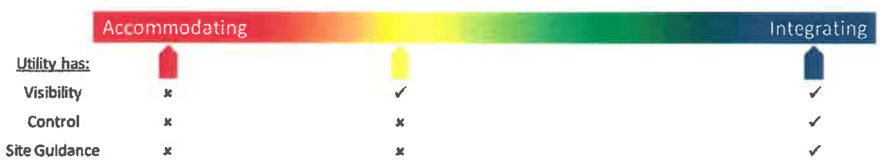

Figure 1 – Spectrum between integrating and accommodating DER

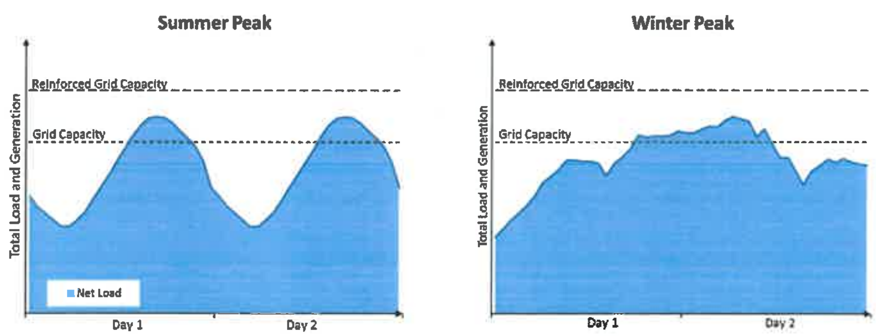

Figure 2 – Illustration of how tradition reinforcements address constraints by increasing system capacity

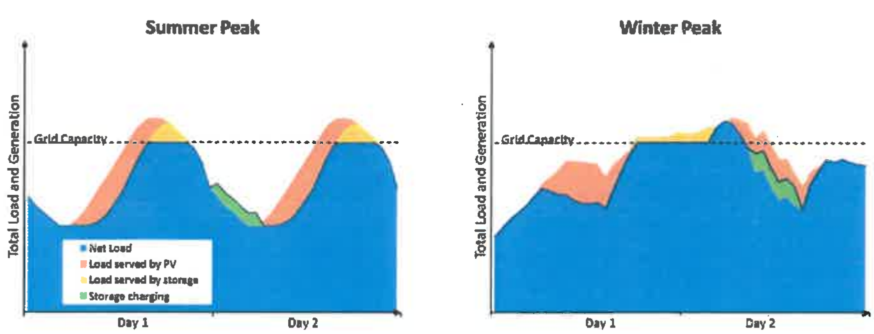

Figure 3 Illustration of how of non-wires alternatives to address system capacity constraints

NWAs potentially offer planners increased options and flexibility in their design and operation as a planning criteria violation solution. While this flexibility is a positive aspect of NWA, it also represents a significant effort on the planner's part to design and validate solutions comprised of various DER types and combinations, potential locations in the distribution system, as well as various ways of controlling or dispatching these resources. Each variation and combination of these factors represents a different alternative that must be appropriately designed and evaluated. Manual evaluation of potential NWA options would translate to a significant burden on distribution planning resources. As such, new methods and processes are needed to ensure the design and validation of NWA is both efficient and effective.

NWAs also introduce new dynamics to planning horizon timeframes, impacting both the design and evaluation of these potential alternatives to traditional solutions. One primary application of NWA is to defer the need for traditional system upgrades. Here the planner must evaluate the value of the deferment and cost of the NWA against the cost of the traditional upgrade. Other considerations such as future land availability and project lead-times also need to be considered. These evaluations are further complicated by the modularity of most NWA solutions that permit them to be upgraded or enhanced over time. This raises the issue of comparing different NWA deployment options considering aspects such as installation costs or possible revenues from providing benefits to other parts of the system.

Comparison of NWA and traditional solutions on an equivalent economic basis must also account for vast differences in useful lifetimes. While conventional assets may be expected to be in operation 30 years or more, power-electronics, batteries, and other components have much shorter lifetimes. Further complexity is added when considering that the cost of various hardware solutions may escalate over time at vastly different rates. The cost of battery storage and solar photovoltaics are expected to continue declining significantly in price, while the cost of conventional distribution equipment is much more stable in real terms. Methods for economic analysis can deal with these differences, but a variety of cost-escalation paths can render counterintuitive results.

In order to fully incorporate NWA within planning, specific capabilities are needed:

- Models and simulations to assess system performance and characterize the power and energy constraints during system peaks and longer periods.
- Automated tools that can quickly identify potential NWA designs and verify each solutions viability under multiple system conditions.
- Economic evaluations that holistically compare all alternative costs and benefits, accounting for differences in asset lifetimes, additional value streams, and other new considerations.

Leveraging New Data Streams

Another key characteristic of the modern distribution system, with a significant influence on system planning, is the higher degree of controllability and visibility, compared to what has been historically available. Expanding system visibility, through increased deployment of smart meters and monitoring, can benefit distribution planning in the form of more accurate system models and improved understanding of how system behaviors and needs are changing. But, realizing these benefits can be challenging and requires planning use cases be factored into the decision making on the types and accuracy of the new data collected. Once collected, having the processes, tools, and analytics in place is critical to be able to leverage these data streams in planning.

The need for improved visibility in planning is becoming even more essential when integrating DER. In some cases, smart meters offer the potential to refine existing feeder models to better represent the system assets that connect individual customers, namely secondary transformers and lines at low voltage levels in near real time. Representing this portion of the system was not a concern when planning the traditional grid, as this was effectively captured through the fit-and-forget approach—given the relatively low costs of these assets and static nature of individual customer peak demands. Thus, for many utilities these assets are not included in system models today. With DER, this is changing and requires a closer look.

However, this visibility is not available everywhere presenting challenges in representing emerging technologies where limited historical data is available. Net metering also presents challenges, hindering the ability to confidently separate DER output and load, masking load and thus complicating the planner's ability to generate planning scenarios that properly account for the temporal variations of each.

In order to realize the benefits of these new data streams in planning, there are specific capabilities needed:

- Guidance on what data is required to inform planning decisions.
- Data management practices that ensure effective maintenance and population of GIS information needed to support planners in quickly updating or generating accurate planning models.
- Data storage and processing capabilities that can handle massive amounts of measurements and locational information, which planners can readily leverage to inform planning models and scenarios.
- Robust analytical methods and tools that can remove measurement errors and reconcile deviations from "system normal", such as those due to operator switching or automated system reconfiguration.
- Derivation of appropriate time-series profiles that appropriately capture hourly and seasonal variations in load and DER output and can serve as the basis for QSTS planning studies.

Advanced System and Resource Controls

Advanced system operational controls, such as advanced distribution management systems (ADMS) and distributed energy resources management systems (DERMS), provide numerous functional capabilities and advanced applications that can greatly improve the operation and reliability of the system. However, these advanced control systems do not reduce or eliminate the need for planning. In fact, planning and operations groups will need to work even more closely to ensure the future system upgrades and expansion efforts consider these controls, optimize their benefits, and even expand their deployment in response to changing system needs and demands.

One key aspect, needed to support this future includes the derivation of forecasts and accurate models for relevant control functions and applications, which may influence planning decisions on future system designs and needs. This includes data management to store, update, and disseminate control setting information currently being used in the field, and the ability of planners to evaluate and propose new settings for certain controls that may mitigate issues or strengthen the system. In many cases, existing DMS and other system controls are not explicitly modeled. When performing traditional peak planning studies, the system controls were often represented by manual intervention from planners, setting the state or status of individual system assets to emulate the system control operation for a particular scenario. However, when emulating complex control schemes, this practice can be cumbersome leading to errors and is impractical to perform if QSTS simulations are required.

Deployment of new system controls can also be evaluated as potential NWA. For instance, an electric vehicle charging system's capital and operational costs can be compared against those deferred or offset in the traditional system expansions needed to serve the electric vehicle charging demands. Depending upon how the control operates, planning studies may need to capture these operations in terms of different planning scenarios or through direct modeling of dispatched control signals and logic.

A highly reconfigurable system during contingency events, and even normal operating conditions, is an important attribute of the modern distribution system. Given the potential for two-way flows of power due to injections from various points along the distribution feeder, changes to the system configuration may result in unexpected system impacts that traditional planning approaches may not sufficiently capture. As a result, the number of planning cases needing to be simulated and evaluated can dramatically increase as a function of DER interconnections and system reconfigurability.

In order to account for and incorporate these new controls into planning, specific capabilities needed include:

- Verified models for control schemes that can impact planning simulation results or benefit from planning studies designed to inform control system rollout or determination of control settings.
- Analytics that can quickly assess system-wide benefits of different control implementations to inform strategic planning effort or as potential non-wires alternatives.

Evolving Planning Criteria and Objectives

The desired performance of the distribution system is evolving as well. However, it is unclear how planning criteria will need to evolve to account for changing system characteristics and industry and regulatory objectives. Furthermore, it's difficult to determine the extent to which changes in planning criteria or objectives would impact system expansion plans and capital expenditures.

Identified planning needs and capabilities that will support modernization of the distribution system include:

- Clear, appropriate, and quantifiable metrics for evolving system objectives such as system flexibility and resiliency.
- Ability to effectively and efficiently evaluate the influence that new or altered metrics would have on system performance and capital expenditures in order to ensure they are beneficial to all parties.
- Methods for incorporating stacked benefits and resource implementation objectives, such as greenhouse gas reduction targets, within technical and economic studies.
- Robust risk assessment and predictive reliability assessment tools that can capture changing system objectives and other planning uncertainties.

Distribution planning tools will not only need to support the objectives and criteria at the distribution level, but also support coordination and information exchange between generation, transmission, distribution, and customers. While the objectives of integrated planning will vary depending on utility structure, existing practices, and regulatory aspects, the distribution planning process is most impacted due to the degree of change. In order to inform generation and transmission planning, distribution planning studies are required on a much larger scale, requiring analysis of hundreds or thousands of distribution feeders, across multiple years and planning horizons not typically performed today. Supporting integrated planning, using the traditional methods and approaches, would be highly resource intensive.

Increased Customer and Stakeholder Engagement

In many states, regulatory and stakeholder processes are underway to influence the development of new distribution planning processes that better consider DER integration. These processes include new requirements for distribution planners to communicate the distribution planning process, analytics, and decisions to a broad set of stakeholders. Planning will also need tools to support stakeholder understanding and visibility in distribution planning decisions. With these requirements, future planning processes and tools will not only need to enable efficient technical assessments and economic evaluations but also provide results that are easily digestible and comparable across a range of factors. Planning tool capabilities that support this objective include:

- Simulation and analytics to produce standard as well evolving metrics regarding the technical performance and economic costbefits of different system reinforcement alternative.
- Ability to quickly introduce new emerging technologies and third-party solutions into the technical assessments and evaluations.
- Tables and visualizations that allow planners to readily document and easily communicate planning study results to both internal and external stakeholders, considering a wide range of alternatives and complex issues.

These capabilities not only support efficient use of available planning department resources, but more importantly, support effective stakeholder engagements through increased transparency and understanding of planning decisions.

The Distribution System Planning Process of the Future (Vision)

Each of these drivers point to specific capabilities that are required within the planning process representing increases in complexity and time to perform planning studies in the future. While currently planning tools may have the ability to be used for certain components of these analytics, new capabilities must be developed to comprehensively plan and design a system, factoring in all these complexities, in an efficient manner.

Review of the drivers and gaps by utility members indicated the following vision for the key features and capabilities for modern a distribution system planning process:

- Holistic evaluation of traditional and non-wires alternatives.
- Flexibility to incorporate changing planning objectives and criteria.
- Engineering analysis that supports effective and efficient system planning.
- Seamless integration of existing and emerging data sources.
- Supports integrated system planning needs between generation, transmission, distribution, and customers.

This process depicted in Figure 4 describes steps of the planning process that will be required in the future. Some of these steps exist today but may be smaller in scale, while others are new steps required for considerations of new resources. New analytics must be developed to characterize various alternatives, optimize their use, and compare them to traditional alternatives effectively.

A major requirement to realizing this vision is the development of tools and analytics that automate various steps of the planning process. As noted previously, the complexities introduced by a more modern distribution system are not easily addressed using traditional planning methods and tools. However, this does not equate to the automation of the entire planning process. On the contrary, many aspects of the planning process cannot be reasonably automated. Furthermore, automation can neither replace the planning engineer's experience and knowledge of the system nor introduce extraneous factors not captured by simulations or analytics. Instead, the planner should have the ability to engineer the appropriate automated analytics and simulations, to more effectively and efficiently answer planning study needs and objectives.

Gaps to Get There

By identifying the drivers, capabilities, and future vision, this white paper is a first in a series of white papers outlining the roadmap forward on future tools and methods to support planners in designing the modern distribution system. The changes are not trivial and require advancements in all areas of the planning process in order to fill the gaps that exist.

In parallel with the roadmap, EPRI is also developing the automated distribution assessment platform and tools "ADAPT" toolset. The purpose of ADAPT is to support research, development, and testing of new methods for automating the planning process steps diagramed in Figure 4.

Applications of the ADAPT toolset will be highlighted in subsequent white papers, which further outline the roadmap and delve further into key aspects of the capabilities required for the modern distribution planning process—such as:

1. Data and modeling needs.
2. Alternative design and assessment.
3. Economic and cost-benefit assessment.
4. User interface and reporting.

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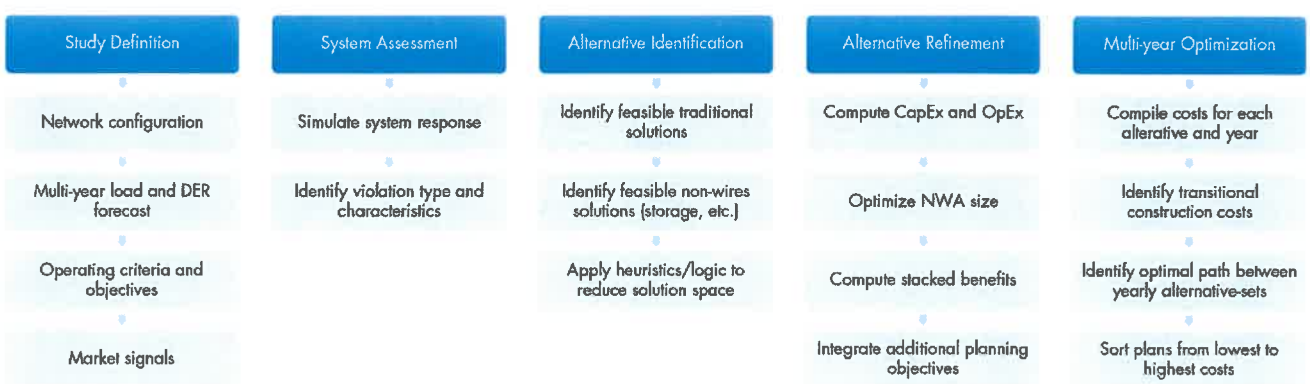

Figure 4 – Steps to the future distribution planning process

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The Value of "DER" to "D":
The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability

Susan F. Tierney, Ph.D.
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March 30, 2016

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Analysis Group

Executive Summary

Transformational are changes occurring in many local electric systems in places as diverse as Hawaii, California, Colorado, Minnesota, Georgia, New York, and Washington, D.C. Solar panels on rooftops are the most visible manifestation of these new distributed energy resources ("DER"). Much has been written about solar panels and other types of DER and the values they bring to customers and to the electric system alike.

This paper focuses primarily on two essential questions relating to DERs: How should utility regulators, distribution utilities and other stakeholders think about the value of DER to *the distribution system* ("The Value of DER to D")? And what are the implications for distribution-system planning, DER procurement and DER compensation that result from those interactions between DERs and the local distribution system?

Regulators, utilities, DER providers, and other stakeholders are working hard around the country to refine methodologies for evaluating when and where DER installations might provide net benefits to the electric system. Although intended to contribute to this broader set of discussions, this report shines a light on some of the policy topics and technical developments relating to the "Value of DER for D." The report illustrates some of the issues and insights by examining developments and analyses underway at two electric utility distribution utilities – Consolidated Edison ("Con Edison") in New York City and Southern California Edison ("SCE") in California. Their distribution systems are very different, yet both companies are actively examining how DERs can become better integrated into traditional distribution-system planning processes so that utilities can leverage these DERs And both utility companies are engaged in state regulatory proceedings affecting the evolving relationships between DER providers and the local utility.

This report highlights the following points:

- **DERs are proliferating across the US mainly due to policies aimed at higher levels of renewable portfolios with incentives tied to that deployment.** Net energy metering has been helpful in fostering rapid adoption of certain DERs (notably rooftop solar technologies), but it is increasingly seen as a rather blunt and imprecise pricing instrument that may not accurately reflect: the value of DERs to the electric system and its constituent parts (the power generation system ("G"), the high-voltage transmission system ("T"), and the distribution system ("D")); and separately, the external value of DER to society ('S").

- **Different DER technologies have different attributes and different impacts on and contributions to the electric system.** Studies indicate the Value of DER to D is typically small relative to the Value of DER to G, T or S. Most distribution-related avoidable costs are tied to deferred capital investments. Analysis conducted by the Electric Power Research Institute ("EPRI") on behalf of SCE and Con Edison confirms that the value of DERs to D depends on their location on the local grid and upon those DERs having characteristics that provide the needed characteristics of availability, dependability, and durability (sustainable supply). Analyses of Con Edison's local network, for example, indicate that the ability of DERs to resolve reliability violations on the local grid decreases substantially as the DERs' physical distance from a local reliability problem increases.

- **Conceptual frameworks for valuing DERs will need to evolve in order to better determine the value of DER to D.** Typically, valuation frameworks (such as those used to evaluate energy-efficiency programs via benefit/costs tests) show the potential for DERs to be net-beneficial, but they only go part of the way to identifying which DERs actually contribute value to D. Determining the value of a particular set of DER technologies/applications in specific distribution-system contexts will end up being much-more complex and difficult to execute than the typical simplified accounting frameworks might suggest because of the location-specific impacts of DERs with different attributes. At least for DERs designed to compete with traditional utility investments within the distribution-system resource planning process, valuation should move beyond the initial screen, which examines potential benefits, to more location-based analyses that focus on both expected and actual performance of DERs in identifying cost-effective substitutes for traditional D (and for T, and G) solutions.

- **New methods for Valuing DERs for D should be built on the timeless regulatory principles of efficiency and fairness so as to create value for all customers on the distribution system.** As part of the constructive attention being given to how DERs might play larger roles in the future of the electric system, the principles of fairness and efficiency remain important in considering cost-allocation and compensation levels for DERs and in developing ratemaking mechanisms for utilities. Doing so increases the opportunities for DERs to be incorporated in ways that create value for all customers on the local system.

- **Utilities should integrate DERs into their distribution-system planning processes so that DERs have the potential to substitute for traditional utility investments where they can provide needed attributes cost-effectively.** Most traditional fixes for anticipated local reliability problems are capital investments, many of which have long lead times. These lead times are taken into account in the utility's planning horizon and involve physical upgrades to reinforce the capability of the infrastructure to meet customers' electrical requirements. This suggests that at least in the early stages of the evolution, the integration of DERs into distribution-system planning and plans ought to focus on ensuring that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide equivalent functionality as would have been provided by a traditional solution.

- **Prior PURPA experience teaches us that market-based mechanisms led to greater value to customers compared to arrangements in which alternative power producers were paid administratively determined avoided costs.** Where the utility can fairly obtain and efficiently pay for the quantity/timing/location of DERs needed at market-based competitive prices (rather than at avoided cost), then DERs can provide net benefits – i.e., value to the system and its customers. Many states' experience in implementing the Public Utility Regulatory Policies Act indicates that customers benefitted when the industry transitioned away from initial approaches that relied on administratively determined prices. This experience offers important lessons for the current efforts to design methods to integrate DERs efficiently and effectively into distribution-utility plans and operations, and to do so in ways that balance value to all customers with compensation to DER suppliers. Competitive solicitations can reveal the portfolio of DERs with the attributes to satisfy the utility's local reliability requirements at lowest cost. The utility can then enter into contracts to assure that those DERs enter the market and help to resolve local reliability problems cost-effectively and reliably. Periodic procurements would also be able to take into account the changes that inevitably occur on the distribution system over time, with some changes pushing out the date of need and others leading to earlier reliability challenges than previously anticipated.

- **Forward contracting for DER capacity should be the focus of early-stage market developments related to DER for D.** Given that the lion's share of potentially avoidable distribution costs are capital investments, it seems important to focus initial market-design attention on procuring DERs for their capacity value to distribution systems over specific periods of time. In the future, as the markets for DER evolve, it may be worthwhile to look at the other shorter-term/ operational sources of value of DER to D, and then refine shorter-term/operational/transactional markets to compensate contracted resources for performance and for other services provided by DER to D. After the main source of value (distribution capacity) is realized, then these other value streams can be layered on top of that foundation. This prioritization of "DER-for-D" market elements – starting with a focus on forward procurements of capacity as the main event, and then moving toward more secondary and likely smaller transactional markets over time – fits with economic principles about the conditions that enable robust, successful markets to exist.

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The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability

Susan F. Tierney, Ph.D.[1]
Analysis Group

Introduction

Setting the stage for distributed energy resources

Big changes are underway in the power system. Headlines have captured the important role of relatively low-cost natural gas for power production, the rapid growth in wind and solar energy capacity, and the impacts of federal environmental policies. Competitive power markets have enabled many new players and technologies to break into the industry.

Equally transformative are changes occurring in many local electric distribution systems and on customers' own premises. These changes are showing up in places as diverse as Hawaii, California, Colorado, Minnesota, Georgia, New York, and Washington, D.C. Solar panels on rooftops are becoming more common. For a variety of reasons, large and small electricity users are taking steps to directly manage their own energy supply. This transition anticipates an increasingly customer-driven and decentralized electric system.

Distributed Energy Resources ("DERs"): Defined

People mean different things when they refer to "DERs." This particular report adopts a very-broad definition which includes relatively small-scale technologies (e.g., solar photovoltaics ("PV"); wind; storage; combined heat and power ("CHP"); micro turbines; demand-control systems; and energy efficiency) that either located "behind-the-meter" on a customer's premises (and operated for the purpose of supplying all or a portion of the customer's electric load), or connected directly to the distribution system for local reliability.

Much has been written about these new trends in DERs[2] and the values they bring to customers and to the system alike.[3] From a regulatory policy and economic point of view, there are important distinctions to be drawn between: the value of DERs to the customers who install them; the value of distribution service to those customers; and the value of DERs to the entire electric system (and therefore to all customers). Often the distinctions are blurred.

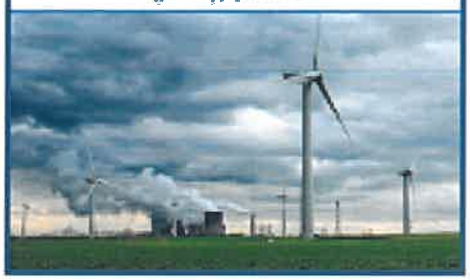
This paper examines the issues from one particular vantage point: What is the value of distributed energy resources *to the distribution system*? Stated otherwise: What is the Value of "DER" to "D"?

To put that question in context, Figure 1 presents the various lenses through which these issues tend to be viewed. As shown in Figure 1, here are the distinctions:

Retail electricity customer
using DER for self-supply when available, injecting power into the distribution system when there's surplus DER power, and/or drawing power from the grid when the DER is not available

Electric Distribution Utility
providing wires/distribution service to DER customers with surplus power to be delivered to other customers, relying on DER to avoid other costs on its local system, and providing wires service to all other customers (either on unbundled basis or as part of bundled retail electric service to the retail customer)

Utility-Scale Generation and Transmission,
providing power delivered via high-voltage lines (either on unbundled basis or as part of bundled retail electric service to the customer), with lower loads and higher supply due to DER



External Impacts,
with DER imposing negative and/or positive impacts on other things beyond the purchase and sale / production and consumption of electricity.

Figure 1

D and DER: The Value of What to Whom?

There are active discussions going on around the country with regard to the value of electricity to consumers, the value of DER to customers and to the system, and the value afforded to consumers with DER by virtue of being interconnected with the grid. Too often, these concepts get comingled.

A. *The "Value of D"*: the value a retail electricity customer places on the grid (either to get bundled electricity service through the distribution utility, or to use the distribution wires on an unbundled basis to get access to the wider electricity system so that the customer can have power supply on demand and/or inject surplus power from on-premises DER for use by other customers).

B. *The "Value of DER" to the electric system:* the cost net savings that result from having a specific DER (or portfolio of DER) in place, as compared to the costs associated with investing in and operating to the electric system in the absence of those DERs.

C. *The value of DER to the participating customer*: the array of net benefits that the customer having DER on his/her premises receives from doing so. Benefits might include: satisfaction of various objectives such as: improved customer service; lower environmental impacts resulting from energy use; potential hedges against price increases; ability to better manage energy price increases; increased sense of energy autonomy; potential resiliency improvements; and so forth. These benefits may or may not offset any up-front and/or on-going costs facing the customer that adopts DER.

D. *The value of DER to the local community / society*: the net impacts of DER deployment that go beyond the electric system and the producers and consumers of electricity. These impacts include lower (or higher) overall air emissions and water use, higher or lower local employment, transfer of dollars into or out of the local economy.

A. *The "Value of D"* is the value a retail electricity customer places on being connected to the grid. The wires allow the customer to receive bundled or unbundled electricity service through the distribution utility, or to use the distribution wires for access to the wider electricity system. For the latter, the customer may be injecting surplus power from on-premises DERs to supply power to other customers whenever that power is available and/or to provide grid services at the distribution or transmission level.

- Under traditional cost-of-service utility regulation, the "Value of D" to the customer is reflected in the distribution charge on the customer's bill. Distribution charges are one component of the local utility's electricity rate and typically reflect that customer's allocated share of the distribution utility's cost of service. These costs can be recovered through a wide combination of fixed and variable charges, differing by customer type, by utility and by regulatory policy.

- The Value of D is not the same as the full electricity price (which reflects transmission and generation and other related costs that go beyond distribution service, and typically also includes various taxes and fees). These other charges (when the customer with DER is buying power from the grid) or payments (when that customer is injecting power into the grid) will vary, depending upon the tariff under which that customer is buying electricity service, the time/location of use (or supply), and the compensation scheme that exists in the system where that customer is located.

- The Value of D is also different from the full economic value that different customers place on using electricity, which – for a particular customer – may be (and typically is) higher than the distribution rate (and total electric rate) charged.

B. *The "Value of DER" for the electric system* is the cost (or cost savings) that the electric system experiences as a result of having a specific DER or portfolio of DERs in place and in operation, relative to the investments and expenditures that would otherwise be needed .

- Where DERs enable reliable *distribution* service at lower cost than without them, the DERs provide a value to the distribution system (i.e., "the Value of DER to D"). Where the DER helps to avoid wholesale-level delivery costs on the high-voltage transmission ("T") system, there is a positive "Value of DER to T." And where DER helps to enable the power-generation ("G") system to meet aggregate demand at lower cost, then there is a positive "Value of DER to G."

- Conceptually, the value to the electric system (and to each of its component parts (D, T and G)) depends upon the location where DERs are placed on the grid and the timing, duration and quality of supply provided by the DERs. Depending on its technology, attributes and location/operation, a DER may have net benefits or net costs to the electric system.

- If the system can fairly obtain the right quantity/timing/location of DERs it needs at a market-based competitive price (rather than at avoided cost), then there may be net benefits – i.e., value to the system and its customers.

- Thus the full economic value of DER to the grid may not be the same as the amount paid for DER.

C. ***The value of DER to the participating customer*** is the array of benefits that the customer receives from having the DER, net of any costs to that customer of installing, operating and maintaining it.

  - Such benefits may include satisfaction of that customer's objectives, such as: quality of service; lower environmental impacts; potential to better manage and stabilize energy prices; increased sense of energy autonomy; potential resiliency improvements; and so forth. These benefits may partially or fully offset any up-front and/or on-going costs the customer incurs for its DER.

D. ***The value of DER to the local community / society*** reflects the net impacts of DER deployment that go beyond the electric system and beyond the transactions between electricity suppliers and consumers (due to environmental and other externalities). These other impacts may include lower (or higher) overall air emissions and water use, higher or lower local employment, or transfer of dollars into or out of the local economy.

  - These externalities might be considered the "Value of DER to S" (society).

  - In some jurisdictions and under some economic constructs, other societal values enabled by the presence of DER – job creation and/or job loss, or lower environmental impacts of electricity production and delivery – may be incorporated into public policy decisions about whether DER provides cost savings, but these values may or may not be reflected in prices paid to DER suppliers.

Many if not most discussions of the Value of DER tend to pull these various components into a single framework, even though each element is distinct. One common outcome of this tendency is the practice of bundling all of these aspects of value into a single form of compensation rather than in a more unbundled or disaggregated form. But just as the line-item charges on a hotel bill allows the customer to track the different components (e.g., the cost of the room versus food purchases), a fully transparent system for valuing and reporting charges for (or compensation to) DERs would separately track its implications for D, and for T, and for G, and for S.

The Focus of this White Paper: Valuing DERs to D

In light of the deep literature that exists on tracking trends in DER deployment as well as on identifying the factors that contribute to the "Value of DER" to customers, the electric system and society, this particular paper focuses attention on a subset of the issues: How should utility regulators, distribution utilities and other stakeholders think about the value of DER *to the distribution system*? And what are the implications for DER procurement and compensation that result from those interactions between the DER and the local distribution system?

Other issues described immediately below – such as why DERs are expanding so quickly, how various parties tend to view DERs' role in a transition to a cleaner, more modern, more competitive and efficient electric system, and how public policies have been designed to stimulate and compensate participants in the DER market – provide the context for examining these DER/distribution-system interactions. The focus of this particular paper remains on "the Value of DER to D."

Although regulators, utilities, DER providers, and others are working hard in many places to refine benefit/cost concepts for evaluating when and where DER installations might provide value to the distribution system, other work is needed to further evolve planning and valuation tools, ratemaking approaches, and compensation arrangements for DER. Doing so increases the chances that DERs can be planned for and reliably secured at efficient prices, thereby creating value for all customers on the distribution system.

Shining a light on the Value of DER for D in this paper is not intended to suggest that these are the only – or even the largest source – of DERs' value proposition for the electric system and for society. Indeed, as described further below, the economic value of DER to D is a relatively small part of the total value DERs provide to the full electric system and to society. Rather, the purpose of the more-narrow focus of this paper is to attempt to focus attention on some of the particular issues associated with the Value of DER to D as utility regulators and other stakeholders grapple with how to understand this particular aspect of DERs' overall economic value.

Context for the need to properly value DER

DERs are proliferating rapidly in the U.S.

Although still comprising a small fraction of the U.S. total electrical capacity and generation in the U.S., DER installations have increased dramatically in recent years. Many technologies contribute to the growing DER capacity: rooftop solar PV systems; utility-scale solar facilities connected to the distribution grid; distributed wind; energy efficiency installations; remotely controlled smart thermostats; other forms of demand-response; micro-grids; high-efficiency CHP equipment; and many other types of "behind the meter" equipment and systems that allow customers to manage their energy use and generate their own supply.

These trends result from a combination of factors, including: policies adopted by states and implemented by utilities and third parties which promote adoption of distributed systems; technology cost reductions; and high customer interest.

The most influential policy drivers over recent DER deployment trends are state renewable portfolio standards ("RPS"), state net-energy-metering ("NEM") policies, and utility procurements of DER. (There have been other drivers in federal policy, as well, including incentives provided by the American Recovery and Reinvestment Act of 2008, and various federal investment tax credits for residential and commercial solar PV systems.[4])

As shown in Figure 2, approximately three quarters of the states and the District of Columbia have an RPS or goal designed to increase over time renewable power's share of electricity sold to retail electricity customers. Most state RPS policies have led to large-scale renewable energy projects, but some states' RPS count renewable supply generated from DERs. More targeted to distributed energy resources are the policies of the states shown in Figure 3, which indicates that 22 states and the District of Columbia have RPS policies providing a 'carve-out' or specific provision designed to encourage solar PV projects and other DERs.[5] Other states, like California and New York, have separate targets for rooftop solar installations that are supported through rebates, tax credits, and other approaches.[6]

Figure 2

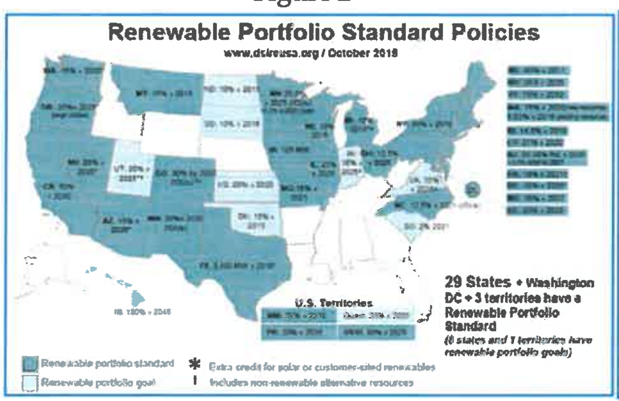
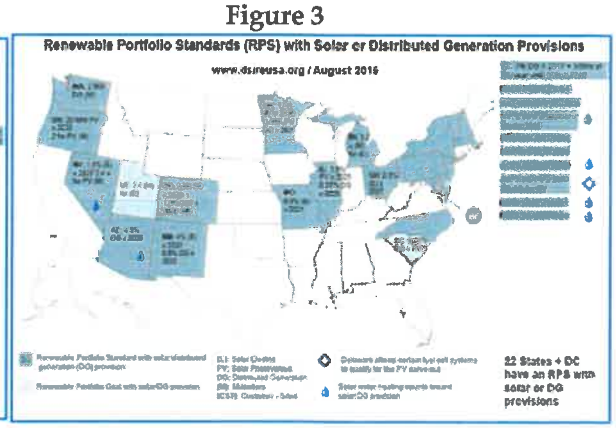


Figure 3



Source: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

NEM is broadly understood to have had one of the strongest roles in inducing additions of *distributed* renewable energy resources (especially rooftop solar PV systems). Eighty percent of the states have encouraged early rounds of solar installations by requiring the local electric utility to buy all of the surplus generation exported into the grid from a building with rooftop solar PV as indicated in Figure 4. States' NEM policies vary as to the level of compensation afforded to solar systems' output. As shown in Figure 5, most states compensate the customer with a solar system for surplus power at the full retail electricity rate (as indicated by those states with the darkest shading in Figure 5). Other states' policies start at the retail rate but reduce it gradually over time (states with the second-darkest shading on Figure 5). NEM, combined with rapidly declining costs of installed solar PV capacity and the ability of third parties (i.e., solar companies) to install systems on customers' roofs and then sell them the output under a long-term power purchase agreement, has stimulated significant growth in solar installations around the country (see Figure 6). Since 2010, when there were 151,000 solar PV installations providing 2,000 MW of capacity, "[t]oday there are more than 867,000 solar PV installations in the U.S., with new systems being installed at a rate of roughly one every two minutes."[7] The millionth installation is expected to occur in 2016.[8] (For context, total U.S. capacity from all generating resources was 1,072,000 MW as of the end of 2015.[9])

Figure 4

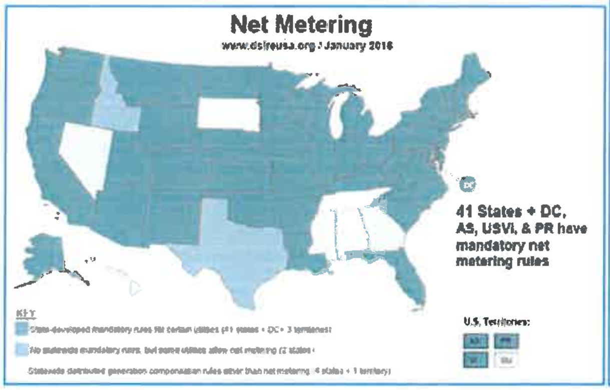
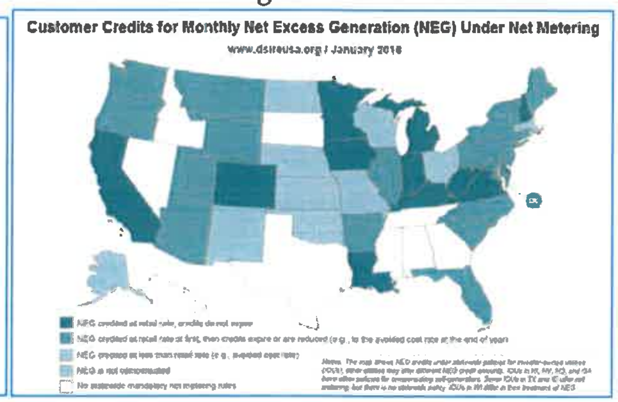


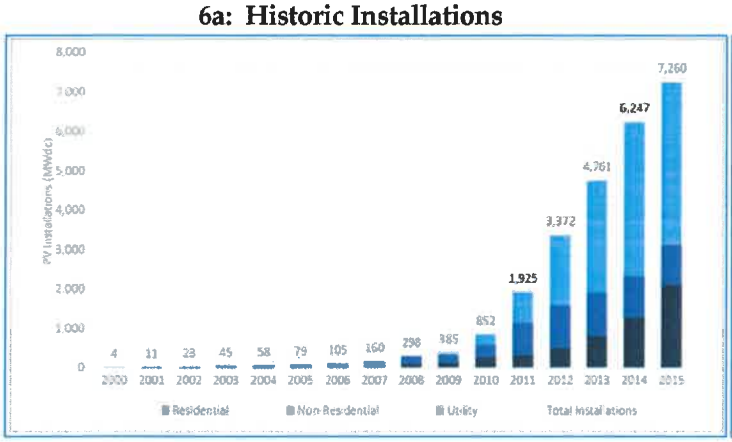
Figure 5



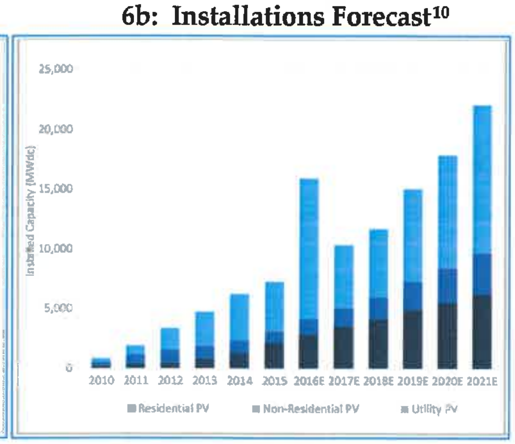
Source: Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/

Figure 6: U.S Solar PV Installations (in MWdc)

6a: Historic Installations



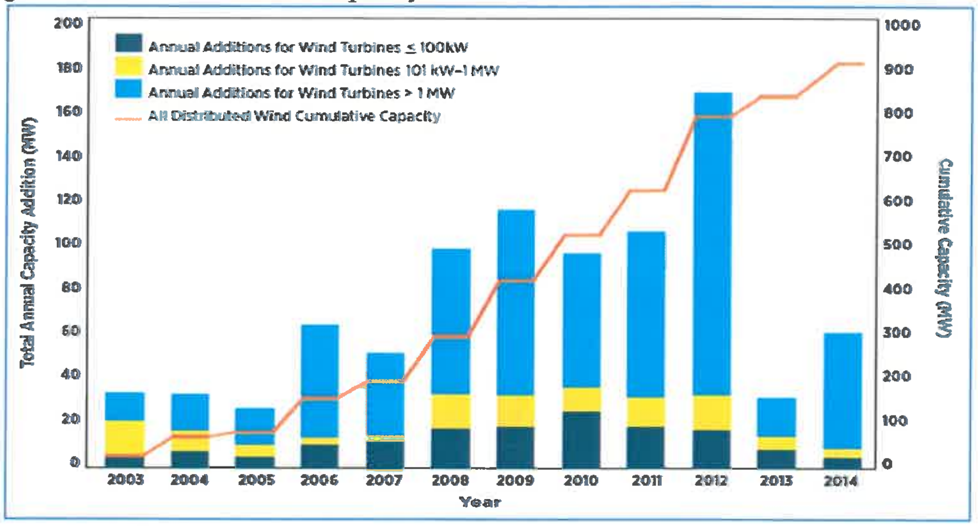
6b: Installations Forecast[10]



Source: GTM Research/SEIA, U.S. Solar Market Insight: Executive Summary, 2015 Year-in-Review, March, 2016, Figure 1.4 and 2.7

Turning to other DER technologies and options: By the end of 2014, over 900 MW of distributed wind capacity had been installed in the U.S.,[11] with the year-to-year additions and cumulative capacity installed over the past decade shown in Figure 7.

Figure 7: Distributed Wind Capacity Additions: Annual and Cumulative (2003-2014)



Source: Alice Orrell and Nikolas Foster, "2014 Distributed Wind Market Report," Pacific Northwest National Laboratory, August 2015

The most prevalent form of DER is energy efficiency, with consumers historically installing a myriad of measures to make their buildings and appliances more efficient. A retrospective review of the impact of energy-efficiency investments found that: "Without the numerous energy efficiency improvements made since 1973, the U.S. would require about 50% more energy to deliver our current GDP. The adoption of more efficient products and services is responsible for 60% to 75% of the increase in energy productivity since 1970."[12] States like Massachusetts (with its "all cost-effective energy efficiency" requirement) and California (with its "loading order" preference for energy efficiency ahead of other resource alternatives) have requirements that utilities favor energy efficiency over traditional utility investments where the former can provide cost-effective resources as part of utility service. Even though most states have required and/or encouraged utilities and third parties to offer cost-effective energy efficiency programs that overcome market barriers to customers' own adoption of energy efficiency measures, many analyses indicate that there remain deep and as-yet untapped energy efficiency savings available in most if not all parts of the U.S.[13]

Also, although CHP facilities in industrial locations and other buildings are not new, low natural gas prices combined with recent developments in efficient small-scale gas-turbines, reciprocating engines, and microturbine technologies have supported greater deployment of CHP in the past decade.[14] (See Figures 8 and 9.) Although some CHP facilities are at sites connected to high-voltage transmission lines, many are located on the property of commercial buildings and provide on-site generation at relatively constant loads across the course of a day, unlike many other DER technologies).

Figure 8:
U.S. Annual CHP Build by Size (# of Projects)

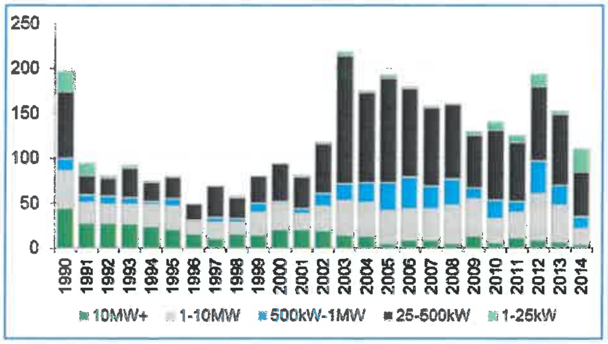
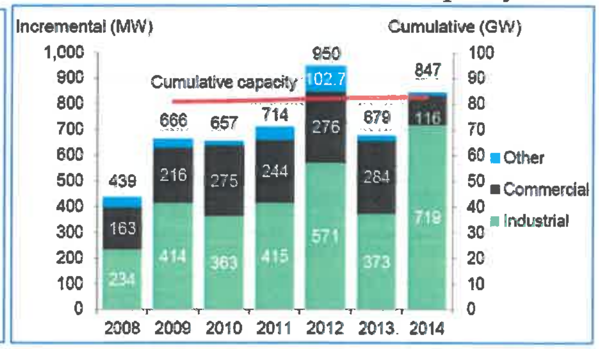


Figure 9:
U.S. CHP New Build (MW) and capacity (GW)



Source: Bloomberg New Energy Finance, 2016 Sustainable Energy in America Factbook

In recent years, centralized procurements of local capacity for reliability functions have encouraged targeted development of DERs. Two recent examples of utility procurements that resulted in contracted-for DERs are: SCE's solicitation of storage to help meet Local Capacity Requirements in the Los Angeles/Orange County regions in the wake of the closure of the San Onofre nuclear plant;[15] and Con Edison's Brooklyn Queens Demand Management Program ("BQDM") that is addressing local reliability in targeted neighborhoods of New York City.[16] Those two solicitations led to the selection of various DER technologies, including battery storage, demand response, microgrids, fuel cells, and energy efficiency, all of which have been increasing in volume across the country. (See Figure 10 for fuel cell deployments in the U.S. over the past decade). Also, procurements of demand response ("DR") by Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") have also led to increased DR capacity over the past decade as indicated in Figure 11, with the outlook for such deployments favored as a result of the recent Supreme Court decision upholding wholesale-market purchases of DR under regulations authorized by the Federal Energy Regulatory Commission ("FERC").[17]

Figure 10:
U.S. Stationary Fuel Cell
New Build (MW) and capacity (GW)

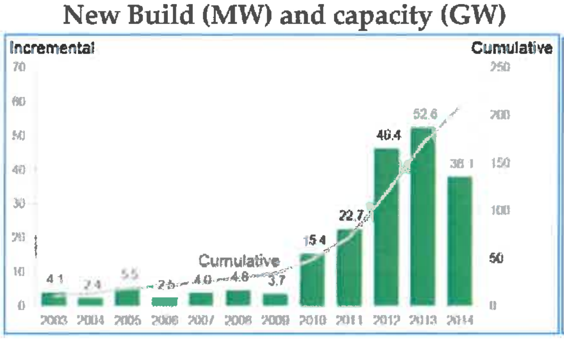
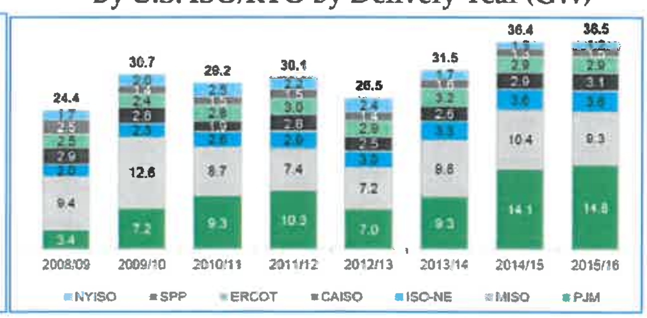


Figure 11:
Incentive-Based Demand Response (DR) Capacity
By U.S. ISO/RTO by Delivery Year (GW)



Source: Bloomberg New Energy Finance, 2016 Sustainable Energy in America Factbook

Views about the economic value of DERs are evolving

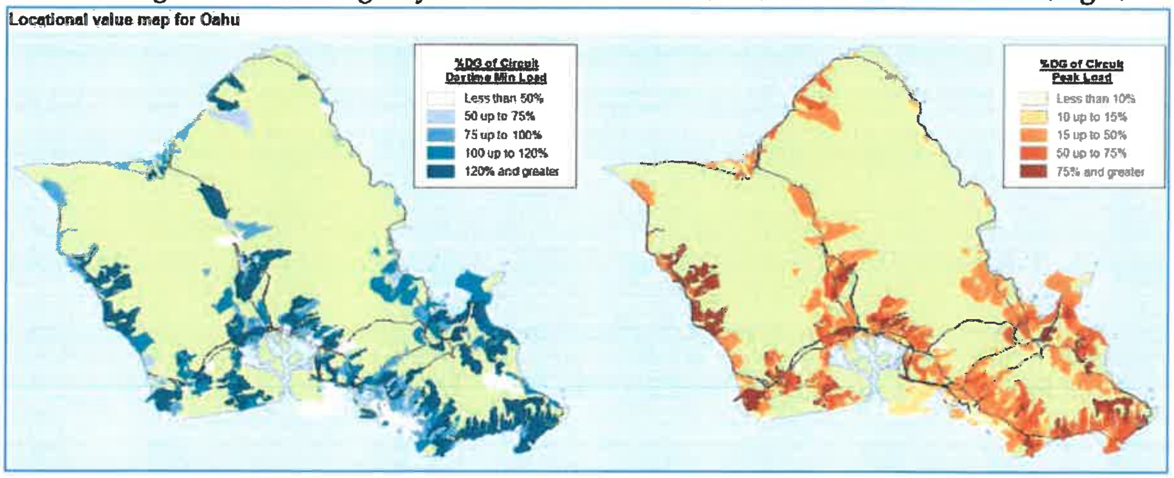
As DER installations and cumulative capacity continue to increase, many electric industry stakeholders are refining their understandings of the ways in which DER resources interact the electric system, how DERs are valued, and the prices paid to DER providers for their contribution to supporting the electric system.

Although the standard NEM approach has certainly been instrumental in spurring the development of DERs in the early stages of their deployment, net metering has recently come under scrutiny for being a too-imprecise, top-down instrument for compensating suppliers of solar DER. Different observers argue that it either over compensates or under compensates relative to the true value of DER to the electric system.[18] A recent study by Energy+Environmental Economics ("E3"), for example, which analyzed NEM in New York State's investor-owned utilities, found that with current NEM compensation, DERs had higher costs than benefits because NEM does not target DERs to places on the grid where they can avoid or defer distribution-related capital costs whereas with a more targeted placement of DERs can shift the benefit-cost ratio to positive. [19] Also, many stakeholders are concerned that NEM has led to significant cross-subsidies between those customers with NEM service and residential customers without it.[20] Approximately two dozen states have begun to examine ways to modify their NEM policies resources.[21]

For example, in Hawaii – where solar PV capacity has nearly doubled each year from 2007 through 2014 and PV panels now sit on 12 percent of electric customers' homes (compared to the U.S. average of 0.5 percent)[22] – state regulators decided in October 2015 to close the retail NEM rate for new customers and to replace it with a minimum bill approach, combined with one of two optional tariffs for compensating for solar generation.[23] (Figure 12 shows maps depicting the concentration of solar PV on distribution circuits in Oahu, with high percentages of PV systems often triggering the need for interconnection studies on the impacts of DERs on local distribution reliability. The darker colors show higher concentrations of PV relative to a circuit's minimum load (on the left) and a circuit's maximum load (on the right).) The changes introduced by Hawaii's utility regulators include a 'grid supply' option, which allows a customer with solar PV to sell output into the grid at the avoided cost of on-peak fossil generation. The other option ('self-supply') allows the participating customer to get a credit on their bill for on-site generation that is consumed on site.[24]

Further, in October 2015, New York regulators effectively removed all caps on new solar customers' ability to take service under the NEM tariff pending resolution of the state's proceeding to determine the value of DER (anticipated to occur during 2016).[25] In December 2015, Nevada regulators reset the NEM rate at the wholesale price of power, rather than the retail rate, and applied it not only prospectively to new customers but also retroactively to existing PV customers (although the latter decision is highly controversial and is currently under reconsideration as of this writing).[26] At the end of January 2016, California's utility regulators maintained NEM for new and existing customers, although new rooftop solar customers of Pacific Gas & Electric and SCE need to take service under time-of-use rates.[27]

Figure 12:
Density of Solar PV Systems on Electric Distribution Circuits
Percentage of DER During Daytime Minimum Loads (Left) and Maximum Loads (Right)



Source: EIA, "Hawaii's electric system is changing with rooftop solar growth and new utility ownership," *Today in Energy*, January 27, 2015.

And in Maine, a coalition including the state's consumer advocate, electric utilities, solar companies, and environmental groups has proposed a new market-based approach to procurement of and compensation for DERs.[28] The Maine legislature is now considering this proposal to replace the current NEM policy with a new "pay-for-production" approach in which the utilities or other designated parties would purchase and aggregate solar generation from private solar owners and utility-scale developers under long term contracts, and then bid the generation into New England's wholesale electricity markets.[29]

Clearly, a transition is underway to evolve the methodologies for valuing and compensating DERs for what they are providing to the electric system. But there is likely a large conceptual and methodological distance to be crossed between the traditional approaches (which values all DERs the same, regardless of technology and location on the distribution system), and the other methodological extreme (in which each and every DER has a different value, depending upon where it is located, what its electric generation profile looks like, and how it ends up interacting with other assets and loads on the distribution system).

The transition surely needs to move from the current extreme (using blunt valuation instruments) towards the other, without bogging down in so much technical sophistication as to be practically infeasible for ratemaking purposes.

Guidance in developing sustainable valuation frameworks for DERs for D

New valuation approaches should be grounded in the traditional utility-regulatory principles of efficiency and fairness

In anticipation of a continuing evolution towards more granularity and precision in the frameworks for estimating the Value of DER to D, many of the long-standing principles of public utility ratemaking offer useful guideposts for how to proceed.

Recall that timeless guidance on utility ratemaking set forth by James Bonbright, in his seminal book, *The Principles of Public Utility Rates*, published in 1961, emphasized the need for regulators to adopt utility rates designed fundamentally around principles of fairness and efficiency.[30] Application of these principles to distribution-related functions means designing rates so that they properly allocate costs to those customers making use of distribution service and fairly and efficiently compensate those providing functionalities that are useful to the electric distribution system. Rocky Mountain Institute's e-Lab has recently and helpfully re-interpreted Bonbright's ratemaking principles for today (with the more relevant ones reproduced in the text below):

e-Lab's Re-interpretation of Bonbright's Principles of Public Utility Rates	
Bonbright Principles	**21st Century Interpretation**
Rates should be practical: simple, understandable, acceptable to the public, feasible to apply… and free from controversy in their interpretation.	The customer experience should be practical, simple, and understandable. New technologies and service offerings that were not available previously can enable a simple customer experience even if underlying rate structures become significantly more sophisticated.
Rates should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.	Rates should keep the utility viable by encouraging economically efficient investment in both centralized and distributed energy resources.
Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.	Customer bills should be relatively stable even if the underlying rates include dynamic and sophisticated price signals. New technologies and service offerings can manage the risk of high customer bills by enabling loads to respond dynamically to price signals.
Rates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.	Rate design should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination.
Rates should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.	Price signals should be differentiated enough to encourage investment in assets that optimize economic efficiency, improve grid resilience and flexibility and reduce environmental impacts in a technology neutral manner.

Source: e-Lab, "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future," Rocky Mountain Institute, August 2014, page 38.

Thus, the utility should endeavor to pay the supplier of DERs for the fair value of the services provided by a particular DER installation (or a portfolio of them). As information and analytic techniques become more refined over time, it is likely that DERs using different technologies in the same location may provide different value(s) to the distribution system, and DERs using a common technology may provide different values to the distribution system as a function of where they are located on it. Such principles are important for three things: fairness among customers; efficiency in the expenditure of dollars dedicated to providing reliable utility service; and revenue stability and predictability to enable the utility to remain a healthy provider of grid services. These principles should apply to compensation arrangements for both 'mass-market' DERs (where installations results primarily from a customer's choice to install DERs to satisfy his/her own objectives) and DERs targeted specifically to help avoid a utility's traditional distribution-system investments.

Past PURPA experience – that market-based approaches lead to better customer results than avoided costs – is instructive for designing compensation for DERs

Another tenet to follow is avoiding mistakes that have been made in the past – in other words, taking advantage of learning the lessons from relevant past experiences in utility regulation at a time of industry transformation. In the case of the role of DERs for D and in structuring valuation approaches and procurement/compensation regimes, useful lessons come from the early years of implementation of the Public Utility Regulatory Policies Act of 1978.

Recall that PURPA is a federal law which required utilities to purchase power from eligible power producers at the utility's avoided costs – the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[31] FERC has delegated to the states the responsibility for implementing PURPA.

In the early years of PURPA implementation, most states initially required utilities to purchase power from PURPA facilities on the basis of energy-only tariffs that reflected a utility's short-term avoided production costs. As prospective PURPA facilities sought to provide not only energy but also capacity to the utility (and thus help to avoid the need for traditional utility investment in generating capacity), most states turned initially to formal regulatory proceedings as the means to establish administratively determined estimates of avoided cost.

Early on, these administrative proceedings produced standard-offer rates at which a utility would buy power from any PURPA facility willing to supply at that rate – sometimes without regard to the amount of generating capacity actually needed to avoid the utility's incremental capacity additions. In some cases, this led to an over-supply of output relative to the amount needed (and reflected in the administratively set avoided costs). In other cases, there was a misalignment of the attributes provided by a particular PURPA project (e.g., its technology or its location) and those the utility needed for reliability and/or energy objectives.[32]

Over time, many regulators and utilities recognized some inherent challenges of relying upon pricing set in administrative proceedings: that they can produce prices that are too low (in which case, they yield insufficient takers) or too high (where they can produce an oversubscription or increased consumer costs). Many regulators and utilities addressed these concerns through the use of competitive procurements as the means for setting avoided cost and for identifying the PURPA facilities that would get the right to supply power at that particular market-based price. This evolution eventually led to stronger pay-for-performance outcomes for competitive supplies of generation.

Paying attention to this history is important as the electric industry transitions away from the current methods to pay for DERs (typically set at the full retail rate under NEM). At the early stages of adoption and deployment of DERs, NEM has proven quite useful in stimulating the market for DERs (especially solar). This parallels the early outcomes of PURPA implementation. At present, many states are looking at administrative processes and avoided-cost methodologies to establish – in effect – the amounts to pay DERs for the resources they supply to the electric system (as described further below). But based on PURPA experience, states should quickly transition beyond such initial approaches and put in place market-based mechanisms (e.g., competitive procurements) to set prices and performance obligations for DERs selected to provide services to the electric system.

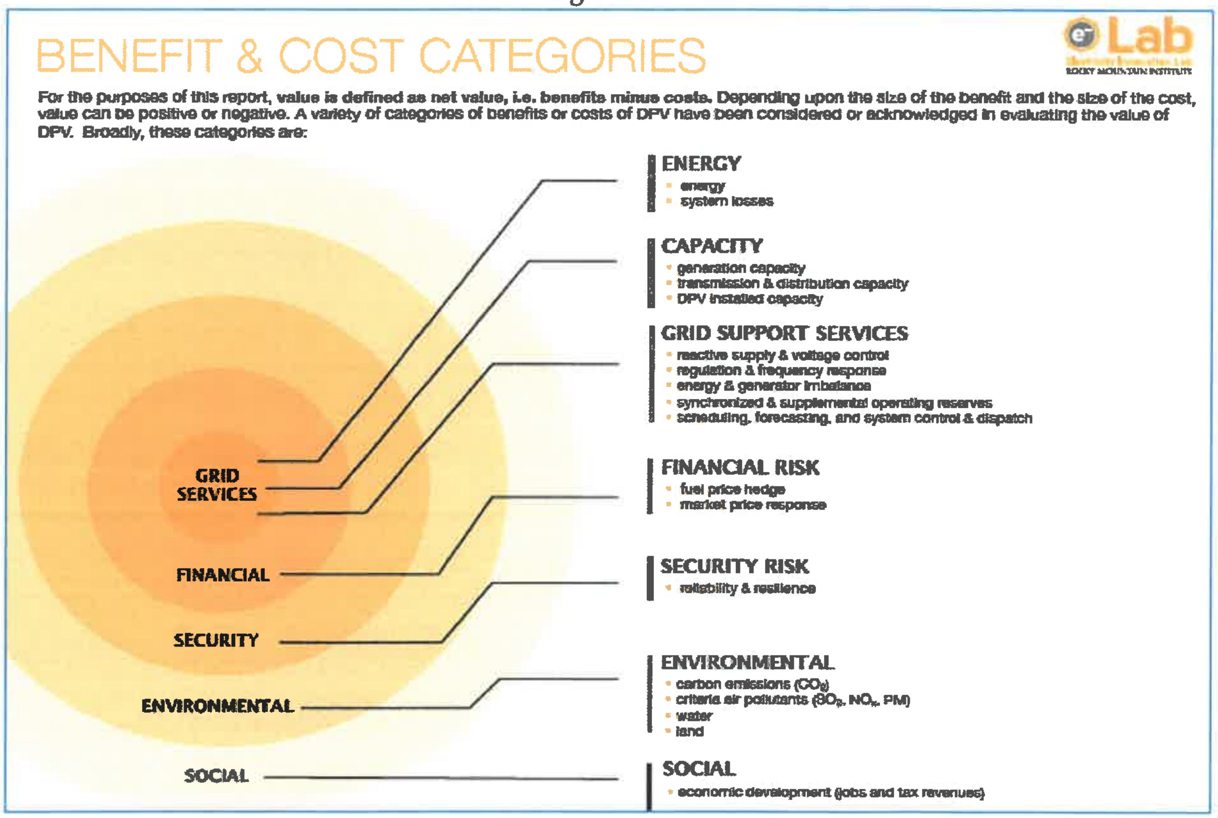
Benefit-cost studies of DERs provide indicative information about their potential to provide net benefits to the electric system, to participating customers and to society

Numerous recent studies have focused on identifying and calculating values for the full set of elements that comprise DERs' value in avoiding utility costs: their Value to D (distribution), their Value to T (transmission), and their Value to G (generation). Additionally, many of these studies also separately estimate the Value of DERs to S (society), which accounts for value not monetized within the electricity purchase/sale transaction. .

For example, e-Lab recently surveyed the literature on benefit-cost analyses of behind-the-meter solar PV resources, to examine their methodologies and their estimates of net benefits. The report identified the following categories of potential benefit and cost: *energy* (electrical energy and system losses); *capacity* (electrical generating capacity, distribution and transmission capacity, solar PV capacity); *grid support services* (including reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, synchronized and supplemental operating reserves; scheduling, forecasting, and system control and dispatch); *financial risk* (fuel price hedge; market price response); *security risk* (reliability and resilience); *environmental* (carbon emissions, criteria air pollutants, water, land); and *social* (economic development: jobs, tax revenues). (See Figure 13.) These categories incorporate the valuation building blocks that appear in a wide range of studies.[33]

Across the studies reviewed by e-Lab, the portion of total net benefits attributable to the Value of Solar for D is small (and typically lumped into a category that combines avoided transmission and distribution capacity). In four of the relatively recent studies, for example, avoided transmission and distribution capacity ("T&D cap") costs represent a very-small share of total net benefits of solar (as shown in Figures 14a through 14d for studies conducted on the value of solar in Texas (Austin), New Jersey/Pennsylvania, California, and Colorado.) Although the circumstances in each place vary (e.g., total size of net benefits, size of avoided energy costs, methodological approach), avoided distribution costs are small everywhere, relative to the total estimated value of solar PV in avoiding traditional utility costs. This same conclusion was reached in E3's recent NEM/PV study in New York State, which indicated that under business-as-usual NEM policy (which does not target solar PV toward places on the grid where it can provide value in avoiding traditional distribution-system investment), the avoided costs of DERs for D is a very small share of total avoided costs.[34]

Figure 13



Source: e-Lab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, September 2013 (hereafter "e-Lab 2013 Solar PV Study").

That said, according to e-Lab, one of the most significant gaps in valuation methodologies is in understanding the distribution component – that is, the benefits or costs that result from rooftop solar PV operations: their impacts on "the distribution system are inherently local, so accurately estimating value requires much more analytical granularity and therefore greater difficulty."[35]

Also, many of the benefit/cost components in these studies are externalities (e.g., carbon-emission-reduction benefits as estimated in the social cost of carbon, or macro-economic development/job impacts) that are not part of the current pricing structure of electricity. As such, they are typically not monetized within part of the electricity purchase/sale transaction. They are avoided societal costs. Depending upon the study, these may be small or larger components of full calculated avoided costs. But in the day-to-day provision of electric service, these are literally not part of the utility's avoided cost. Were the utility to compensate a DER supplier at this type of estimated full avoided cost (rather than its own avoided cost), then 'missing money' problems could arise, which should be addressed through a fair and transparent ratemaking technique.

Figures 14: Average Avoided-Cost Values Identified in Selected Studies

Figure 14a: Austin Energy (2012)[36]

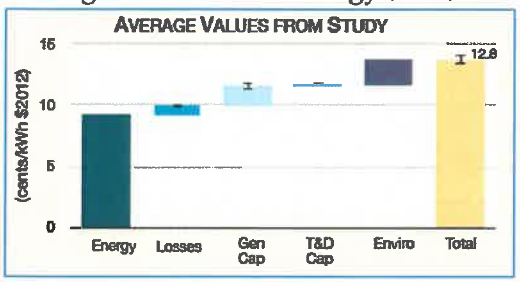


Figure 14b: New Jersey / Pennsylvania (2012)[37]

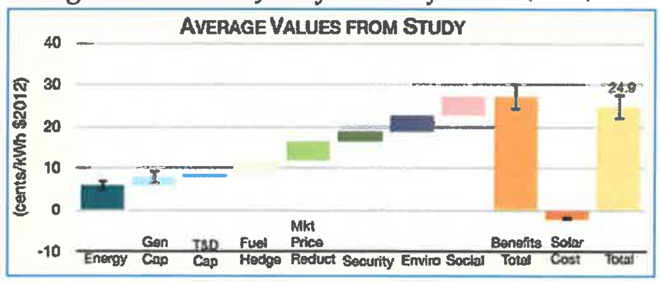


Figure 14c: California (2012)[38]

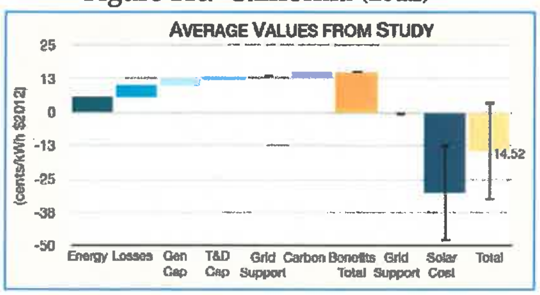
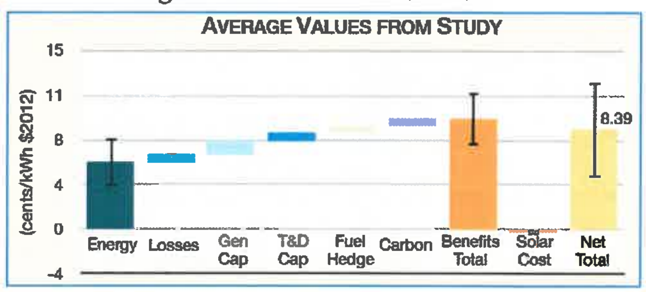


Figure 14d: Colorado (2013)[39]



Source: e-Lab 2013 Solar Study.

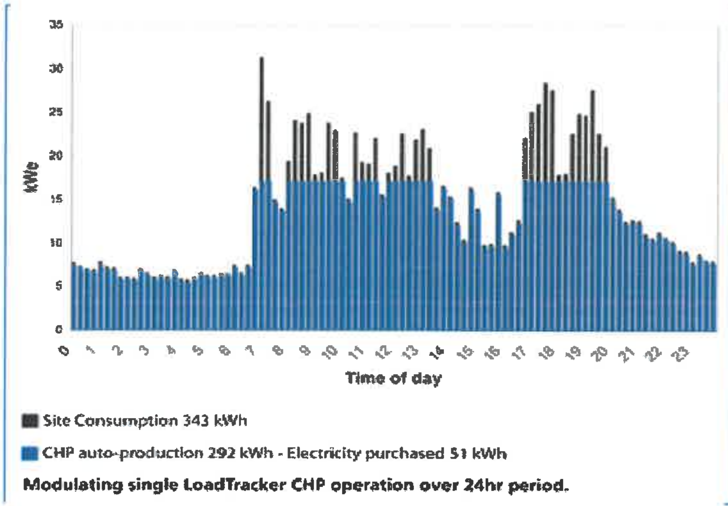
Benefit/cost methodologies are being considered in many regulatory jurisdictions to determine whether a utility's investment in DER is cost-beneficial relative to a more traditional investment (e.g., incremental distribution or transmission infrastructure). For example, as discussed further below, both California and New York are adopting benefit/cost frameworks, and then using them to evaluate whether a DER installation (or a portfolio of DERs) satisfies various (e.g., the Utility Cost Test, the Total Resource Cost test, the Participating Customer Test, the Non-Participants' Cost test (also sometimes known as the Ratepayer Impact Measure test), and the Societal test[40] – many of which have long been endorsed by utility commissions for the purpose of utility evaluations of the cost-effectiveness of energy-efficiency measures.

Valuation of DERs as alternatives to traditional distribution-system investment should account for the varied attributes that different DER technologies provide to the local grid

The DER valuation literature recognizes that different DER technologies have characteristics that enable them (or prevent them) from providing certain values to the electric system. From the point of view of the distribution system, the opportunity for greatest economic value rests with the ability of a particular DER technology and/or application (or a portfolio of DERs) to avoid specific distribution-system upgrades, and to do so with the same degree of necessary reliability and/or functionality afforded by traditional distribution investments.

Different DER technologies, of course, have different load-control and/or production profiles across the hours of any year, across years, and in different locations. For example, the figures below show the different performance of different types of DERs. Figure 15 depicts the output of a CHP unit (shown in blue) over the course of a day, thus capable of providing load-following resources over the hours, up to the maximum output given the CHP unit's size. To the extent that the customer's load was relatively flat (as opposed to the load shape depicted in Figure 15), the CHP unit could be optimized to serve most if not all of that customer's electricity requirements in a relatively reliable way, with the potential to avoid multi-hour overloads on the distribution system that might happen in the absence of the CHP project.

Figure 15:
CHP Output in Relation to On-Site Demand



Source: http://www.sav-systems.com/newsletter/issue-33-sav-loadtracker

By contrast, solar PV output will tend to vary across days and the hours of any day, in large part in relationship to cloud cover, existence of daylight, and season of the year. Figure 16 shows, for example, the output of the solar panels on my own rooftop in a recent week, with energy produced only during day-light hours and being highly variable depending upon cloud cover. The ability of my DER to help avoid distribution system overloads and defer traditional utility costs would depend upon its goodness-of-fit with the conditions on my utility's local distribution system in general and the specific segment of the circuit that serves my home.

Figure 16
Energy Produced from the Solar PV Panels on Tierney Roof
In 15-minute Intervals (kWh) During All Hours in a 7-day period (Sunday-Saturday) in July 2015

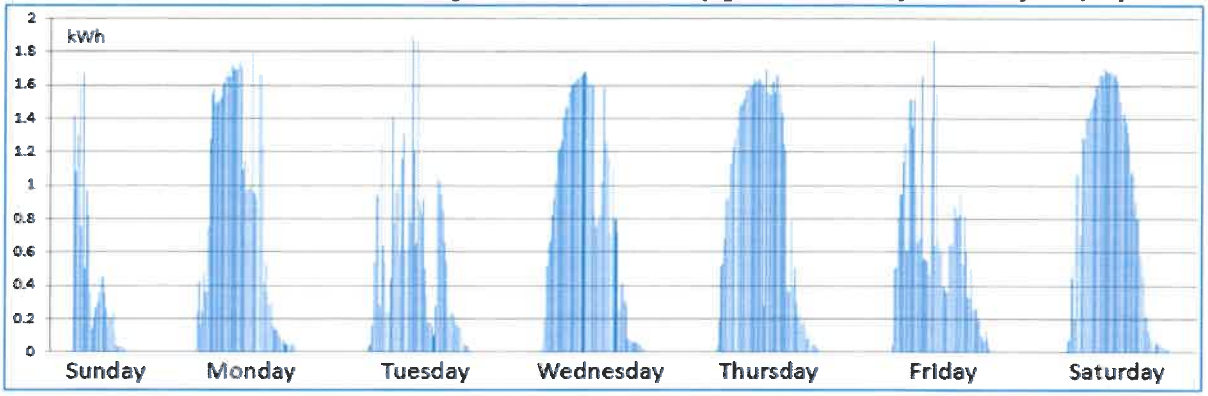
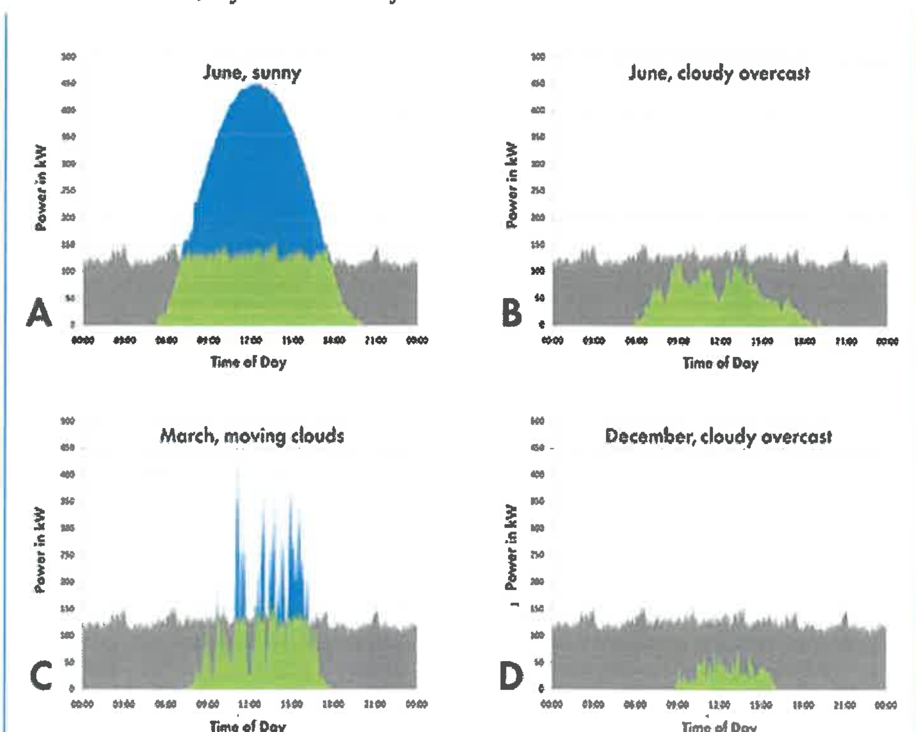


Figure 17 displays the output of a different PV system under various conditions, compared with the electrical load of the building (whose electricity use is relatively flat). Solar PV output consumed by the building itself is shown in green, with output fed into the distribution system shown in blue. The patterns of solar output vary considerably across these various conditions (and in the absence of storage).

Figure 17: Solar PV Output on a Building During Several Seasons, By Time of Day and In Varied Weather Conditions

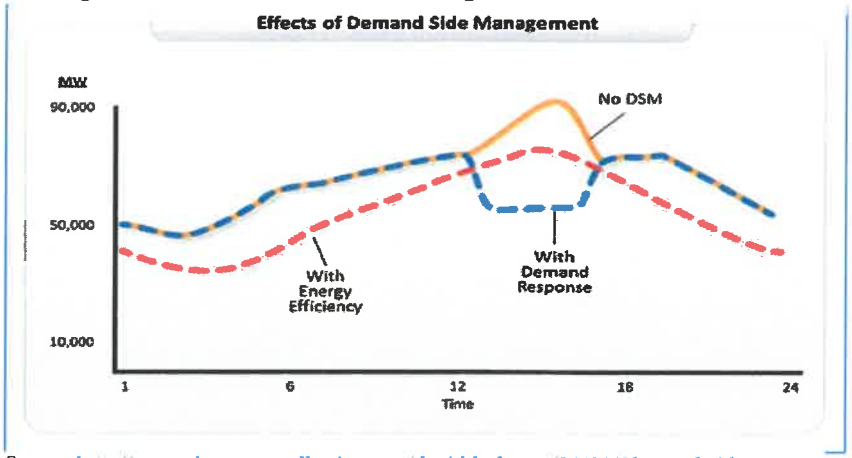


Source: http://www.sma.de/en/partners/knowledgebase/commercial-self-consumption-of-solar-power.html

To underscore the point: Demand response is a DER that a distribution company (and/or the wholesale grid operator) might have in place so as to be called upon during critical conditions on the system to reduce loads for one or another purpose (e.g., wholesale capacity obligations; distribution-system reliability needs on a particular circuit).

Figure 18 illustrates the potential capability of demand-response resources to be dispatched to lower customers' demand at critical times, including for the purpose of assuring local reliability requirements. To date, however, DR resources have tended to be relied upon for wholesale and/or bulk-power system functions (e.g., electric-system resource adequacy) and not for distribution-system purposes. Even so, such resources have the potential to avoid and/or defer distribution upgrades where there is a good locational fit between the place(s) where distributed DR can be deployed and the spots on the distribution circuits that would otherwise need upgrades to avoid reliability problems.

Figure 18: Effects of Demand Response on Customers' Loads



Source: http://www.theenergycollective.com/david-k-thorpe/244046/demand-side-response-revolution-british-energy-policy

For the utility to confidently rely on DERs to actually defer/avoid traditional distribution investments will require assurances that the DERs will provide a level and quality of reliability comparable to what would have been provided through traditional distribution upgrades. It would not be helpful to the other customers who are counting on local electric reliability if DERs were counted on (and paid) to postpone utility distribution investments, but did not, in the end, perform at an equivalent level of service to the local grid. Any anticipated fatigue factor in DR performance, for example, will need to be understood and factored into plans that rely on DR as part of distribution-system planning.

Distribution utility planning for and procurements of DERs can help ensure that DER have attributes targeted to the utility's needs

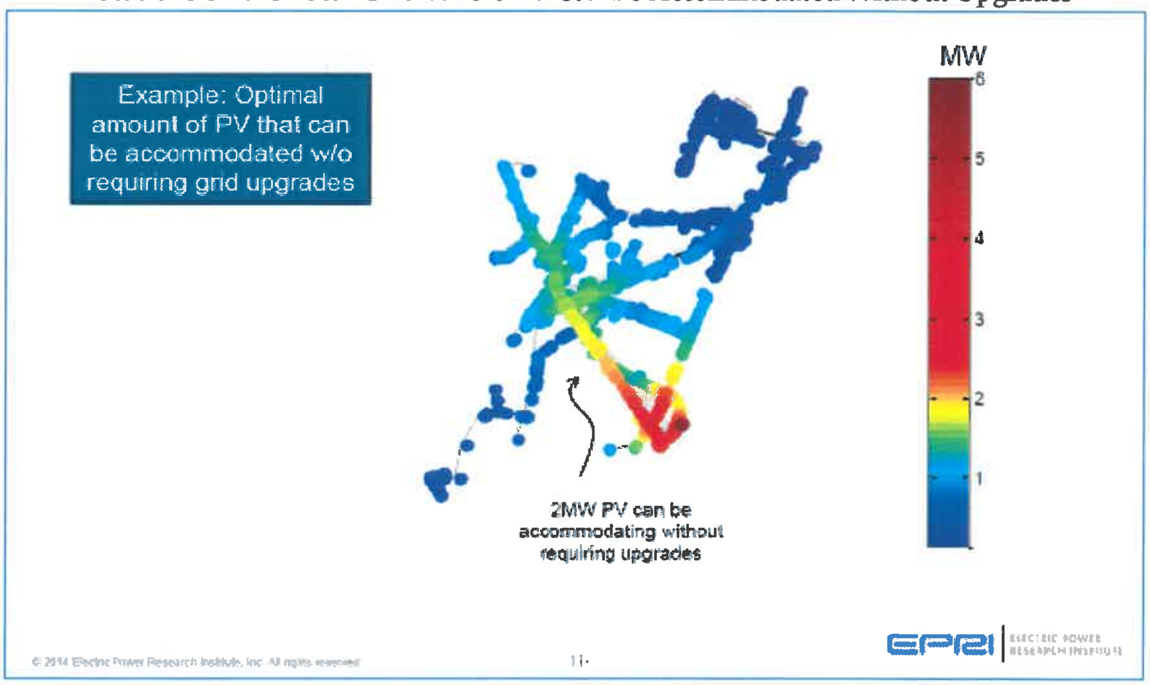
With a few notable exceptions (e.g., Con Edison's BQDM project and SCE's procurement of local DERs in the Los Angeles Basin), most DERs to date have been put in place by customers (rather than the utility) or third parties who seek the benefits of the DER for their own objectives (rather than the utility's). Some parties refer to these as "customer-driven," or "autonomous," DERs.[41] These customer-driven DERs have impacts on local distribution systems, of course: they sometimes free up room on local feeders, and in other circumstances, they can introduce operational challenges on the local distribution system.

As utilities themselves rely more upon DERs as potentially cost-effective alternatives to traditional distribution-system investments, they will need to proactively integrate DERs into their distribution-system planning and to procure those resources with attributes and locations of genuine value to the local grid. This means that the currently most prevalent forms of DER compensation – that is, utility tariffs and time-of-use rates that allow customers to opt-in to provision of DERs, often without regard to location on the distribution grid[42] – will need to evolve. To rely on DERs as part of the planned-and-operated local grid, the utility will need to have programs and/or procurements intended to lead to DERs with particular attributes and located in particular amounts and locations on the grid.

For example, utilities could target DER offers to specific customers located in certain parts of the system. Examples include:

- Utility offers to own and install solar PV systems on certain customers' premises.
- Utility incentives to encourage customers' adoption of energy efficiency measures.
- Utility information platforms and programs to indicate where DERs may be installed on the grid without additional integration costs. (This is sometimes called information about a utility's "hosting capacity" – that is, the grid's capability to host (integrate) additional installations of DER without any need to upgrade equipment to absorb the new local resource).[43] (See Figure 19, showing a map of locations on the distribution system with available hosting capacity and those with relatively high current penetrations of DERs.)

Figure 19: Illustrative Solar PV Hosting Capacity Map
Locations on the Local Grid Where PV Can Be Accommodated Without Upgrades



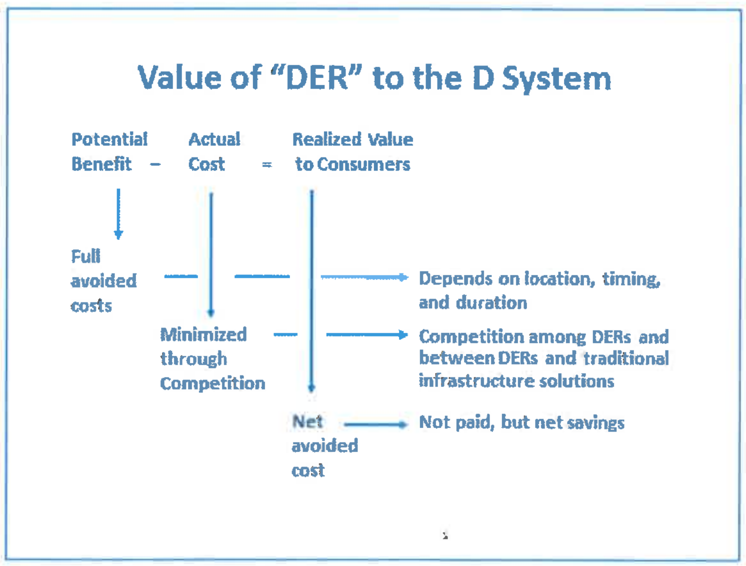
Source: EPRI map, presented in Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart: Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015, page 42.

- Utility programs to procure DERs with particular attributes and in targeted locations in order to provide distribution functions to the local grid. Examples include:
  - Local distribution utility 'requests for information' and/or 'requests for proposals' for DERs to provide temporary and/or permanent local load relief. (See Con Edison's 2014 "Request for Information: Innovative Solutions to Provide Demand-Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements."(This is Con Edison's BQDM project solicitation.) [44])
  - Competitive solicitations for offers of DERs to provide grid-support resources to the local utility at market-based prices, with long-term contracts to support installations and future performance of such DERs. (This is what is envisioned in the Maine settlement proposal for a market-based mechanism to replace NEM.[45])

Market-based procurement and compensation mechanisms for DERs designed to displace utility investment can create real value for the distribution system and its customers

Building off of prior PURPA experience, utility methods for procuring and paying for DERs should take advantage of the potential for innovation and efficiency that can result from competitive processes. Such evolution would recognize that benefit/cost analyses of DERs (relative to utility's traditional avoid costs) are the first, but not the last step, in determining which DERs provide greatest value at lowest cost. Obtaining DERs using market-based means may result in DERs coming forward in targeted locations at competitive prices that are lower than avoided cost, and thus producing net benefits to the system as a result of incorporating DERs into distribution system plans and reliability solutions. This would be the step that would enable DERs to actually provide value to the electric system and all of its customers (by providing reliability at a lower cost than would otherwise occur, as illustrated in the "net avoided cost" shown in Figure 20[46]). Periodic procurements would also be able to take into account the changes that inevitably occur on the distribution system over time, with some changes pushing out the date of need and others leading to earlier reliability challenges than previously anticipated.

Figure 20



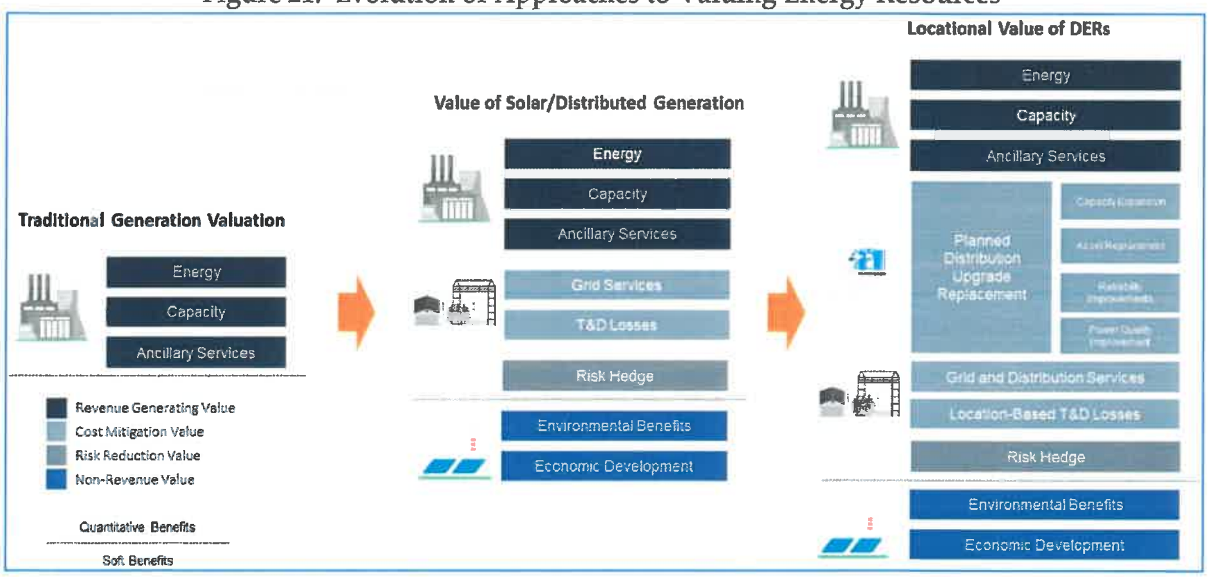
Targeted procurements and market-based compensation mechanisms send very-different economic and market signals to customers to install DERs for the benefit of the distribution system, as compared to the direct benefits that accrue to those customers themselves or to the larger electricity system. These approaches would be quite-different than current NEM compensation arrangements (which are currently subject to active debates about whether NEM tends to over- or under-compensate DER suppliers for their value to the system).

Using market-based mechanisms to procure and price DERs for their Value to D, however, does not completely answer all questions related to compensating DER suppliers for their overall value. Is this enough to provide efficient price signals, given that when DERs enable participating customers to avoid a purchase of electricity, those DERs lower the customers' payments for the generation-related portion of their electricity bill. The current proposal in Maine is addressing this question by establishing a role for the utility in aggregating the energy reduction and/or supply from DER providers and bidding them directly into the wholesale power market.

Another thorny question relates to whether and, if so, how DER suppliers should be compensated monetarily for the societal costs they avoid through their supply (e.g., avoided carbon emission costs not already internalized in wholesale power prices). By definition, any such costs are externalities and not part of payments between consumers and suppliers of electricity. Therefore, paying DER suppliers for such costs means that these are not costs that the utility itself would have avoided and would be outside of its normal cost of service. To avoid a missing money problem, therefore, long-standing ratemaking principles hold that if regulators seek to ensure that DER suppliers are compensated for this value then it also follows that regulators should also ensure such costs are fully recovered in a fair and transparent way from all customers of the electric system. This would clarify to customers that they are contributing to important social objectives (e.g., carbon reduction), above and beyond the levels currently embedded in electric-system operations.

From the point of view of the Value of DER to D (as opposed to its value to T, G and S), the industry is only beginning to fashion procurement and compensation approaches that connect payment amounts to DER providers to the value that specific DER technologies/applications provide in the context of quite-specific locations on the distribution system. As noted by e-Lab, the "[m]ethods for identifying, assessing and quantifying the benefits and costs of DPV [distributed PV] and other DERs are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees, and pricing structures for DPV and other DERs....Thus far, studies have made simplifying assumptions that implicitly assume historically low penetrations of DPV. As the penetration of DPV on the electric system increases, more sophisticated, granular analytical approaches will be needed and the total value is likely to change."[47],[48] As shown in Figure 21, GTM Research has depicted the gradual shift in resource mix and valuation approaches, from the electric industry's historical reliance on traditional central-station generation, to the current era in which utilities and regulators have been fashioning mechanisms to value DER in parallel with supply-side resources. Figure 20 also points to a future time when the value of DER will reflect the specific impacts (positive and negative) associated with DER technologies with different supply profiles and with applications in particular spots on the grid. (Note that GTM Research's graphic extends beyond the Value of DER for D to also include the Value of DER for T, G, and S. With respect to the elements directly affecting the Value of DER for D, Figure 20 lists the following components: Planned Distribution Upgrade Replacement, including Capacity Expansion, Asset Replacement, Reliability Improvements, Power Quality Improvements, as well as Grid and Distribution Services and Location-Based T&D Losses.)

Figure 21: Evolution of Approaches to Valuing Energy Resources



Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

EPRI has taken a number of steps to advance the state of knowledge on such issues. In its Integrated Grid framework, EPRI points out that a "common practice in value-of-solar studies is to first establish benefit categories and then to search for contributions in the form of avoided costs—for example, avoided generation, T&D, and distribution capital costs calculated in long-term planning studies. However, if the studies did not model the characteristics of DER contributions to meeting electricity demand and did not identify the electric system costs incurred to accommodate those resources, the attributed avoided costs fall short of portraying the complete net benefit picture. That representation becomes even less credible if the location (on the grid) and type of DER are not accounted for explicitly."[49]

Implications: Integrating DERs into distribution system planning and market-based solution sets

Local distribution planning processes should explicitly consider DERs and their potential value relative to traditional distribution solutions

Ultimately, the value of a particular set of DERs to a particular distribution system depends upon two things: the goodness-of-fit between those DERs' attributes and the types/location/timing of reliability problems the utility needs to solve; and the existence of net economic benefits that result from pursuing the DERs as compared to the traditional utility solution. Distribution-system problems (e.g., thermal overloads on the system, due to load growth; voltage problems; old wooden poles that need replacement; service restoration after storms knock down poles and wires) vary in ways that are important for determining the relevance of particular DERs for addressing that problem as well as the costs of a traditional solution compared to a solution based on a portfolio of DERs. Some of these problems (e.g., deferring upgrades needed to mitigate anticipated reliability violations attributable to load growth) can be addressed by DERs with certain attributes at certain locations; but other problems (e.g., pole replacement) may not be avoidable by DERs.

In most respects, the traditional approaches to resolve reliability issues on the distribution system involve decisions in planning/investment cycles that span many years. The utility conducts distribution-system planning on cycles that anticipate the character, timing and location of changes in customer demand and other factors on its system in future years, timed with lead times of various solution sets. This suggests that in order to effectively defer or avoid traditional utility capital investments in distribution infrastructure projects, DER solutions must be identified, installed and available to operate consistent with time frames associated with the utility's normal planning and construction cycles for such projects.

Historically, distribution-system planners have endeavored to anticipate and then analyze situations where changes on any particular part of the system might lead to reliability violations in the future without a planned fix. Among other things, this planning process looks at drivers affecting demand conditions on local feeders, transformers, and other parts of the distribution system, including such factors as population changes, known development and construction projects, building abandonments and tear downs, addition of large numbers of electric vehicles, customer-driven DER installations, and changing patterns of use that might affect the peak hour of use on a particular circuit or part of the network. This type of planning focuses on changes affecting specific parts (feeders, circuits, substations) on the system to identify places where capacity and/or voltage conditions will need to be addressed in the future.

The planner anticipates that a particular circuit or part of the network could become overlooked or otherwise violate reliability standards in the future (e.g., one to five to ten years into the future[50]), and then the utility looks for actions and investments that minimize the overall cost of fixing the reliability problem while optimizing the use of existing capacity on the system. A traditional distribution-system fix might be to add greater capacity (e.g., an upgrade in the circuit) in a particular part of the system in order to avoid the anticipated reliability problem. Traditional distribution-system planning has focused on reliably and safely accommodating one-way flows of electricity from the system to serve electricity consumers' demand at all times, which is, of course, changing with the integration of DERs that produce power for export from a customer's premises on the distribution system.

Most of the traditional fixes are capital investments,[51] many of which are expensive and have long lead times that are taken into account in the utility's planning horizon. These traditional solutions are designed to reinforce the physical capability of the infrastructure to meet customers' electrical requirements including standards for reliable service delivery and safety at all times of day. These characteristics suggest that the market for reliability solutions for D – that is, the market for DERs to serve as alternatives for traditional distribution solutions – has features that resemble a long-term resource adequacy issue (i.e., in the context of utilities that rely on integrated resource planning with competitive procurements to discover the least-cost solution), or a long-term capacity market (in those regions which have adopted them in wholesale markets). This suggests that at least in the early stages of the evolution, the focus of market design and implementation ought to be on ensuring that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide the same functionality as would have been provided by the utility's traditional capital-investment solutions. And it further follows that if DERs (rather than those traditional investments) are to be incorporated into distribution-system plans and operations, then those DERs need to show up and perform when needed in order to mitigate the anticipated reliability concerns.

Integrating DERs to add value to distribution-system plans depends upon paying competitive prices for comparable performance

Taking these considerations in account, then, it seems logical that utilities should proceed to fashion and conduct competitive solicitations of DERs that can offer to provide certain reliability-related attributes in specific places on local grids. With offers in hand, the utility can analyze how combinations of offers might create a portfolio of DERs that together promise to satisfy the utility's needs at lowest cost. The utility can then enter into contracts to assure that that group of DERs actually materializes and solves the local reliability problem cost-effectively and to do so with equivalent reliability as the utility's traditional solution would have provided.

As noted previously (and shown in Figure 20), such a competitive procurement process for DERs can create efficiency and overall net savings (i.e., realized value) to consumers. Such a process moves beyond the starting point of determining administratively how DERs could potentially create value by avoiding traditional utility costs (which is the current focus of so much effort in regulatory proceedings in many states). The competitive procurement process would reveal which DERs can actually avoid the utility's investment cost-effectively and what is the efficient price for acquiring such capability. Any difference between full avoided cost and market-based price produces the net savings – again, the realized value – to all consumers from incorporating and integrating DERs into its distribution-service solution set.

Distribution utilities' competitive solicitations for DER offers should focus on providing prospective DER suppliers with information about the attributes that the utility needs to mitigate anticipated local reliability problems, in order to encourage innovative and creative solutions.[52] Attributes of interest should be provided in as granular a fashion as possible, with regard to time of day, location in a particular part of a circuit or network, number of hours of preferred performance, operational firmness, and so forth. (Such disclosures might need to be subject to non-disclosure agreements if necessary for system security reasons.) These attributes would characterize the services the distribution utility needs to obtain from DERs in order for them to concretely defer traditional distribution investments.

This latter point is worth repeating: in a world in which distribution utilities pay for and count on DERs as the means to address anticipated reliability needs and then postpone/forgo traditional investments, it will be imperative that the DERs actually perform the agreed-upon services. As explained in the recent Lawrence Berkeley National Laboratory paper,[53] the

> following steps provide a logical sequence of considerations for regulation of electricity distribution systems in a future with high DER penetration.
>
> - **Step One: Ensure physical capability and reliable operation of the distribution system.** The first, and primary, considerations derive from the fundamental question of how to plan and operate an electric system with significant amounts of customer and merchant DERs in order to ensure safety, reliability, resilience and affordability. Design choices must respect the physical laws governing the electric distribution system while achieving public policy objectives. Planning and operational concerns are primary not because they are more important, but because they provide a foundation for subsequent decisions about market design and organizational structure, which must be made to align with the operational needs of the high-DER distribution system.
> - **Step Two: Develop market and regulatory structures to fully realize DER value** The second set of considerations related to fully realizing the value of DERs for distribution (and bulk power) systems requires that they can effectively and substantially reduce T&D operational expenses and offset investment in T&D infrastructure and utility-scale generation. This in turn requires a market and regulatory framework to ensure DER availability and performance when and where needed.... Where DERs are proposed to avoid distribution or transmission investments, the much longer lead time for building the foregone traditional grid upgrade requires enforceable assignment of accountability for the DERs to be operational, and with the needed performance characteristics, by the time the grid upgrade would have needed to be in service. This means that market structures and associated regulatory frameworks need to consider the whole life-cycle, from identifying the needs that DERs could fulfill, to determining the best portfolio of

DERs to meet each specific need, to procuring, implementing, dispatching and operating the DERs to meet real-time grid operating requirements.

There are significant economic risks associated with actually posting the utility's full avoided cost as the target price in competitive solicitations for DERs as alternatives to traditional utility investment. Based on a deep body of PURPA experience, academic research[54] and best-practices in utility solicitations,[55] advance publication of full avoided costs tends to lead to results in which bidders peg their offer prices to the utility's avoided cost, rather than to their own financial requirements needed to supply the DERs to the utility.[56] As the market for DERs transitions to more competitive pricing in the future, the goal should be to design these market-based mechanisms so as to produce efficient prices – and thus to create net savings to consumers. Consistent with standard-practice rules for competitive solicitations on the generation side, there should be safeguards to assure a fair and efficient outcome.

Utility contracts with the successful DER offerers should include commitments to pay for delivered capacity (e.g., milestones for installation of the DERs) and payments tied to actual performance over time (e.g., the DER remains durably in place over time) and when called upon (e.g., solar PV output under certain peak conditions; demand-response delivering load reductions when dispatched). Penalties for failure to perform could provide incentives for more certain and more durable performance from DERs.

The combination of such forward procurements of DER capacity and contractual provisions tied to performance can facilitate DER suppliers' entry into the market for distribution-system solutions. Similarly, the approach should help build experience and assurances over time as to the reliability of DER portfolios for satisfying distribution-system requirements.

Moreover, given that most of the value that DERs may provide to the electric system and society comes from sources other than the distribution system – e.g., avoided energy and capacity in the wholesale power system; avoided transmission line losses; avoided carbon emissions from energy production and delivery – then such competitive procurements of DERs for D can help provide price discovery for what amounts of compensation are needed and efficient to come from the distribution utility in order to make the DER viable economically and financially.

Note that this discussion assumes that for the near term, at least, it is more important to focus on evolving from current NEM tariff designs toward a forward market for distribution-system DER capacity for larger facilities and for DERs explicitly solicited for solving distribution-related reliability issues (especially in the absence of storage). This also assumes it is important to gain experience in implementing that procurement/compensation model before sharpening the tools for operational markets for DERs for D. The latter may hold more promise once there is a deep penetration of DERs, allowing for many potential sellers with different technical, institutional and financial capabilities to participate actively in distribution-system operational markets.[57]

That said, there are active opportunities for distribution-system DERs to participate in existing and still-evolving wholesale electricity markets. There are numerous opportunities for DER aggregators (either the distribution utility and/or third parties) to offer DER energy and ancillary services into wholesale markets (such as those in New York, New England, and the PJM footprint).[58]

In the future, as the markets for DER for T evolve, it may be worthwhile to look at the other shorter-term/operational sources of value of DER to D (such as voltage support), and then refine shorter-term/operational markets to compensate for such non-capacity-related services provided by DER to D. After the main source of value (distribution capacity) provides the lion's share of value, then these other value streams can be layered on top of that foundation.

This prioritization of "DER-for-D" market elements – starting with forward DER capacity procurements as the main event, and then moving toward more secondary and likely smaller transactional markets over time – fits not only with the need to make progress in market and regulatory developments (without perfection being enemy of the good), but also with economic principles about the conditions that enable robust, successful markets to exist. Note that these conditions (shown at right) – e.g., many buyers and many sellers, low barriers to entry, non-discriminatory access of market participants to essential facilities necessary to participate in markets, means to mitigate the ability of market participants to exercise market power[59] – are not yet in place (much less fully designed) for the market for DERs for D. Rather, issues relating to establishing such conditions in the future are under active discussion in leading states (e.g., California, New York, Hawaii). When the standard conditions for successful markets are absent, they may inhibit efficient prices. As such, it seems premature to focus on more than getting the most important DER product markets ready for prime time in the near term.

Standard Conditions for Successful Competitive Markets

- Many Buyers and Sellers
- Low Barriers to Entry (including price levels that support (over time) entry of new investment)
- Non-Discriminatory Access of Market Participants to Essential Facilities and Other Services Necessary to Participate in Markets
- Means to Mitigate the Ability of Market Participants to Exercise Market Power
- Informed Consumers
- Transparency of Prices and Options
- Relatively Stable and Transparent Market Rules

One final point here: In light of the active role and effort that electric distribution companies will be expected to take in eliciting and putting together portfolios of DERs to provide equivalent and more cost-effective reliability functions as compared to traditional utility distribution solutions, it would seem prudent that regulators ensure that there are adequate financial incentives to align the utility's efforts with customers' interest in efficient outcomes. Such financial incentives could arise in many forms, including compensating utilities for providing value for customers through this portfolio-aggregation and/or management function (until the market is capable of providing such a service in the future).[60]

Insights from practical application of distribution-system valuation analyses: SCE and Con Edison

Case Studies: Con Edison and SCE

For now, the markets for DER for D are still in their very-early stages. Most of the attention to date has been on developing the benefit/cost tools for evaluating cost-effectiveness, rather than on designing and testing out market mechanisms to procure DERs at competitive prices (rather than administratively established prices). So far, these methodologies tend to resemble a body of accounting tools with different categories of value where the analyst can fill in the blanks with real numbers applicable to a specific distribution utility's system.

For the Value of DER for D, the seemingly straightforward task of completing the spreadsheet is likely to be fairly daunting. Determining the value of a particular DER application (or portfolio of DER technologies and applications) in specific utility contexts will likely end up being much-more complex and difficult to execute than the simplified accounting framework might suggest.

That challenge, however, should not prevent the industry from attempting to develop more evidence-based approaches to DER valuation consistent with the long-standing ratemaking principles of efficiency and fairness. At the same time, the industry should continue to attempt to produce methodologies that support the entry of cost-effective DER resources into electric distribution system planning and operations.

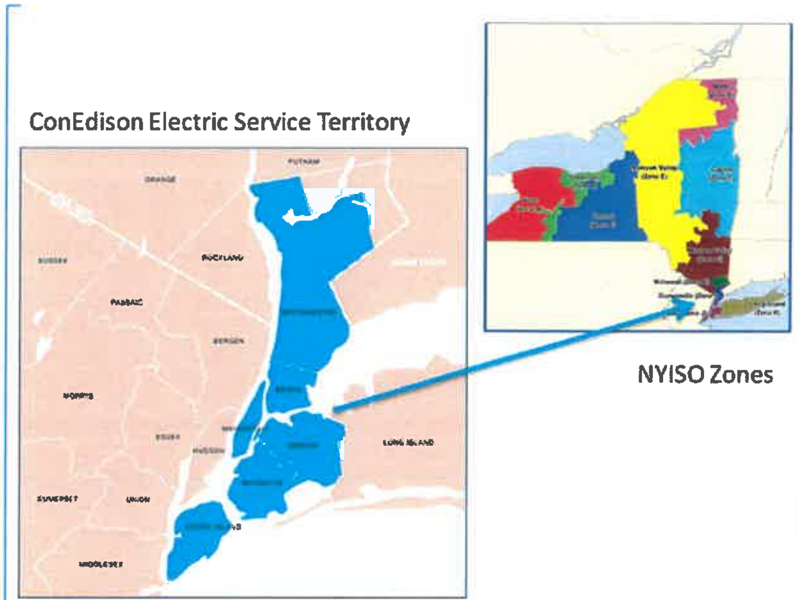
Two utilities – Con Edison in New York City and SCE in Southern California – are attempting to advance the development and application of such methodologies to understand and integrate the Value of DER to D into their distribution system planning and problem solving. Focusing here on their efforts as case studies is intended to provide insights into some of the analytic challenges as well as to inform the industry's evolving understanding of the Value of DER to D.

These two utilities are both very-large electric utilities in some of the nation's most populous states. Each company provides reliable, on-demand distribution service down to the smallest customer's meter. And each utility has experience in integrating different types of DERs onto its distribution system. There are differences between the two systems' physical configurations, however, which allows their case studies to represent the bookends of distribution-system design. SCE and Con Edison are working together by investing in analysis to better understand how the locational, temporal, and performance characteristics of DER for D interact with their distribution systems. Each utility is now working with EPRI to apply the Integrated Grid benefit/cost framework so as to elucidate some of the implications for providing cost-effective reliability solutions through DERs. This work is at its early stages, but is providing some preliminary insights which are summarized here.

FAQs about Con Edison and SCE

Let's start with some of the basic facts that characterize the two systems: Con Edison – considered the oldest electric distribution utility in the world (and home to the legacy of Thomas Edison's first central station located on Pearl Street in New York City's financial district) – provides electric service to approximately 3.3 million customers (and a population of approximately 9.2 million people) in New York City and Westchester County.[61] The system features approximately 94,000 miles of underground cable[62] (the largest underground system in the world) and a service territory covering 610 square miles (or less than 1 percent of New York State's total land area).[63] Con Edison, however, serves almost half of New York State's total population.[64] In New York State's restructured electricity market, Con Edison is primarily a wires-only company.

Figure 22:
Con Edison and NYISO Service Territories



Source: Con Edison and FERC

It is the delivery company for all of the loads in the NYISO market zones "I" and "J", with a combined summer peak load estimated to be 16,773 MW in 2016 (with that load level already adjusted for the impacts of energy efficiency and behind-the-meter generation).[65]

Con Edison has estimated that up at present, there are 259 MW of grid-connected DERs, of which 94 MW are renewable (mainly solar PV) resources.[66]

Figure 23:
SCE and CAISO Service Territories

Source: SCE and FERC.

Another 144 MW is currently in Con Edison's interconnection queue. Additionally, the Con Edison system has 491 MW of energy-efficiency and wholesale and retail demand-response resources capable of reducing Con Edison's system peak.[67]

By contrast, SCE covers a much larger and less-dense region: nearly a 50,000 square-mile area,[68] or approximately one-third of the land area of the State of California.[69] One of California's largest utilities and in operation for over 125 years, SCE distributes power to 5 million customers and a population of more than 14 million people in central, coastal, and southern California (excluding Los Angeles and some other cities). SCE serves approximately one third of California's population.

California's electric industry still allows electric utilities to own generation in some circumstances. SCE is partially vertically integrated, although with the 2013 closure of the San Onofre Nuclear Generating Station, over 80 percent of its incremental supply comes from third parties. At present, SCE estimates that the following DER capacity[70] is located on its system (whose 2016 peak demand is estimated to be 23,537 MW[71]):

Distributed Renewable Generation	1,998 MW
Energy Storage	7 MW
Electric Vehicles	57 MW
Energy Efficiency	1,122 MW
Demand Response	1,177 MW

Beyond the customer-driven DERs added in the Con Edison and SCE service territories, each of these utilities has conducted competitive solicitations that were either designed to procure DERs in order to delay or avoid anticipated local distribution system reliability concerns (as in the case of Con Edison) or allowed to contribute to the package of traditional and non-traditional resources needed to help mitigate the resource-adequacy impacts of the unexpected closure of a nuclear plant (as in the case of SCE).

State policy in California and New York

Con Edison and SCE share the common fact that they provide electric service in a state where utility regulators are actively pursuing pathways to facilitate much greater reliance on DERs in the future.

As part of its carbon-reduction goals, for example, California has aggressive clean-energy targets. California policy seeks to position DERs as a mainstream tool to help maintain local electric system reliability in the future. In 2013 California enacted AB 327 which, among other things, required SCE and the other investor-owned utilities to consider, as part of their distribution planning processes, non-utility-owned DERs as potential alternatives to utility investment and as part of ensuring reliable electric service at lowest cost.[72] AB 327 (Public Utilities Code § 769) required the utilities to file distribution resources plan in 2015 and indicate optimal locations for the deployment of DERs. SCE, along with the other two regulated utilities in California, filed their distribution resources plans

("DRPs") in July 2015.[73] California has adopted spreadsheet-style methodologies for estimating avoided costs DERs: the Distributed Energy Resources Avoided Cost Calculator, prepared by E3.[74]

California's AB 327 further directed the California Public Utilities Commission ("CPUC") to develop a new NEM program to go into effect by 2017, based on "electrical system costs and benefits to nonparticipating ratepayers."[75] The CPUC recently voted to continue NEM until 2019, having found that in light of "the analytic tools and information currently available for use by the Commission, it is not possible to come to a comprehensive, reliable, and analytically sound determination of the benefits and costs of the NEM successor tariff to all customers and the electric system."[76]

California currently has various proceedings underway to support the adoption of DERs as part of distribution-system planning and service provision: One docket (R.14-08-013) is focused on the development of methodologies to determine how DERs "can meet system needs as an alternative to traditional investments, provide justification for meeting those needs with distributed energy resources instead of conventional alternatives, define the services that may be bought and sold to meet the needs, and produce maps that indicate where distributed energy resources should be sourced."[77] Another docket (R.14-10-003) aims to support the "deployment of cost-effective distributed energy resources that satisfy distribution planning objectives."[78] Together these proceedings will address development and demonstration of competitive solicitation frameworks for DERs targeted to address distribution system reliability needs, as well as the utility's role in soliciting and/or providing DERs.

New York State's strong inclinations toward greater reliance on DERs are part of the state's on-going process to "Reform the Energy Vision." Starting in 2014, New York's REV process is attempting to change the state's "energy policy to put customers first and make sure energy efficiency, increased use of renewables, and reliance on more resilient distributed energy resources like microgrids are at the core of our energy system."[79] DERs play a central role in the REV platform: "NY's new regulatory compact demands that promotion of market-driven, clean-energy innovation is in front of and behind the meter."[80] The Commission has found that "achieving a more precise articulation of the full value of [DERs] is "a cornerstone REV issue."[81]

New York regulators recently adopted a benefit/cost framework through which New York utilities will need to determine when DERs are cost-effective relative to traditional distribution planning options.[82] In parallel, New York regulators decided in October 2015 to eliminate caps on new NEM customers until after the completion of proceedings (expected by the end of 2016) to establish values for DERs providing services to local distribution companies.[83] These proceedings aim to establish more precise approaches (compared to NEM) for valuing DER in markets in the long term, "and, most immediately, to define a near-term transition from NEM."[84]

SCE's and Con Edison's electric distribution systems; configuration differences and planning similarities

Apart from the many similarities between these two electric distribution systems, there are other important differences between Con Edison's and SCE's systems, with implications for understanding the Value of DER for D.

The first and most prominent distinction has to do with the physical configuration, or topology, of their distribution systems. Con Edison's and SCE's distribution systems are fundamentally different. SCE's distribution system resembles the more common 'radial' layout of distribution facilities, which resembles in simplest form a 'tree-like' configuration in which customers are served off of circuits that are like branches of trees (as shown conceptually in Figure 24 and as illustrated with distribution-system features in Figure 25).

Figure 24:
A Radial Distribution System Resembles a Tree

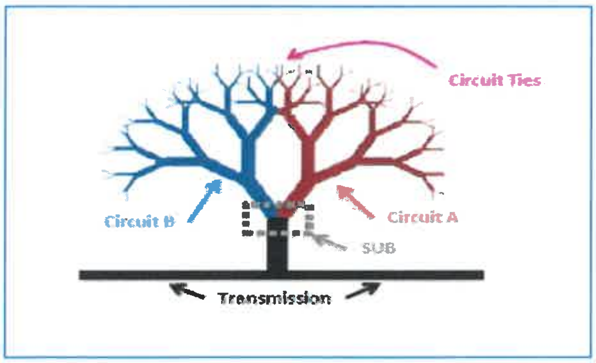
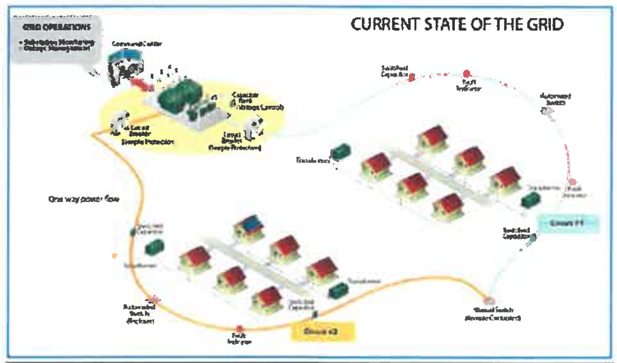


Figure 25:
Customers are Served Off of the System's Branches



Source: SCE

Con Edison's underground system in New York City is quite different from SCE's: "Although most areas of the country use simpler radial distribution systems to distribute electricity, larger metropolitan areas like New York City typically use networks to increase reliability in large load centers. Unlike the radial distribution system, where each customer receives power through a single line, a network uses a grid of interconnected lines to deliver power to each customer through several parallel circuits and sources. Power flows in multiple directions. This redundancy improves reliability, but it also requires more complicated coordination and protection schemes...."[85] Figures 26 and 27 shows the configuration of the Con Edison network.

Figure 26
A Network Distribution System Resembles a Mesh

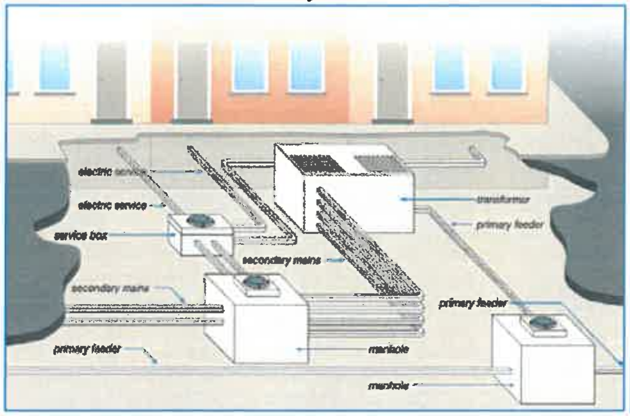
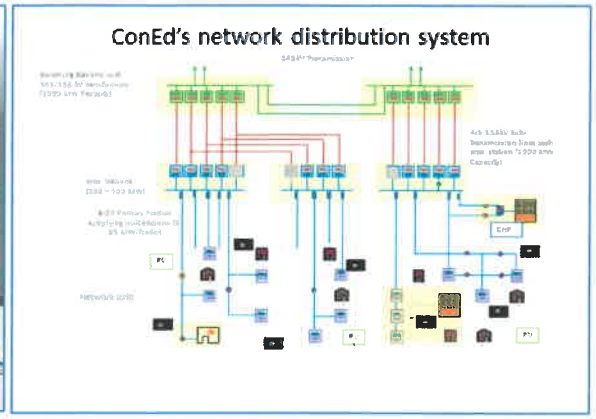


Figure 27
Customers are Served Off of Interconnected Wires



Source: Con Edison

In both systems, the distribution system changes over time, as a function of demand growth, the profile of demand over the course of a day, aging infrastructure, smart-grid investments, DER installations, upgrades to parts of the system/network, and so forth. Also in both types of systems, the utility conducts distribution-system planning (as described previously), to anticipate changing patterns and levels of electricity use that might affect the peak hour of use on a particular circuit or part of the network and to identify locations on the system where reliability violations will likely occur without a fix. The planner anticipates that a particular circuit or part of the network could become thermally overloaded, or experience voltage concerns, or otherwise violate reliability standards in the future. Traditionally, the distribution-system planner looks for actions and capital investments that minimize the overall cost of fixing the reliability problem while optimizing the use of existing capacity on the system.

Typically, the planner and system engineer would seek to solve an anticipated reliability problem so as to remedy the situation for several years (rather than only solving the problem in the most minimal way and having to resolve a greater need the following year to keep up with load growth). In this way, traditional planning has developed solution sets that provide headroom in the capacity once a major upgrade has occurred so as satisfy reliability requirements in planning cycles with solutions providing for multiple years of reliable distribution service. This occurs not just because traditional fixes tend to be lumpy investments, but also because of the goal of avoiding having to take steps year in and year out to keep up with the changing needs of the system.

Although the planner's tasks may be similar in radial and network systems, the toolkit of solutions – even traditional solutions, let alone non-traditional ones – varies across the two types of distribution systems. In a radial system, for example, the utility may be able to literally rewire the system's elements on a case-by-case basis and move some customers' loads from a soon-to-be overloaded circuit and on to a different circuit with greater load-serving capability. SCE's business-as-usual distribution planning recognizes this capability to rebalance loads before needing a larger capital investment. Figure 28a through 28c illustrate (using hypothetical data) how available distribution capacity in one part of a radial system (i.e., Figure 28a showing the SCE's "Merced" substation (serving the area shown in green) with 5 MW of anticipated capacity deficiency (i.e., anticipated load that exceeds planned capacity under high temperature and load growth). Available distribution capacity can be used to provide relief in neighboring parts of the system. Figure 28b shows potential sources of load relief in three areas: Lark Ellen (shown in yellow with 2 MW available), Bassett (shown in blue with 1 MW available), and Cortez (shown in purple with 2 MW available). Figure 28c shows the result of reconfiguring the system and shifting the loads in the deficient areas to become part of Merced, such that there is 1 remaining MVA in Merced after solving the reliability concerns in all three neighboring parts of the radial system.

Figure 28: Substation Load Growth Planning: Illustration of Load Balancing

Figure 28a: Problem Identification

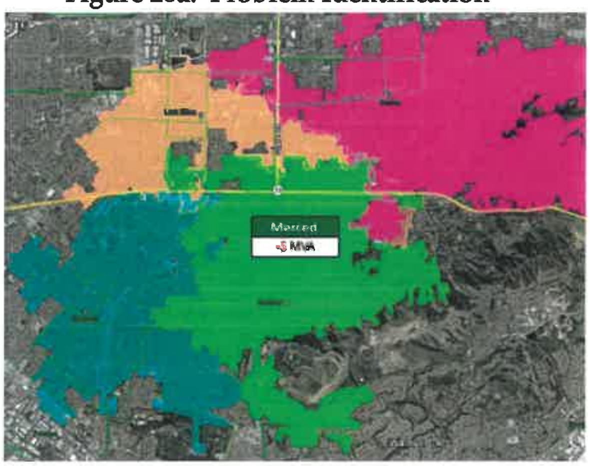
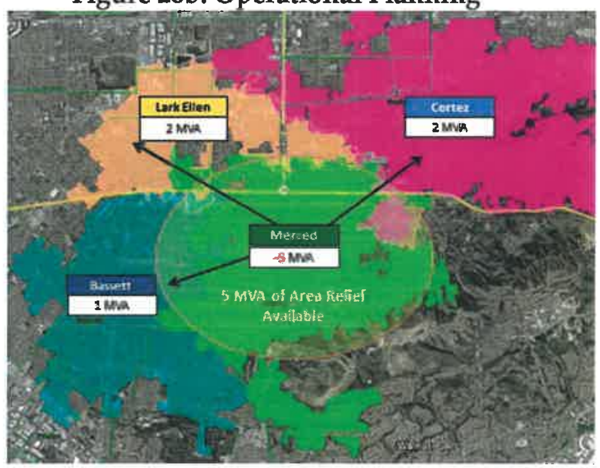
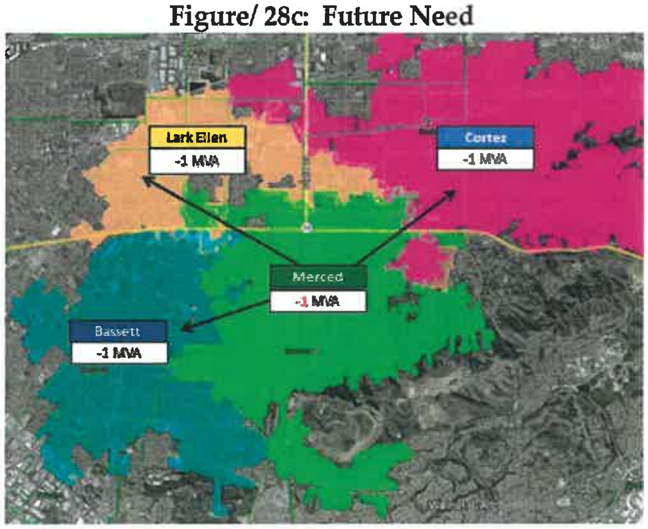


Figure 28b: Operational Planning



Figure/ 28c: Future Need



Source of illustrative diagrams: Erik Takayesu, SCE

There are various implications of this rebalancing tool for incorporating DERs into distribution-system planning and operations. First, in theory, DERs procured and installed across these neighboring regions have the potential to directly assist in mitigating reliability concerns in any of them, because of the flexibility of rebalancing the radial system. (That said, different DERs still have different impacts depending on technology and location on the system (e.g., proximity to the substation versus distance to the substation).) Rebalancing provides a relatively low-cost means to defer/mitigate problems (up to the point at which a new capital upgrade is triggered). This means that the avoided costs are relatively low in certain parts of the system at various points in time. This also has implications of Value of DERs to D over time given the dynamic and changing nature of the distribution system.

These types of strategies enable the utility with a radial system to defer or avoid making a larger capital investment to increase the capacity of the circuit. Doing something analogous would be more difficult and therefore more expensive on an underground network system, where such physical reconfigurations are economically constrained due to the complexities of the mesh system. On a network system, DERs located in one part of the network will have little ability to remedy a reliability problem located in a different part of the network. And DERs located within a network section may have diffused impacts, because the flows on the network move in so many directions.

In both types of distribution system, as noted previously, recall that most of the traditional fixes are capital investments. This suggests that the lion's share of avoided costs is in the area of avoided capacity investment. And this in turn suggests there will be opportunities to further experiment with and refine competitive procurements for DERs as the most productive market mechanism for identifying least-cost resources *as well as* price discovery for compensation.

As SCE and Con Edison each proceed to more routinely plan to integrate DERs into their distribution-system plans and solution sets, these utilities – like many others around the country – need to understand how DERs with different technological attributes, performance characteristics, costs, and integration impacts fit with the quite-local needs of each distribution system. Both SCE and Con Edison are working to better understand these locational, temporal, and performance characteristics of DER for D by investing in analytic tools to advance their understanding of the locational and temporal value of DERs at the local distribution level.

Both SCE and Con Edison have developed internal analytic tools to assess DERs in terms of how well they fit with the companies' needs. These tools take into account the duration of particular DERs' availability (e.g., four-hour battery, eight-plus-hour energy efficiency, two-hour demand response), their risk, their maturity, their flexibility and their ability to meet the particular parts of the system.[86]

And each is also now working with EPRI to apply its Integrated Grid benefit/cost framework so as to elucidate some of the implications for providing cost-effective reliability solutions through DERs. This work is just underway, but is providing some initial insights, as described briefly below

Insights from modeling of DERs in Con Edison and SCE distribution systems

EPRI modeling (overview)

EPRI has for several years been building a methodological framework for understanding the features of an integrated and modern grid.[87]

> The concept of an Integrated Grid was outlined by EPRI noting the goals to realize the full value of a transformed power system – its diverse inputs, efficiencies and innovation. An Integrated Grid should make it possible for stakeholders to identify optimal architectures and the most promising configurations, recognizing that solutions vary with local circumstances, goals, and interconnections.
>
> The question is about the ways in which DER interacts with the power system infrastructure. The formula for this answer has multiple dimensions. Beneficial and adverse circumstances can arise at differing levels of DER saturation. The interaction is dependent on the specific characteristics of the distribution circuits (design and equipment), existing loads, time variations of loads and generation, environmental conditions, and other local factors. Benefits and costs must be characterized at the local level and the aggregated level of the overall power grid.[88]

EPRI's methodology incorporates several features to help identify the potential for DERs to replace traditional investment, including: examining the hosting capacity of different spots on the distribution systems; running power-flow analyses with load-growth projections on particular parts of the system to see when reliability violations would occur; identifying a traditional fix to remedy those violations; relying on scenarios to explore the ability of different patterns of DER dispersion for solving those violations; and estimating the benefits and costs of the DER solutions compared to the traditional solutions. This methodology provides the potential for highly granular views into the locational value of DERs on specific distribution systems, taking into account the impact on the Value of DERs for D as well as the other values of DERs (for T, for G, and for S).

EPRI's preliminary modeling of Con Edison's and SCE's system

Con Edison, SCE and EPRI have developed a joint project to demonstrate the EPRI methodology and to understand implications of integrating DERs into distribution-system resource-adequacy plans and processes, with a focus on DER as "a distribution system adequacy resource." This larger project is described in the forthcoming EPRI report, "Time and Locational Value of Distributed Energy Resources (DER): Methods and Applications" (*EPRI # 3002008410)* (hereafter "EPRI's Time and Locational Value of DER Study").

As part of that joint project, EPRI has conducted preliminary analyses to apply EPRI's framework[89] to a handful of circuits on the two different SCE and Con Edison distribution-system configurations (i.e., SCE's radial system and Con Edison's network system). These preliminary applications (which will be described in EPRI's Time and Locational Value of DER Study) provide some initial insights about the roles DERs can play under certain conditions in different distribution-system types. These preliminary studies focus on discrete sections of each of the two utilities' distribution systems – the Williamsburg area of Con Edison's Brooklyn/Queens distribution system, and the Nogales Substation on the SCE system.

For both the modelled Con Edison network and SCE's circuits, EPRI evaluated two separate scenarios for DER deployment, with the two scenarios designed to be bookends for DER applications and situations that could be analyzed to provide a complete picture of DER impacts and implications.

In the first scenario, the traditional distribution-system investment is compared to a portfolio comprised of a mixed set of DERs that are strategically located on the local distribution system to solve the reliability violations. This was intended to simulate the performance of a utility procurement designed to induce DER entry into the market as part of an integrated distribution-system plan. The starting point of the initial scenario was a 2015 base case with an assumed load-growth in each year through 2025. EPRI ran power-flow analyses which identified places where reliability violations (e.g., thermal overloads and/or voltage problems) might occur in the absence of actions to address the anticipated reliability concerns. Where violations were identified, then the study identified a traditional utility solution to address and remedy each of the violations. For the same violations, two separate DER solution cases were evaluated: one in which a minimum quantity of DERs were assumed to be added just so as to solve the reliability violation and not produce any headroom on the system; and another one in which enough DERs were added to provide the same level of headroom as would be accomplished through the traditional (and typically more lumpy) system upgrade.

In the second scenario, a set of DERs was assumed to on the distribution system as a result of customer-driven actions (as compared to a utility procurement targeted in particular locations), with the DERs (all assumed to be solar PV) located randomly around the portion of the distribution grid being examined in the study. Those installations were assumed to result in certain equipment investments by the utility (to accommodate higher power flow, to mitigate the effect on local circuit voltage, and to resolve reverse power-flow effects on protection systems). Hosting capacity studies were relied upon to illuminate the impacts that needed to be addressed.

After developing these various solution sets for each utility's distribution-system examples, then EPRI prepared an economic benefit/cost analysis of each solution set: i.e., the traditional utility 'engineered solution' (e.g. upgrade); the targeted DER portfolio (at two levels of penetration – one set at a minimum amount of DERs to satisfy the reliability violation, and the other set at a level of DERs needed to provided comparable reliability and headroom as the utility's upgrade); and the randomly placed, customer-driven DERs. For the portfolio of DERs, the set of technologies was constructed so as to provide mitigation of reliability violations over multi-hour peak periods. EPRI shaped the energy profile of each DER case, depending on the DER technologies being analyzed.

For each distribution-system alternative, the costs of the distribution-system solution were compared to the benefits, using EPRI's framework that incorporates benefits in terms of any energy produced by DERs, any generating-capacity value, avoidance of losses on the transmission and distribution system, and avoided carbon prices. For the Con Edison analysis, for example, EPRI used NYISO forecasts of locational marginal prices ("LMPs") for energy and estimated avoided capacity market costs for zone J (New York City).

Preliminary results: The location and attributes of DERs matter greatly for their potential Value to D

Based on information provided by EPRI's Time and Locational Value of DER Study, the preliminary results vary across the two utility systems and across the different scenarios (and DER amounts).

- In Con Edison's network system, the analysis revealed that the placement of the DERs matters significantly in terms of the ability of a MW of DER to address a local reliability problem (e.g., a particular overloaded transformer): If all of the DERs could literally be positioned at the site of the overloaded transformer, they would have the biggest impact in terms of mitigating the problem. The farther the DERs are located relative to the problem on the network, the less impact a MW of DER has on solving the problem. This is due to the mesh character of the network itself which allows power to flow in multiple directions and which tends to disperse the impact of the DERs. Therefore, the more distributed (rather than surgically targeted) are the DERs, the more MWs are needed to remedy the reliability violation. And the more MW that need to be added, the more additional equipment (e.g., new SCADA systems) also needs to be added to address power flows. EPRI's analysis also elucidated another issue: the amount of DER that can be technically allocated to any single node or load point on the network. Availability is dictated by the kind of load or customer being served and how much DER can be physically located there. Because it is difficult, in practice, to add DERs literally at the transformer site itself, then it is likely that more, rather than less, DERs would be needed to solve a particular problem – with cost implications for the various alternatives.

- For the SCE case, where one objective in normal distribution-system planning is to maintain the operational flexibility associated with the circuit-rebalancing capability, this particular attribute of the system had to be taken into account when comparing the engineered solution relative to the other DER cases. When the DERs were targeted and placed at particular parts of the feeders where hosting capacity was available, the effectiveness of DERs in mitigating the reliability violations ended up providing less reliability relief than the randomly dispersed, customer-driven DERs; this resulted in part from the DERs being positioned in various parts of the radial system rather than a single location. EPRI's preliminary analysis indicated that: DER can provide directional relief for thermally constrained assets on a radial system, with DERs located downstream from the constrained asset potentially better able to provide relief. (That said, the location of a DER downstream of a constraint may change over time as a radial distribution system is reconfigured or rebalanced. So, distribution-system reconfiguration (a normal operational tool in radial distribution systems) can impact the locational value of DERs after they have been placed on to a system.) DER can provide bi-directional relief for voltage-constrained assets, with voltage support provided either downstream or upstream from constraint (bidirectional support) as long as the resource is located electrically close to the constrained area.

More broadly, here are the more general takeaways in EPRI's forthcoming study:

- **Individual DERs (and portfolios comprised of combinations of different DER technologies) have different and complex interactions with the electric system.** DERs have the potential to be a viable and economic alternative to a traditional utility-side investment to meet distribution system load growth requirements. To effectively defer and/or replace traditional distribution solutions, however, DERs must achieve equivalent characteristics of availability, dependability and durability.
- **DER impacts can be either beneficial or adverse, depending on a wide variety of contextual circumstances.** Each distribution system is geographically and electrically distinct from other utilities and has considerable variation within a single utility's system. This makes it difficult to generalize about the impacts of DERs; their impacts depend upon the specific characteristics of the DER technologies, the distribution circuits, existing loads, time variations of loads and generation, and other local factors. Detailed studies are needed to assess and fully understand the time and locational impacts of DERs for different utilities. Hosting capacity studies are an important analytical tool in understanding local system characteristics, and can provide a good directional indication of the amount of DERs that can be accommodated in particular places, although hosting capacity is likely to change over time for multiple reasons.
- **DER location, relative to a violation of a system limit, determines its effectiveness in relieving the violation.** In radial systems, DER location relative to the constraint is important from the perspective of energy losses, but there is only one path for power to flow on, and DER output can contribute directly to relieving the violation even at a distance as long as it is behind the violation (relative to the substation), not in front of it. In networked (mesh) systems, however, the output of DER disperses, flowing along many paths that go around the violation; the greater the electrical distance of the DER from the constraint, the

more its effect is dispersed. Network studies identified cases where the dispersion is relatively small (e.g., between 85-90 percent effective) as well as ones where it requires over 8 kW of DER to relieve 1 kW constraint.

- **Distribution reconfiguration can impact hosting capacity and locational value.** Where possible, DER can be allocated to relieve constrained assets; however, reconfiguration of the system to address possible violations of limits or other operational considerations alters power flows and may eliminate or defer the need for either utility investments or DER. Traditional upgrades or DER may be needed when reconfiguration is no longer able to prevent violations.
- **Benefits and costs of DERs need to be characterized at the local and bulk power system levels to estimate their full value.** Identifying localized benefits and costs can help distribution companies determine how best to utilize and accommodate DER as part of distribution-system planning and operations. Including costs and/or benefits that occur outside of the utility's operational and financial domain can help policy makers understand the consequences of alternative levels of DER penetration.
- **Advancements in distribution planning tools, models, and processes are needed to ensure the benefits of DER are fully realized while maintaining system reliability and performance.** This includes: studying customers' electrical demand to characterize their loads with more granularity and understand/forecast their inclination to adopt a DER technology and how they would use it; and probabilistic modeling to characterize the availability and variability of power supplied by DER to the customer and to the grid.
- **Integration of DER will require substantial changes in how distribution systems are designed and operated.**

Note that these results are preliminary. These early analyses, which are part of a larger and longer-term project, had to rely on simplifying assumptions, and were not able to be designed so as to optimize the value of DERs within the distribution systems. But they nonetheless illustrate how a number of factors (e.g., DER technology type, placement of DERs on different parts of distribution systems) affect the prospects for DERs to avoid a traditional utility solution and the costs of doing so. By design, EPRI's scenarios were bookend cases, examining the differences when customers decide to install PV systems as compared to the utility targeting the location of DERs designed explicitly to remedy local reliability problems on the distribution system. Even so, they highlight some of the challenges in developing estimates of the Value of DERs for D – and underscore the importance of moving from blunt valuation tools to ones that capture the different value of varied DER technologies located at different places on real distribution systems.

Conclusions: Insights for future considerations of the Value of DER to D

Rely on time-tested ratemaking principles to guide decisions about the Value of DERs for D

Although regulators, utilities, and stakeholders are working hard to refine benefit/ cost concepts and procurement/compensation arrangements for evaluating when and where DER installations provide net benefits, the principles of fairness and efficiency remain important in considering cost-allocation and compensation levels for DERs, and for developing ratemaking approaches for utilities.

Don't ignore the differences among DER technologies and their impacts on and contributions to the local grid in calculating their potential Value to D

Where particular DER technologies and applications enable reliable *distribution* service at lower cost than without that DER, then those particular DERs provide a Value of DER for D and to all of the utility's customers. DER's value to the electric system (and more specifically, to each of its component parts (D, T and G)), depends upon the location where DERs are placed on the grid and the timing, duration and quality of supply provided by a portfolio of DERs relative to the supply provided by the grid. Depending on the DER technologies, their attributes and the circumstances of their location and operation, a DER may have net benefits or net costs to the electric system.

Move beyond conceptual valuation frameworks that identify potential net benefits of DERs to D

There is a relatively robust literature on the appropriate conceptual framework to calculate values for DERs. Most studies have focused on the different components that affect a utility's avoided costs or on benefit/cost methodologies for determining when DERs are potentially more cost-effective than traditional investments. Avoided distribution costs tend to be relatively small compared to other avoided costs (e.g., energy, production capacity, environmental impacts). Yet determining the value of a particular DER application (or portfolio of DER technologies and applications) in specific distribution-utility contexts is likely to be relatively complicated and difficult to execute (compared to some of the other sources of value, where there are more transparent indicators of value). DERs' value to distribution systems will depend upon both the attributes of the portfolio of DERs and their location on particular distribution systems. More work is needed to illuminate this part of DER valuation proposition.

Transition distribution-system planning to incorporate DERs

As part of the evolution of the industry's understanding of the value of DERs, some state regulators and utilities are experimenting with how to integrate DERs into utilities' long-term, distribution-planning processes. These initiatives are attempting to identify where specific DERs have the potential to provide comparable functionality on the distribution system at a cost lower than traditional utility investment. Most of the traditional fixes to resolve anticipated local reliability problems are capital investments, many of which have long lead times that are taken into account in the utility's planning horizon and involve physical upgrades to reinforce the capability of the infrastructure to meet customers' needs. This suggests that at least in the early stages of the evolution, the focus of market design for DERs for D ought to ensure that DER capability is installed in sufficient amounts, locations, time frames, and attributes to assure that the DERs can provide the same functionality as would have been provided by a traditional utility solution.

Build upon prior PURPA experience that market-based mechanisms provide value to customers compared to relying on administratively determined avoided costs

Many states' experience in implementing PURPA indicated that customers benefitted when the industry transitioned from initial approaches (that relied upon prices established in administrative proceedings) to more market-based mechanisms for revealing avoided costs and the prices to be paid to winning suppliers. This experience offers important lessons for the current efforts to design methods to integrate DERs efficiently and effectively into distribution-utility plans and operations. Where the utility can fairly obtain and efficiently pay for the quantity/ timing/location of DERs needed at market-based, competitive prices (rather than at avoided cost), then there may be net benefits – i.e., value to the system and its customers. Thus the full economic value of DER to the grid and its customers may not be the same as the amount paid for DER. Competitive solicitations can reveal the portfolio of DERs with the attributes to satisfy the utility's local reliability requirements at lowest costs. The utility can then enter into contracts to assure that the winning DERs enter the market and help to resolve local reliability problems cost-effectively and reliably. The difference between full avoided costs and the costs to the utility (and its customers) is the value to consumers of having the utility incorporate and integrate DERs into its distribution-service solution set. Utility contracts with successful DER offerers should include payments in anticipation of delivered capacity (e.g., milestones for installation of the DERs), and for actual performance.

Start with forward contracting for DER capacity before focusing on operational DER markets

For now, the markets for DER for D are still in their very-early stages. Given that most potentially avoidable distribution-system costs are capital investments, it seems important to focus initial market-design attention on procuring DERs for their capacity value to distribution systems. In the future, as the markets for DER evolve, it may be worthwhile to look at the other shorter-term/ operational sources of value of DER to D, and then refine operational markets to compensate contracted resources for performance and for other services provided by DER to D. After the main source of value (distribution capacity) is realized, then these other value streams can be layered on top of that foundation. This prioritization of "DER-for-D" market elements – starting with a focus on forward procurements of capacity, and then moving toward secondary (and likely smaller) transactional markets over time – fits with economic principles about the conditions that enable robust, successful markets to exist (and which, if absent, inhibit markets from delivering efficient prices). These conditions are not yet in place (much less fully designed) for the market for DERs.

ENDNOTES

[1] Sue Tierney is a senior advisor at Analysis Group, and formerly assistant secretary for policy at the U.S. Department of Energy, Massachusetts' Secretary of Environmental Affairs and a commissioner at the Massachusetts Department of Public Utilities. For over two decades as a consultant, she has worked for a wide variety of clients, including energy customers, environmental groups, state agencies, grid operators, electric and natural gas utilities, competitive suppliers, power generators, foundations, and others. Knowing that she is a supporter of efforts to lower carbon emissions from the power sector and of competitive and reliable power markets, Con Edison and SCE approached her to write this report on the value of distributed energy resources for distribution systems, for which she retained editorial control.

[2] There is no consistent definition of "DER," in terms of technology or the size/location of the resources. For example:

- Bloomberg New Energy Finance ("BNEF") tracks "Distributed Power, Storage, and Efficiency," which includes: small-scale renewables, CHP and waste heat and power ("WHP"), fuel cells, storage, smart grid/demand response, building efficiency, industrial efficiency (aluminum), and direct use applications for natural gas." BNEF, "Sustainable Energy in America: Fact Book," 2016, page 5.
- The Rocky Mountain Institute's e-Lab includes the following as DERs: (a) end-use energy efficiency; (b) distributed generation (small, self-contained energy sources located near the final point of energy consumption, such as solar PV, CHP, small-scale wind, fuel cells); (c) "distributed flexibility & storage" (a collection of technologies that allows the overall system to use energy smarter and more efficiently); and (d) "distributed intelligence" (technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration). e-Lab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, Second Edition, 2013, page 8.
- Navigant includes a wide variety of resource that can be utility-owned on the grid "in front of the meter" or customer-owned "behind the meter": distributed solar, wind, micro turbines, fuel cells; distributed storage (electromechanical, mechanical, thermal); microgrids; demand-response (direct load control, price based, incentive based, virtual power plants); utility-side loss reduction (conservation volt reduction; volt/VAR optimization; grid optimization); and electric-vehicle battery charging and discharging. Jan Vrins, "Distributed Energy Resources: Lead or Follow," Aspen Institute Energy Policy Forum, July 28, 2015.
- The Electric Power Research Institute ("EPRI") defines DER as "fulfilling the first criterion (Item 1), in addition to any one of the second, third, or fourth criteria as follows: 1. They are interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV). 2. They generate electricity using any primary fuel source. 3. They store energy and can supply electricity to the grid from that reservoir. 4. They involve load changes undertaken by end-use (retail) customers specifically in response to price or other market-based inducements." EPRI, "The Integrated Grid: A Benefit-Cost Framework," Final Report, February 2015, page 1-3.

[3] This deep literature addresses a wide set of important policy topics: the role of NEM as a vehicle to stimulate development of rooftop solar projects; the impacts of NEM designs, in terms of whether participating customers are paying their fair share of electric system costs; the implications for distribution-system and bulk-power system operations of increasing penetrations of distributed and non-dispatchable renewable resources; transitional designs of pricing and procurement strategies to assure that DERs compete fairly with traditional central-station utility and non-utility projects; and many more. More generally, see: Travis Lowder, Paul Schwabe, Ella Zhou, and Douglas Arent, "Historical and Current U.S. Strategies for Boosting Distributed Generation," National Renewable Energy Laboratory ("NREL") and Joint Institute for Strategic Energy Analysis ("JISEA"), August 2015.

[4] See, for example: https://www.irs.gov/uac/Energy-Incentives-for-Businesses-in-the-American-Recovery-and-Reinvestment-Act; http://energy.gov/savings/residential-renewable-energy-tax-credit; http://solaroutreach.org/wp-content/uploads/2015/03/CommercialITC_Factsheet_Final.pdf; http://energytaxincentives.org/business/solar.php.

[5] See the Database of State Incentives for Renewables & Efficiency ("DSIRE"), which describes the many types of incentives that exist to encourage renewable resources. Summary tables of incentives by state (including not only RPS standards, but also tax credits, feed-in tariffs, property-assessed financing approaches, and other policies) can be found at http://programs.dsireusa.org/system/program/tables. The listing of states with targeted renewable energy credits for solar PV, for example, is found at http://programs.dsireusa.org/system/program?type=85&.

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[6] The California Public Utility Commission and California Energy Commission have a joint effort to encourage the installation of 3,000 MW of solar systems on homes and businesses through 2016. http://www.gosolarcalifornia.ca.gov/about/index.php. New York State has a "NY-Sun" initiative that provides incentives for relatively small-scale solar installations. http://ny-sun.ny.gov/About/NY-Sun-FAQ.

[7] North Carolina Clean Energy Technology Center, "The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report," February 2016 (hereafter, "50 States of Solar Study"), page 9.

[8] Shayle Kann, GTM Research, "Executive Briefing: The Future of U.S. Solar – Getting to the Next Order of Magnitude," November 2015, page 5. Also: "Throughout the first three quarters of 2015, 30 percent of all new electric generating capacity brought on-line in the U.S. came from solar. As of Q3 2015, more than 50 percent of all states in the U.S. have more than 50 megawatts of cumulative solar PV installed. Totaling 18.7 gigawatts, the current utility PV development pipeline is greater than all U.S. PV installations brought on-line through the end of 2014." Mike Munsell, "US Solar Market Prepares for Biggest Quarter in History," GreenTech Media, December 9, 2015.

[9] Energy Information Administration ("EIA"), 2014 summer generating capacity, with net capacity additions in 2015 .

[10] This forecast assumes the extension of the Production Tax Credit ("PTC"); the project pipeline for installations to come on line in 2016 was relatively high, in light of the uncertainty that existed throughout most of 2015 with regard to whether Congress would extend the PTC (which it did in December 2015).

[11] This cumulative capacity (906 MW of distributed wind) as of the end of 2014 reflects 74,000 wind turbines deployed across all 50 states, Puerto Rico, and the U.S. Virgin Islands. The authors of the "2014 Distributed Wind Market Report" define distributed wind "in terms of technology application based on a wind project's location relative to end-use and power-distribution infrastructure, rather than turbine or project size. Distributed wind is (1) The use of wind turbines, either off-grid or grid-connected, at homes, farms and ranches, businesses, public and industrial facilities, or other sites to offset all or a portion of the local energy consumption at or near those locations, or (2) Systems connected directly to the local grid to support grid operations and local loads." Alice Orrell and Nikolas Foster, "2014 Distributed Wind Market Report," Prepared for the U.S. Department of Energy by the Pacific Northwest National Laboratory, August 2015.

[12] Alliance to Save Energy, "The History of Energy Efficiency," Alliance Commission on National Energy Efficiency Policy, January 2013, page 3.

[13] "By 2030 the average household would save $1,039 per year in energy costs, net of the investment required to deliver those energy savings. That is roughly the same as what the average American household spends on education and nearly as much as average household spending on medicine and produce combined. American business would save $169 billion a year, almost as much as the corporate sector paid in federal income tax in 2011." Alliance to Save Energy, "Energy Productivity 2030," Alliance Commission on National Energy Efficiency Policy, February 2013, page 27, citing modeling analysis performed by the Rhodium Group for the Alliance Commission.

[14] In some states, CHP fueled by natural gas are not considered as DERs. In some states, such as California, DERs are intended to be renewable or load shifting resources only.

[15] Eric Wesoff and Jeff St. John, "Breaking: SCE Announces Winners of Energy Storage Contracts Worth 250MW," GTM (GreenTech Media), November 5, 2014.

[16] Con Edison GreenTeam, "Brooklyn Queens Demand Management Program Update Briefing," August 27, 2015.

[17] FERC v. Electric Power Supply Ass'n, 136 S.Ct. 760 (2016).

[18] See, for example: Karl Rabago, Leslie Libby, Tim Harvey, Benjamin Norris, and Thomas Hoff (Clean Power Research (CPR)), "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator," 2012.

[19] E3, "The Benefits and Costs of Net Energy Metering in New York," prepared for the New York State Energy Research and Development Authority and the New York State Department of Public Service, December 11, 2015 (hereafter referred to as "E3 NY Study"). E3 analyzed several scenarios that allowed for comparisons between the current NEM policy (that does not target solar PV systems to any particular location) and a modified approach that would target such systems toward locations where they could help to avoid distribution-utility investments in the local grid. Using a societal cost test, the targeting shifted the total benefit-cost ratio from 0.91 for downstate utilities and 0.98 for upstate utilities in the 'untargeted'

scenario, to 1.04 (downstate) and 1.08 (upstate) in the 'targeted' scenario. See, for example, pages 55-56 of the E3 NY Study. In the Con Edison service territory, the study indicated the following results: for the residential class, targeting the location of solar PV did not allow the systems to lead to positive benefits: the benefit-cost ratios were 0.80 (untargeted) and 0.82 (targeted). For the non-residential customer class, the benefit-cost ratios were higher and benefitted from targeting: 0.97 (untargeted) and 1.13 (targeted). See pages 96-98 of the E3 NY Study. One of E3's conclusions is that "NEM is a key component of the policy to encourage distributed renewable generation in New York, most especially solar PV. However, while NEM offers a simple and understandable tool for consumers, it is an imprecise instrument with no differentiation in pricing for either higher or lower locational values or higher or lower value technology performance (e.g. peak coincident energy production). The costs and benefits of NEM should be monitored given the fast evolution of this market…" E3 NY Study, page 7.

[20] 50 States of Solar Study, pages 9-16.

[21] 50 States of Solar Study, pages 17-18, 40-48. Also: NEM "has come under criticism recently for creating a 'cross subsidy.' That is, because solar customers are paying lower electricity bills under net metering regimes, utilities with a large portion of solar customers are faced with a shrinking customer base from which to recoup their fixed costs (e.g., the costs associated with maintaining the transmission and distribution infrastructure). Utilities have argued that solar customers do not pay their fair share to maintain the grid, and the fixed costs are being unevenly allocated to the non-solar customers in the service territory. (Wellinghoff and Tong 2015,) This argument has gained traction at the state public utility commission (PUC) and legislative levels, and by the end of 2014 there were over 20 ongoing proceedings that were examining either net metering or rate design to ensure that utilities could protect themselves against the adverse cost implications of high penetrations of customer-sited solar (GTM/SEIA 2015). Options proposed by utilities, PUCs, and state governments to deter some of these implications include: including fixed charges on solar customers' bills…; reducing the net metering credit; adopting a VOST [Value of Solar Tariff]…; redesigning rates…; imposing a minimum bill…; allowing for utility ownership of solar assets…; [and] transitioning utilities to be aggregators of distributed energy resources for delivery to grid operators. Travis Lowder, Paul Schwabe, Ella Zhou, and Douglas Arent, "Historical and Current U.S. Strategies for Boosting Distributed Generation," National Renewable Energy Laboratory/Joint Institute for Strategic Energy Analysis, August 2015.

[22] Hawaii State Energy Office, http://energy.hawaii.gov/wp-content/uploads/2011/10/HSEO_FF_May2015.pdf.

[23] Herman Trabish, "Hawaii PUC chair defends landmark decision to end retail rate net metering," Utility DIVE, October 26, 2015.

[24] EIA, "Hawaii's electric system is changing with rooftop solar growth and new utility ownership," *Today in Energy*, January 27, 2016, and "EIA electricity data now include estimated small solar PV capacity and generation," *Today in Energy*, December 2, 2015; Herman Trabish, "What comes after net metering: Hawaii's latest postcard from the future," Utility DIVE, October 22, 2015.

[25] New York regulators' decision effectively eliminated NEM caps that covered both residential rooftop solar and ground-mount projects typically associated with remote and community net metering. The New York Public Service Commission ("NY PSC") ordered stated that:

> a transition from net metering to a more accurate means of pricing and recognizing the value of DER, including PV and other forms of net metered generation, is expected in REV [Reforming the Energy Vision]. The Ratemaking Whitepaper, while affirming that net metering should remain in place for mass market customers at this time, and perhaps in other applications, notes that reforming rate design and DER compensation mechanisms, including net metering, can be accomplished upon "a strong foundation of the system value that DERs can provide." That foundation for the more robust pricing of DER is being built, opening net metering to replacement with mechanisms that more accurately price the value of DER.
>
> Valuation is being pursued on several fronts. First, studies on the benefits and costs of net metering are underway, as identified in the NY-Sun Order and as required by the recently enacted PSL §66-n. The completion of those studies is expected by the end of this year. Second, principles for conducting the benefit-cost analyses essential to properly valuing DER were set forth in the BCA Whitepaper, which presents a proposed framework for conducting a benefit-cost analysis and identifies key parameters within that framework. The analysis framework would assist in devising

means for valuing and compensating behind-the-meter generation and other features of REV. Comments on the BCA Whitepaper have been solicited, and consideration of the issues it raises is expected in the coming months.

Third, the necessary components to properly valuing the benefits of DER, as addressed in the Ratemaking Whitepaper, are its energy value, established in power markets at the location-based marginal price (LMP), and its value to the electric distribution system. This "value of D" can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance. While the LMP is well established and transparent, the "value of D" is not.

The Community DG Order and the Ratemaking Whitepaper, however, note the importance of developing the "value of D," while the BCA Whitepaper analyses and comments inform the consideration of the "value of D." As discussed further below, a process will be created that ties these efforts together such that a resolution of "value of D" issues can be expected in 2016. While the development of the tools and methodologies required to fully implement an approach based on "value of D" is likely a long-term effort, there is sufficient time to develop and adopt more precise interim methods of valuing DER benefits and costs, as well as the design of appropriate rates and valuation mechanisms, before December 31, 2016. Those interim methods will serve as a bridge while the "value of D" tools and methodologies are developed.

New York PSC, "Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation," Case 15-E-0407 - Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, pages 8-9 (original footnotes omitted). A petition for rehearing is pending.

[26] Krysti Shallenberger, "Nevada regulators approve new net metering policy, creating separate rate class for solar users," Utility DIVE, December 22, 2015. Julia Pyper, "Nevada PUC to Reconsider Grandfathering Rooftop Solar Customers Into New Net-Metering Policy," GreenTech Media, January 21, 2016.

[27] Krysti Shallenberger, "California regulators preserve retail rate net metering in 3-2 vote," Utility DIVE, January 28, 2016. Note that in March 2016, the three California investor-owned utilities and TURN appealed the CPUC decision.

[28] Herman Trabish, "Maine utilities, solar advocates back new bill to replace net metering, grow solar," Utility DIVE, February 25, 2016.

[29] State of Maine Office of Public Advocate and Strategm, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016. http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf. See also: Herman Trabish, "How Maine's power players are reacting to its pathbreaking new solar proposal: The first hearings on a plan to replace net metering with market-based incentives were held in the legislature last week," Utility DIVE, March 24, 2016.

[30] In Bonbright's original book in 1961 (as compared to the Second Edition of his book, co-edited by James Bonbright, Albert Danielsen, and David Kamerschen in 1988), Bonbright uses the following language to describe the three primary objectives of ratemaking and the 'criteria of a sound rate structure': "(a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and (c) the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received." James Bonbright, Principles of Public Utility Rates," 1961, page 292.

[31] 18 CFR 292.101.

[32] See: Frank Graves, Philip Hanser, Greg Basheda, "PURPA: Making the Sequel Better than the Original," prepared by Brattle Group for the Edison Electric Institute, December 2006. This paper analyzes the PURPA experience, which certainly helped to foster the development of competitive generation markets but in some cases nonetheless led to situations where: rates were actually set above avoided costs (e.g., New York State's 6-Cent Law); capacity payments were built into PURPA rates, even in situations where the utility did not need new generating capacity, such that the utility ended up paying more than it needed to; standard offer PURPA rates lacked quantity limits, which led to oversupply of capacity in the region; long-term contracts were signed at rates established by administrative (and not competitive or market-based) processes; and

utilities paid the same rates to all PURPA facilities even if their generation profiles had very different characteristics with varied implications for their goodness-of-fit with the utility's supply portfolio.

[33] e-Lab, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, Second Edition, 2013 ("e-Lab 2013 Solar Study").

[34] E3 NY Study, page 43.

[35] According to e-Lab, the other gaps in the methodological literature are twofold: (a) "Grid support services value: There continues to be uncertainty around whether and how DPV can provide or require additional grid support services, but this could potentially become an increasingly important value." And (b) "Financial, security, environmental, and social values: These values are largely (though not comprehensively) unmonetized as part of the electricity system and some are very difficult to quantify." e-Lab 2013 Solar Study.

[36] The categories of valuation in the 2012 Austin, Texas study (K. Rabago, B. Norris and T. Hoff, "*Designing Austin Energy's Solar Tariff Using A Distributed PV Calculator,*" Clean Power Research & Austin Energy, 2012), are described as follows by e-Lab:

- "Energy: DPV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).
- System Losses: Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.
- Generation Capacity: Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.
- Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.
- T&D Capacity: Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.
- Environmental: PV output times Renewable Energy Credit (REC) price—the incremental cost of offsetting a unit of conventional generation."

e-Lab 2013 Solar Study, page 55.

[37] The categories of valuation in the 2012 New Jersey/Pennsylvania study (R. Perez, B. Norris, and T. Hoff, "*The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,*" Clean Power Research, 2012) are described as follows by e-Lab:

- "Energy: Fuel and O&M cost savings. PV output plus loss savings times marginal energy cost, summed for all hours of the year, discounted over PV life (30 years). Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (assumed to be a combined cycle gas turbine ["CCGT"]). Assumed natural gas price forecast: NYMEX futures years 0-12; NYMEX futures price for year 12 x 2.33% escalation factor. Escalation rate assumed to be the same as the rate of wellhead price escalation from 1981-2011.
- Generation Capacity: Capital cost of displace generation times PV's effective load carrying capability (ELCC), taking into account loss savings.
- T&D Capacity: Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load. In this study, T&D values were based on utility-wide average loads, which may obscure higher value areas.
- Fuel Price Hedge Value: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The value is directly related to the utility's cost of capital.
- Market Price Reduction: Value to customers of the reduced cost of wholesale energy as a result of PV installation decreasing the demand for wholesale energy. Quantified through an analysis of the supply curve and reduction in demand, and the accompanying new market clearing price.
- Security Enhancement Value: Annual cost of power outages in the U.S. times the percent (5%) that are high-demand stress type that can be effectively mitigated by DPV at a capacity penetration of 15%.
- Social (Economic Development Value): Value of tax revenues associated with net job creation for solar vs conventional power generation. PV hard and soft cost /kW times portion of each attributed to local jobs, divided by annual PV system energy produced, minus CCGT cost/kW times portion attributed to local jobs divided by

annual energy produced. Levelized over the 30 year lifetime of PV system, adjusted for lost utility jobs, multiplied by tax rate of a $75K salary, multiplied by indirect job multiplier.

- Environmental: Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx / NOx emissions, mining degradations, ground-water contamination, toxic releases and wastes. etc...as calculated in several environmental health studies."

e-Lab 2013 Solar Study, page 58.

[38] The categories of valuation in the 2012 California study (Energy and Environmental Economics, Inc. ("E3"), "Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment. March 2012, prepared for the California Public Utility Commission, 2012) are described as follows by e-Lab:

- "Energy: Estimate of hourly wholesale value of energy adjusted for losses between the point of wholesale transaction and delivery. Annual forecast based on market forwards that transition to annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets. Hourly forecast derived based on historical hourly day-ahead market price shapes from CAISO's MRTU system.
- System Losses: Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.
- Generation Capacity: In the long-run (after the resource balance year), generation capacity value is based on the fixed cost of a new CT less expected revenues from real-time energy and ancillary services markets. Prior to resource balance, value is based on a resource adequacy value.
- T&D Capacity: Value is based on the "present worth" approach to calculate deferment value, incorporating investment plans as reported by utilities.
- Grid Support Services (Ancillary Services): Value based on the value of avoided reserves, scaling with energy.
- Carbon: Value of CO2 emissions, based on an estimate of the marginal resource and a meta-analysis of forecasted carbon prices.
- Solar Cost -The installed system cost, the cost of land and permitting, and the interconnection cost"

e-Lab 2013 Solar Study, page 50.

[39] The categories of valuation in the 2013 Colorado study (Xcel Energy, Inc., "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System," May 2013) are described as follows by e-Lab:

- "Energy: Costs are calculated on a marginal basis using ProSym hourly commitment and dispatch simulation using the TMY2 data set. The variable costs include fuel, variable O&M, and generation unit start costs. ProSym simulation implies DPV tends to primarily displace generation that is blend of an efficient CC unit (7 MMBtu/MWh) and a less efficient CT (10 MMBtu/MWh) through 2035. It is noted that, through 2017, DPV displaces a mix of gas-fired and coal-fired generation (before coal is retired in 2017).
- System Losses: Avoided T&D lines losses were assumed to achieve savings in energy, emissions, fuel hedge value and generation capacity. Distribution line losses were estimated using actual hourly feeder load data for the 58 feeders that represent 55% of DPV generation, and using an estimated value for the remainder. Average distribution losses were used to estimate savings from energy, emission & hedge value, and on a peak basis for generation capacity. Transmission line losses, based on annual, DPV generation-weighted values, were used to calculate energy, emissions, and hedge value, whereas avoided generation capacity was based on losses incurred across top 50 load hours.
- Generation Capacity: Avoided generation capacity costs are based on the market price of capacity until 2017, and after that (because of incremental need) based on the economic carrying charge of a generic CT's capital and fixed O&M costs. The avoided generation capacity cost is credited to DPV based on a ELCC study (historical system load and solar generation patterns for 2009 and 2010).
- T&D Capacity: DPV is assumed to defer distribution feeder capital investment by 1 to 2 years only if the existing feeder's peak load is at or near the feeder's capacity and the feeder's peak load is decreased by ~10%.

- Fuel Price Hedge Value: While the study notes the approach taken in other benefit/ cost studies to estimate fuel price hedge value from NYMEX fuel price forecasts, it is not explicitly stated how the fuel price hedge was ultimately estimated.
- Carbon: Annual tons of CO2 emissions avoided by DPV as calculated by the ProSym avoided cost case simulations. Change in marginal emissions over time driven by planned changes in generation fleet (primarily retirement of 1,300 MW coal in 2017).
- Solar Cost: Defined as "Integration Costs," or "costs that DPV adds to the overall cost of operating the Public Service power supply system based on inefficiencies that arise when the actual net load differs from the day-ahead forecasted net load." These costs are composed of electricity production costs levelized over 20 years."

e-Lab 2013 Solar Study, page 48.

[40] The Utility Cost test: Are the utility's costs higher or lower with the DER resources as compared to the utility's other benchmark investment? The Total Resource Cost test: Is the sum of the utility's costs and the participating DER customer's costs higher or lower than the utility's other benchmark investment? The Participating Customer Cost test: Will the customer have higher or lower electricity bills with DER than without it, taking the costs of DER into account? The Ratepayer Impact Measure/Non-Participating Customer Cost test: Will the utility's rates be higher or lower with the DER than with the utility's other benchmark investment? The Societal Cost test: Does the DER resource lead to higher or lower total costs to society, taking into account all costs and benefits (including externalities, DER costs relative to the utility's benchmark investments)?

[41] As noted previously, customer-driven DERs have resulted over the years from a combination of factors, most notably including the state regulatory policies noted previously (e.g., net-energy metering and tax incentives for solar PV investments and installations, 'loading-order' requirements favoring energy efficiency and so forth) and as well as the fundamental changes that have occurred in DER technologies/options, declines in equipment and installation costs, and the economic value proposition they provide to customers and third parties.

[42] Examples of such opt-in tariffs and rates include:

- NEM tariffs that focus on customers that elect to adopt of solar PV, without necessarily targeting installations toward various locations on the distribution system where such PV systems provide services in support of the grid.
- Time-of-use rates that aim to shift demand to off-peak periods (and thus potentially defer and/or avoid upgrades on the distribution system (and on other elements of the electric system)).
- Tariffs that permit the utility to exert operational control over particular equipment (e.g., air conditioning equipment; water heater equipment) on a customer's premises, again to shape the timing and level of demand on the system.
- Value-of-solar tariffs (like the one available in Minnesota), which allow a customer with rooftop PV panels to receive payments for the panels' output at a predetermined price, in conjunction with the customer taking service at the regular retail rate. http://www.nrel.gov/tech_deployment/state_local_governments/basics_value-of-solar_tariffs.html.

[43] "Hosting capacity is the amount of DER that can be accommodated in a system without any needs for upgrade. Distribution system level DER integration is constrained by thermal loads, power quality and protection schemes." Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart, Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015, page 24.

[44] "In December 2014, the PSC approved a first-of-its kind initiative in Con Edison's territory that illustrates certain principles underlying the new regulatory paradigm. Under this program, instead of building a new substation at an estimated cost exceeding $1 billion, Con Edison will be deploying local clean energy resources such as energy efficiency, renewables, and storage to meet system constraints, at a substantially lower total projected cost. This Brooklyn/Queens Demand Management Program serves as a tangible example of how new approaches can create 'win-wins.' Managing electrical demand (by shifting and reducing consumption) can reduce GHG emissions while improving the efficiency of the overall system and lowering the cost of maintaining the grid for all ratepayers." New York State, "Energy to Lead: 2015 New York State Energy Plan," page 58. See also: Con Edison, "Request for Information: Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements," issued July 15, 2014, which describes (on pages 2-3) the intention to solicit responses from qualified parties stating their interest and qualifications to supply Con Edison with new Demand Side Management (DSM) measures within the targeted load areas served by the Brownsville No. 1 and Brownsville No. 2 substations. These

substations support the Richmond Hill, Crown Heights, and Ridgewood networks. Brownsville No. 1 and Brownsville No. 2 area substations are forecasted to be overloaded under normal conditions. The targeted network map can be found in Appendix A. Operational measures will be employed by the Company to address overloads in years 2014 and 2015. However, due to the inherent temporary nature of the operational measures, a permanent solution is required to address the forecasted summer overloads and defer the need to build traditional utility infrastructure, namely a new area sub-station. Customer and utility side "alternative" solutions are planned to delay the need for the traditional infrastructure solutions. These solutions are needed to address forecasted summer overloads in 2016 (18 MW overload), 2017 (49 MW overload), and 2018 (58 MW overload). This RFI is the first step in identifying and pre-qualifying contractors for receipt of future RFPs and/or other purchasing actions for specific MW reduction needs, associated targeted geographic areas, and need dates. As the sub-transmission constraint is currently subject to potential overload, solutions that can be deployed rapidly, and with operational confidence, will be given greater consideration. This RFI is seeking information from innovative solutions providers for potential DSM multiyear "firm contracts" for pre-determined MW needs and delivery.
Targeted areas and characteristics of the Brownsville substations load pockets, where relief is needed, are included in Appendix B. Timing and duration of load reduction needs have been identified as the summer peak load occurring over the months of June through September, Monday to Friday, during the hours of 12pm to 12 am. A graph of the time of day in which the summer peak overload would occur is included in Appendix C.

[45] State of Maine Office of Public Advocate and Strategm, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016. http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf.

[46] This diagram results from conversations with Eric Takayesu from SCE on the value for DERs for D.

[47] e-Lab 2013 Solar Study.

[48] Many observers have pointed out the expectation that as the penetration of DER (especially solar) increases, each additional increment of DER will have diminishing value to the system. See, for example: Andrew Mills and Ryan Wiser, "Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels," LBNL, March 2014.

[49] EPRI, "Integrated Grid: A Benefit/Cost Framework," Final Report, February 2015, page 2-3.

[50] More than 80 percent of distribution-feeder-level investments planned and deployed on 1-2 year cycles, and "Substation and system-wide technology deployment planning horizon [is] between 5-7 years." Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart: Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015.

[51] See, for example: Paul Denholm, Robert Margolis, Bryan Palmintier, Clayton Barrows, Eduardo Ibanez, Lori Bird, and Jarett Zuboy, "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System," Prepared by the *National Renewable Energy Laboratory* under Task No. SS13.1040. Chapter 8.

[52] "Customers and services firms should know what types of services and benefits they can provide to the grid through access to relevant information, as compensation for these services may comprise a necessary element of the DER providers' business plans to obtain project financing. This also includes rules for the physical interconnection of new resources, whether principles of "open access" should apply and, if so, how they are specified and enforced. Boundary questions need to be addressed, such as whether DERs can participate in the wholesale transmission-level market directly, or must go through a distribution operator or load serving entity (LSE)42 that would provide the wholesale market interface." Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, pages 24-26.

[53] Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, page 52.

[54] There are lessons from academic research suggesting that disclosure of such costs works to the disadvantage of the utility and can result in higher retail electricity prices. See, for example: Timothy Cason and Charles Plott, "Forced Information Disclosure and the Fallacy of Transparency in Markets," *Economic Inquiry*, Vol. 43, No. 4, October 2005, 699-714.

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[55] See, for example, Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for NARUC and funded by the U.S. Department of Energy, 2008.

[56] As the market for DERs transitions to more competitive pricing in the future, the goal should be to design markets so as to produce efficient prices. This tendency is similar to what can occur in "pay as bid" versus clearing-price auctions in wholesale power market, with the former leading to bidders raising their offer prices and the latter leading to offer prices that are as low as possible. Efficient prices tend to flow from the latter, relative to the former. See Susan Tierney, Todd Schatzki, and Rana Mukerji, "Uniform-Pricing versus Pay-as-Bid in Wholesale Electricity Markets: Does it Make a Difference?" March 2008.

[57] See the informative discussion of distribution operational markets in the recent paper by Paul De Martini, Lorenzo Kristov and Lisa Schwartz, "Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight," LBNL, Report No. 2, October 2015, pages 24-26 (on markets and market services).

[58] One of the elements of the Maine proposal is an aggregator that can treat DERs as a fleet. See the presentation by Tim Schneider, Lisa Smith, and Lon Huber, "A Ratepayer Focused Strategy for Distributed Solar in Maine," NASEO Policy Outlook Conference, February 11, 2016http://energyoutlook.naseo.org/Data/Sites/8/media/presentations/Smith-NASEO-Solar-Policy-Framework-Maine.pdf. The white paper explaining the proposal in greater detail indicates that "this framework uses market forces to maximize value to all ratepayers, while fairly compensating solar adopters….The policy presented here is based on the premise that there are now better ways than net metering to encourage solar adoption that send the right signals to developers and consumers, drive technological innovation, and allow utilities to more easily manage the increase in intermittent generation. This paper presents policy concepts for two important distributed solar market segments in Maine: Customer-sited (systems installed for residential and small commercial/industrial customers); and Wholesale (systems installed on the utility side of the meter within the distribution system). An aggregation entity, or "Solar Standard Buyer" (SSB) would interface with the customer sited market segment. Under the existing net metering construct, this role is currently assumed by the Standard Offer Provider or a customer's competitive electricity provider. Centralizing procurement with the SSB would allow for a more efficient aggregation and sale of the different attributes solar energy can provide. The SSB would aggregate the energy, RECs, capacity value, and ancillary services potential and monetize these in the applicable markets. As stated previously, the underlying goal of the policy structure is to allow Maine ratepayers to capture the benefits of distributed solar energy while minimizing the costs and inequities experienced in other states. … While many details would need to be defined, it is our hope that all parties can agree on the general goal of maximizing benefits while mitigating costs, and that this common guiding principle can foster further dialogue on strategic and sustainable solar deployment in Maine." State of Maine Office of the Public Advocate and Strategen, "A Ratepayer Focused Strategy for Distributed Solar in Maine," 2016, pages 1, 6-7, 16.
http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf

[59] I have previously written about these conditions for successful markets. Susan Tierney, "ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In," October, 2008, pages 15-16.

[60] A recent white paper prepared by SolarCity, suggested that in jurisdictions where the utility has the role of distribution system owner and operator, it would be constructive to allow a "new utility sourcing model, which we call infrastructure-as-a-Service,' that allows utility shareholders to drive income, or a rate of return, from competitively sources third-party services." SolarCity Grid Engineering, "A Pathway to the Distributed Grid," February 2016, page 2.

[61] Con Edison Corporate Profile, http://investor.coned.com/phoenix.zhtml?c=61493&p=irol-homeprofile.

[62] Con Edison Newsroom electric system, http://www.coned.com/newsroom/energysystems_electric.asp.

[63] Con Edison's service territory in square miles comes from Con Edison Newsroom electric system, http://www.Con Edison.com/newsroom/energysystems_electric.asp. New York State's land area covers 47,214 miles. U.S. Geological Survey data, http://www.theus50.com/fastfacts/area.php.

[64] State population data for New York State: https://www.census.gov/newsroom/press-releases/2015/cb15-215.html.

[65] NYISO, "2015 Load & Capacity Data (Gold Book), Table I-2a: Baseline Forecast of Annual Energy & Coincident Peak Demand, combining the data for zones I and J.

[66] Con Edison provided this information on March 25, 2016, The figures for grid-interconnected DER reflect the MW of installed (nameplate) capacity tracked through Con Edison's distribution-system interconnection process, and includes solar PV (94.1 MW), wind (0.1 MW), fuel cell (7.8 MW), gas turbine (40.1 MW), internal combustion engine (102.9 MW), micro-turbines (9.8 MW), steam turbines (3 MW), and battery (0.9 MW),

[67] Con Edison provided this information on March 25, 2016. The figures reflect: 186 MW of net-peak-reduction due to energy efficiency; 260 MW of DR participating in the NYISO DR program, and another 45 MW of Con Edison DR (with the latter two DR program amounts reflecting enrolled capacity derated to expected performance levels.

[68] SCE, Our Service Territory, https://www.sce.com/wps/portal/home/about-us/who-we-are/leadership/our-service-territory/!ut/p/b1/hdBNDoIwEAXgs3gBZqAFZVnEQDVR-TFgNwYNVhSpASLXFxI2LsTZveR7izcgIAVRZe9CZm2hqqwcsrBO-sljPo-Q70LiIg-N2GZ0g3Sp9-DYA_xxDP_1ExDfxIupidwx5sRzOAltYxrEK3MauJSOwPZw5a93AwgIchLgNmKMIFojmFixBiFLde4_krgg9lO_NHLYzqozWUgQdX7N67zWbqppIe26TpNKyTLXLuoJr2eKBb-bj4TNPjgYPjk!/dl4/d5/L2dBISEvZ0FBIS9nQSEh/.

[69] California's land area covers 155,959 miles. U.S. Geological Survey, http://www.theus50.com/fastfacts/area.php.

[70] SCE Distribution Resources Plan, July 1, 2015, page 26, which provides detail for the basis on which SCE has estimated these amounts of DER.

[71] The California Energy Commission has forecast a 2016 coincident peak load of 23,537 MW for SCE's planning area (based on the 2014 mid-energy demand estimate). Table 10 of CEC, "California Energy Demand Updated Forecast, 2015-2025, February 2015, Table 10.

[72] AB 327 text: Section **769.** "(a) For purposes of this section, "distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. (b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan."

[73] SCE's DRP can be found accessed at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/BF42F886AA3F6EF088257E750069F7B7/$FILE/A.15-07-XXX_DRP%20Application-%20SCE%20Application%20and%20Distribution%20Resources%20Plan%20.pdf.

[74] See E3's website: https://ethree.com/public_projects/cpuc5.php.

[75] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[76] Finding of Fact #12, CPUC, Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking Docket 14-07-002. Finding of Law #25 found that "In order to ensure that the NEM successor tariff is consistent with Commission policy on distributed energy resources, makes use of relevant information about locational benefits and optimal DG resources, and is appropriately aligned with changes to retail rates for residential customers, the successor tariff adopted in this decision should be reviewed in 2019."

[77] CPUC, "Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scope Memo," Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources, Rulemaking 14-10-003 ("CPUC IDER Rulemaking Memo"), page 5.

[78] CPUC IDER Rulemaking Memo, page 3. This proceeding will address four issues (paraphrased from the original document on pages 6-7):

1. Development of a competitive solicitation framework targeting the reliability needs within particular areas: …including defining the services to be bought and sold within those areas, as well as development of rules and oversight requirements related to those solicitations.
2. Further development of technology-neutral valuation or cost-effectiveness methods and protocols, including incorporating location-specific considerations;
3. Leveraging the work being performed through the Distribution Resource Plans Demonstration Projects where practical for the purpose of advancing the development of a competitive solicitation framework for distributed energy resources."
4. Utility role, business models, and financial interests with respect to distributed energy resources deployment.

[79] See the REV website: https://www.ny.gov/programs/reforming-energy-vision-rev.

[80] Audrey Zibelman, Chair, NY PSC, "Reforming the Energy Vision," presentation to the New England Electric Restructuring Roundtable, June 27, 2014. Also, the New York State Energy Plan describes the REV regulatory docket:

> In April 2014, the PSC commenced the REV regulatory proceeding to reform New York State's electric industry and utility regulatory practices. The REV Regulatory Docket considers an overhaul of New York's utility regulations to give customers greater value from and choice over their energy use, facilitate the rapid expansion and integration of DERs into the State's energy system, and transition clean energy from the periphery to the core of investor-owned utilities' business models. By redesigning price signals, revising utility compensation structures, and opening up access to previously undisclosed data (bearing in mind privacy concerns), the REV Regulatory Docket aims to maximize utilization of all behind-the-meter resources such as demand management, energy efficiency, clean distributed generation, and storage to reduce the need for costly new infrastructure.
> Building upon the success of the State's recent regulatory reforms, REV will also aim to further the establishment of robust retail energy markets that recognize and account for the environmental and economic values of energy efficiency and load management. As a result, REV will increase opportunities for existing and new market participants to develop both central and distributed generation resources, which will create value for New York's consumers, more energy sector jobs, and a cleaner energy generation mix."

"Energy to Lead: 2015 New York State Energy Plan," pages 47-48.

[81] NY PSC, Case 15-E-0082, Proceeding on a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings, July 17, 2015, page 24.

[82] NY PSC, Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, January 21, 2016. The NY PSC has stated that the benefit/cost analysis

> will be applied to four categories of utility expenditures: investments in Distributed System Platform (DSP) capabilities; procurement of Distributed Energy Resources (DER) through competitive selection; procurement of DER through tariffs; and, energy efficiency programs. The BCA Framework enables the careful comparison of the value of the benefits obtained through a potential project or action against the costs incurred in effectuating that project or action, generally considered through the systematic quantification of the net present value of the project or action under consideration…..
>
> In the BCA Whitepaper, the proposed BCA Framework is premised upon a number of foundational principles. The BCA analysis should: 1) be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular; 2) avoid combining or conflating different benefits and

costs; 3) assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures); 4) address the full lifetime of the investment while reflecting sensitivities on key assumptions; and, 5) compare benefits and costs to traditional alternatives instead of valuing them in isolation. The BCA Framework will rest upon the selection of methodological approaches, which include the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM).

Those benefits and costs that should not or cannot be reflected in the Framework will be clearly delineated. The outcomes of the BCA analysis should allow for judgment and where appropriate a qualitative assessment of non-quantified benefits. The interests in sustaining a stable investment environment to support the DER market would be balanced with remaining flexible and adaptive so that the valuation process does not become outdated or inaccurate. Over time, developing more dynamic and granular methods will require a continuous process, rather than a single decision. Therefore, the matters addressed here are only the first initial step in forming a robust and long-lasting BCA Framework.

That Framework will stand within the broader scope of REV implementation. Under REV, utilities will file Distribution System Implementation Plans (DSIP) by June 30, 2016 that identify opportunities to avoid traditional utility distribution and investments by calling upon the DER marketplace.3 The BCA Whitepaper identifies means for evaluating DER alternatives as substitutions for traditional utility solutions, and against each other. Alongside cost avoidance and system efficiency benefits, the BCA Framework as proposed would reflect consideration of social values, also known as externalities, quantifiably when feasible and qualitatively when not. A full evaluation of alternatives over their expected lives, it is suggested, would be accomplished by stacking resources of different characteristics into a portfolio that results in meeting system needs in the aggregate.

Besides evaluation of electric system alternatives, the BCA Framework should support the developments of tariffs that place a value on DER. The evaluation of tariffs, however, differs from the evaluation of utility system alternatives, because tariffs are more dynamic measures of near term benefits and costs. Dynamic tariffs may be self-adjusting or embed other mechanisms to address the concern of variation over time. The tariffs can serve as an incentive mechanism to promote the development of a more competitive behind-the-meter market, including the installation of the DER facilities currently promoted through the device of net metering tariffs. Through these processes, the BCA Framework will work in coordination with the DSIPs, upon the identification of processes for assuring fair, open and value-based decision making.

When utilities present their DSIPs, each utility will identify its system needs, proposed projects for meeting those needs, potential capital budgets, particular needs that could be met through DER or other alternatives, and plans for soliciting those alternatives in the marketplace....(pages 1-3)

The Commission adopts SCT as the primary measure of cost effectiveness under the BCA Framework. The SCT recognizes the impacts of a DER or other measure on society as a whole, which is the proper valuation. New York's clean energy goals are set in recognition of the effects of pollutants and climate change on society as a whole, and only the SCT would both properly reflect those policies and create a framework for meeting those goals.

The UCT and RIM tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis. (page 12)

[83] NY PSC, Case 15-E-0407, Orange and Rockland Utilities, Inc. – Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation, October 16, 2015.

[84] NY PSC, Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources, Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference, December 23, 2015, Attachment A (Questions on the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology), pages 3-4.

[85] K. Anderson, M. Coddington, K. Burman, S. Hayter, B. Kroposki, and A. Watson, "Interconnecting PV on New York City's Secondary Network Distribution System," NREL, November 2009.

[86] Con Edison, "BQDM Quarterly Expenditures & Program Report," Q3-2015, page 22.

[87] See: EPRI, "The Integrated Grid: A Benefit-Cost Framework," 2014, and 'The Integrated Grid: Phase II: Development of a Benefit-Cost Framework," 2014. The latter report explains on page 3 that

EPRI launched its Integrated Grid initiative with a concept paper [1] and the goal of aligning power system stakeholders on key issues. With widespread adoption of distributed energy resources (DER), potentially fundamental changes in the grid will require careful assessment of the benefits, costs, and opportunities of different technological or policy pathways. Four main areas requiring global collaboration were identified: Interconnection rules and standards; Grid modernization; Strategies and tools for grid planning and operations; Enabling policy and regulation.
Work on the three-phase Integrated Grid initiative is intended to provide stakeholders with information and tools that are integral to these four areas. Phase I – Stakeholder alignment, including the production of a concept paper, supporting documents, and related knowledge transfer efforts. Phase II – Development of a benefit-cost framework, interconnection technical guidelines, and recommendations for grid operations and planning with DER. Phase III – Global demonstrations and modeling to provide comprehensive data that stakeholders will need for transitioning to an integrated grid.

[88] EPRI, "The Integrated Grid: A Benefit-Cost Framework," 2014, pages xvii-xviii.

[89] EPRI, "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources," 2014.

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Locational Value of Distributed Energy Resources

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Snuller Price, Energy and Environmental Economics, Inc.

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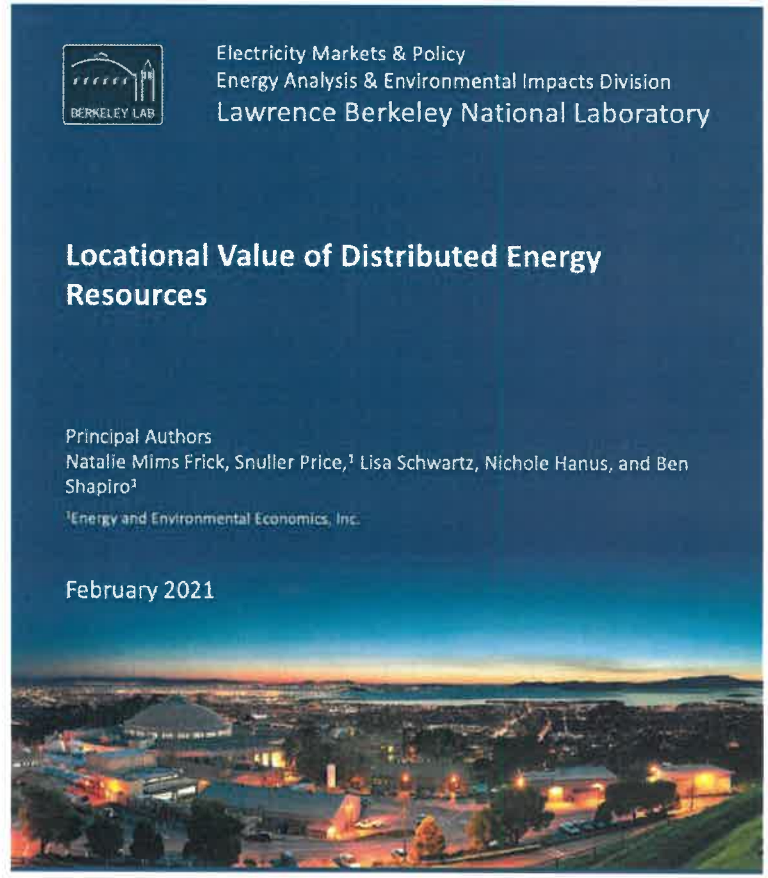
Today's speakers

- **Natalie Mims Frick** is an Energy Efficiency Program Manager in the Electricity Markets and Policy Department at Berkeley Lab. She manages projects on energy efficiency and other distributed energy resources (DERs), including technical assistance to states and research on DER policies and programs. Before joining the lab, Natalie was the principal at Mims Consulting, LLC, where she served as an expert witness in demand-side management regulatory proceedings across the country. She also was an Energy Efficiency Director at the Southern Alliance for Clean Energy and a Senior Consultant at Rocky Mountain Institute.
- **Snuller Price** leads E3's work on energy and climate policy, energy efficiency, demand response and other DERs, and renewable energy and emerging technologies. He has helped state and federal government agencies, utilities and technology companies support a clean energy transition for more than 25 years. His work in regulatory analysis focuses on evaluation of DER cost-effectiveness, and he has contributed to assessments of the largest and most sophisticated DER programs in the U.S., including in California and New York. He also built several tools to support utility distribution planning and assessment of DERs.
- **Lisa Schwartz** is a Deputy Leader of Berkeley Lab's Electricity Markets and Policy Department. She manages work spanning utility regulation, electricity system planning, energy efficiency and other DERs, and grid-interactive efficient buildings and leads training for states on integrated distribution system planning. Previously, she was Director of the Oregon Department of Energy. At the Oregon Public Utility Commission, she was staff lead on resource planning and procurement, demand response, and distributed and renewable energy resources. She also served as a senior associate at the Regulatory Assistance Project.

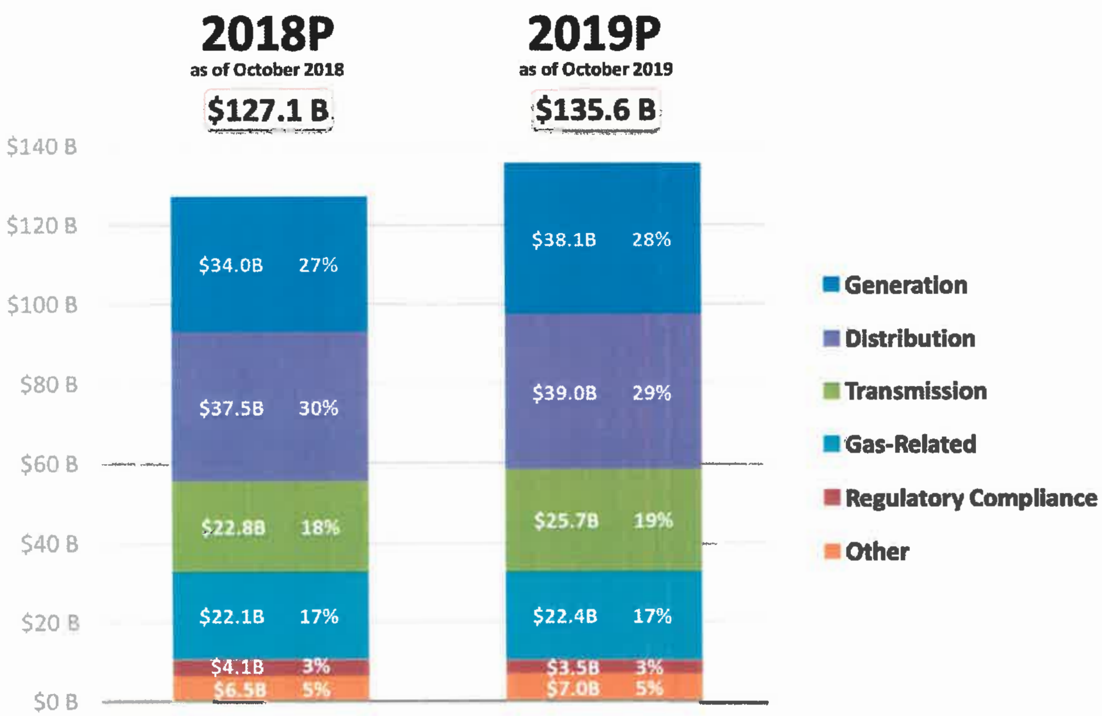
Summary

- As solar panels cover more rooftops, and buildings with load controls and storage provide more grid services, understanding the value of DERs is increasingly important. Yet few utilities and states consider their *value at specific points on the electric system* in planning, procurement, and design of DER programs and rates.
- DERs can provide significant utility system benefits by generating electricity or controlling or reducing electricity consumption, avoiding some types of electricity system costs.
- The potential value of a DER at a specific location on the grid depends on its capability and potential costs it can avoid at that location.
- Electricity markets, policies and regulations affect assessment of DER value. Several jurisdictions provide guidance to utilities for considering DERs as non-wires alternatives (NWAs) in transmission and distribution (T&D) planning.

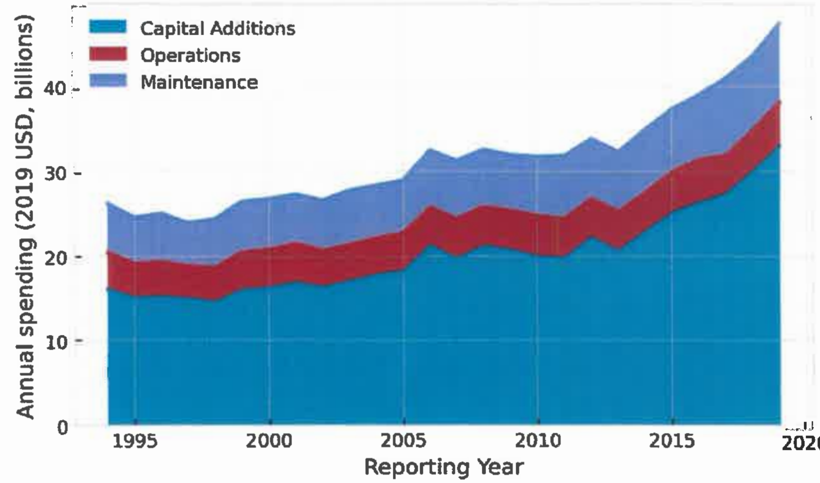


Report and these slides at https://emp.lbl.gov/publications/locational-value-distributed-energy

Distribution system investments are large and increasing.



Source: Edison Electric Institute



Source: Fowley and Duncan, UC Berkeley, based on FERC Form 1

For investor-owned utilities, distribution system investments account for the largest portion (29%) of capex: $39 billion in 2019.

EIA estimated that distribution system capital investments for major electric utilities of all types nearly doubled over the past decade.

Quantifying locational value of DERs informs distribution system planning as well as procurement, rates and programs.

Accurately valuing all potential distribution system solutions, including consideration of the locational value of DERs, is increasingly important for reliable, least cost electricity systems.

Locational Value Use Cases

Use Case	Objective	Capability	Challenges
NWAs Procurement	Enable market-based provision of DER services	Procure NWAs to defer T&D investment	Quantification of costs and benefits; risk management
Tariff Design	Provide price signals for DER locations	Link locational value analysis to tariff design	Efficient, transparent price mechanisms for benefits or costs
Program Design	Enhance system value of programs	Target program customer acquisition and/or incentives	Customer acquisition; risk management; coordination

Source: ICF 2018

DERs can provide grid services

DERs can provide grid services to support the generation and delivery of electricity from the utility to the consumer and provide value through avoided electricity system costs (including consumers who provide electricity to the grid)—the cost of acquiring the next least expensive alternative resource that provides comparable services.

Grid Service	Potential Value (Avoided Cost)
Generation Services	
Generation: Energy	Power plant fuel, operation, maintenance, and startup and shutdown costs
Generation: Capacity	Capital costs for new generating facilities and associated fixed operation and maintenance costs
Ancillary Services	
Contingency Reserves	Power plant fuel, operation & maintenance, and associated opportunity costs
Frequency Regulation	Power plant fuel, operation & maintenance
Ramping	Power plant fuel, operation, maintenance, and startup and shutdown costs
Delivery Services	
Non-wires alternatives	Capital costs for transmission and distribution equipment upgrades
Voltage Support	Capital costs for voltage control equipment (e.g., capacitor banks, transformers, smart inverters)

DER value across the power delivery supply chain comes from avoided costs

Power Delivery Impacts

DER Value Creation

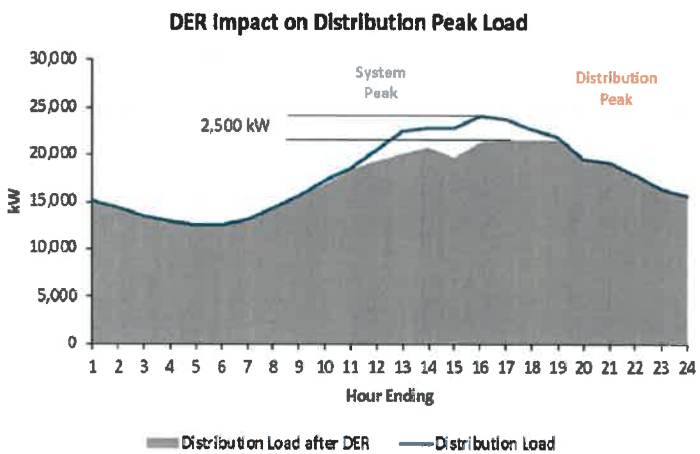
Value Category	Generation (System Values)	Transmission	Distribution (Locational Values)
Energy	Fuel combustion, Power purchase agreement costs	Transmission losses	Distribution losses
Capacity	New power plants & storage resources	New transmission facilities	New distribution facilities
Operations	Ancillary services	Ancillary services, Volt-var control	Voltage and var control
Environment	Air emissions, land use, water, waste	Land and right-of-way procurement	Land and right-of-way procurement

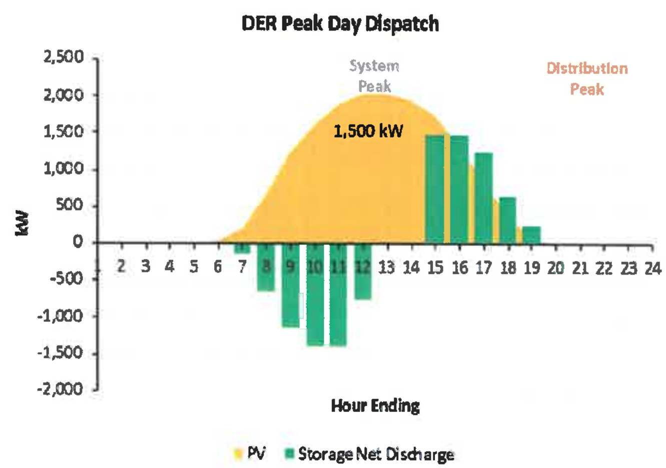
How can non-wires alternatives save energy costs?

- Defer or avoid infrastructure upgrades
- Implement solutions *incrementally,* offering a flexible approach to uncertainty in load growth and potentially avoiding large upfront costs for load that may not show up
- Typically, the utility issues a **competitive solicitation** for NWAs for specific distribution system needs and compares these bids to planned traditional grid investments (e.g., distribution substation transformer) to determine the lowest reasonable cost solution, including implementation and operational risk assessment.
- ***Locational net benefits analysis*** systematically analyzes costs and benefits of DERs to determine the *net* benefits DERs can provide for a given area of the distribution system.

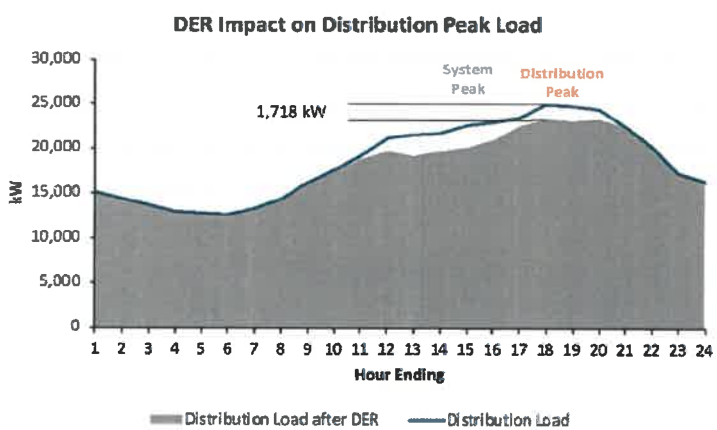
DERs that reduce demand during distribution system peak produce the most value

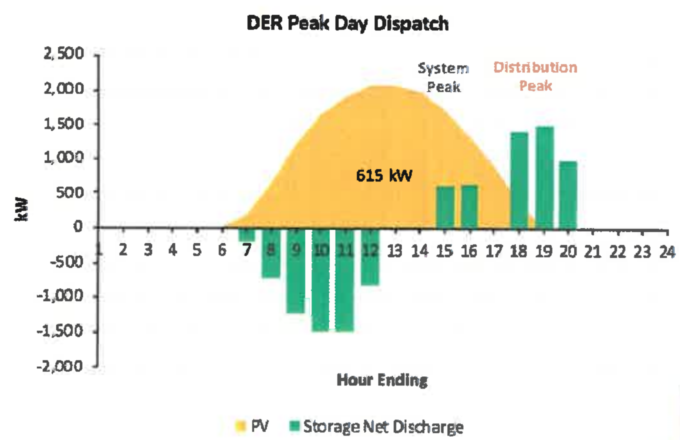
Peak load reductions from PV + storage when distribution and bulk power system peaks are coincident





Peak load reductions from PV + storage when bulk power system and distribution systems peaks are *not* coincident

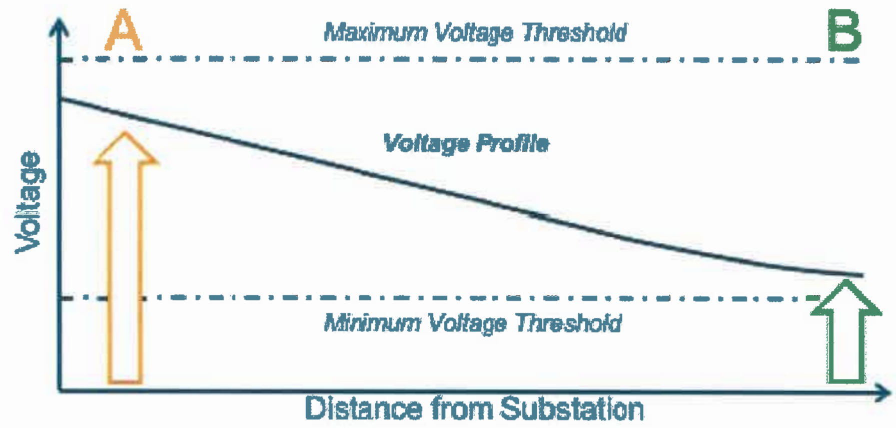




DERs located further from substations have a larger impact on voltage

The two significant constraints for feeder designs are voltage and current. Voltage must be kept within a range, while current must be lower than the rating of the equipment available.

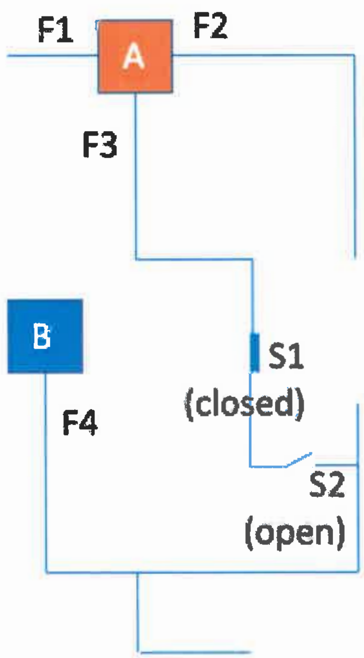
DERs located near the substation have a smaller impact on voltage because the amount of connected load is high relative to the size of the installed DER.



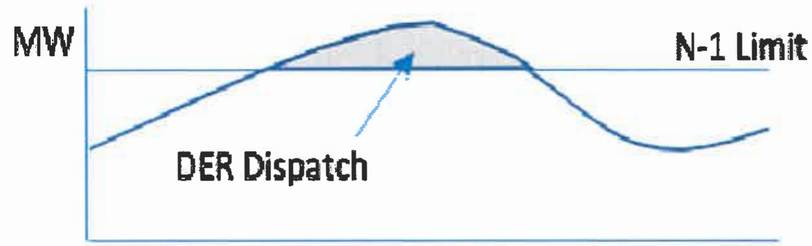
Interconnecting DER at Point A
- Voltage effects are more easily managed for DER near the substation.
- Current along the feeder is not affected, as the DER installation is not changing loads downstream.
- DER does not materially reduce feeder losses.

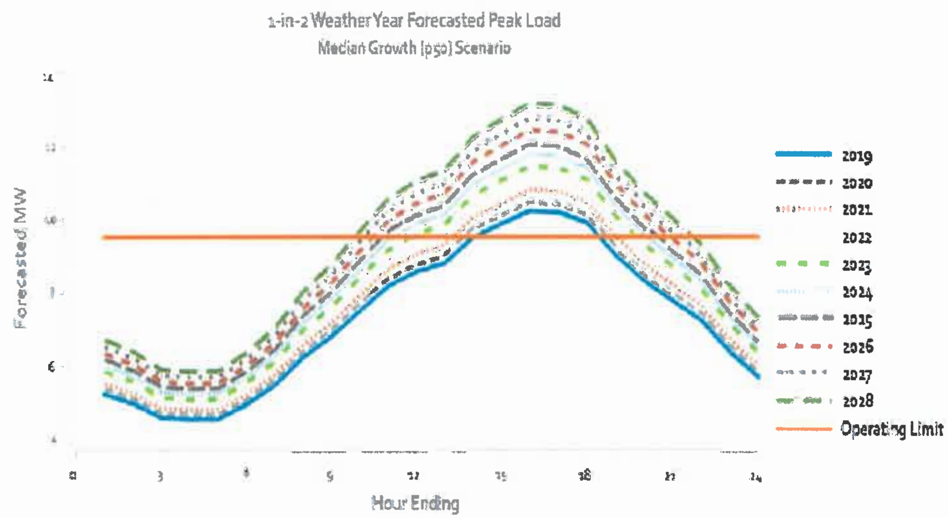
Interconnecting DER at Point B
- Voltage effects are more pronounced at the end of the feeder, which may be problematic if left unmanaged, or can present an opportunity to optimize DER deployment for voltage support.
- Current along the feeder is reduced as loads downstream are affected by the DER.
- DER has the opportunity to reduce feeder losses as it is reducing load further downstream.

Engineering considerations for estimating the locational value of DERs



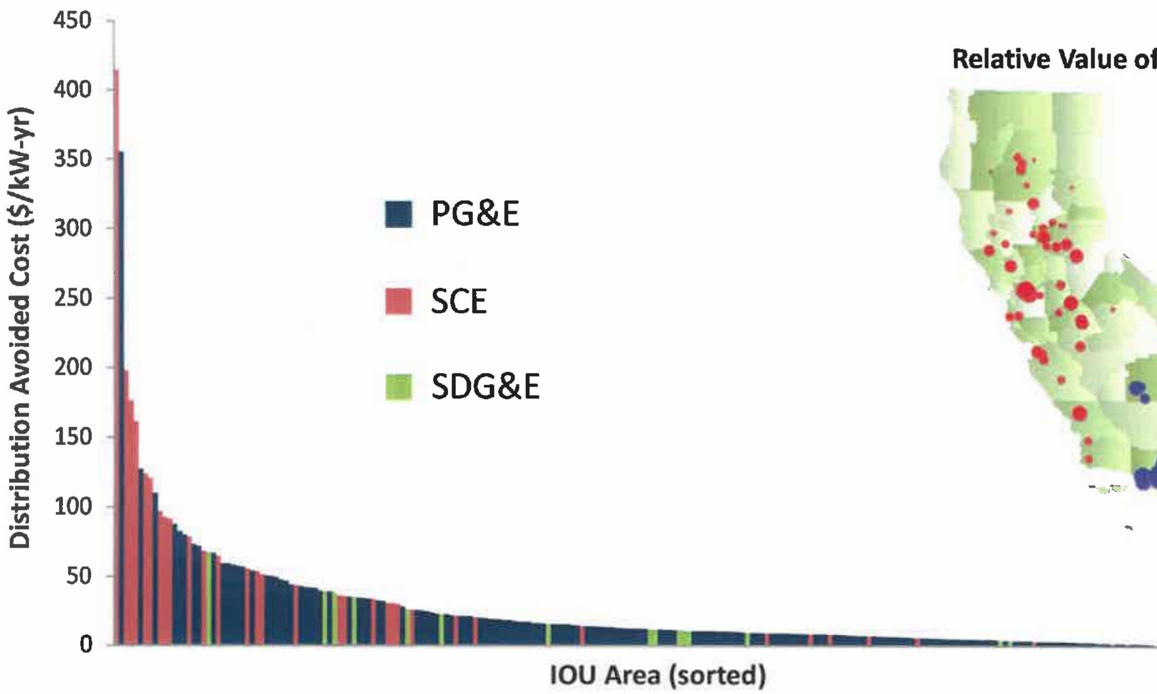
Legend
Substations A and B
F1, F2, F3, and F4 are feeders
S1 and S2 are switches

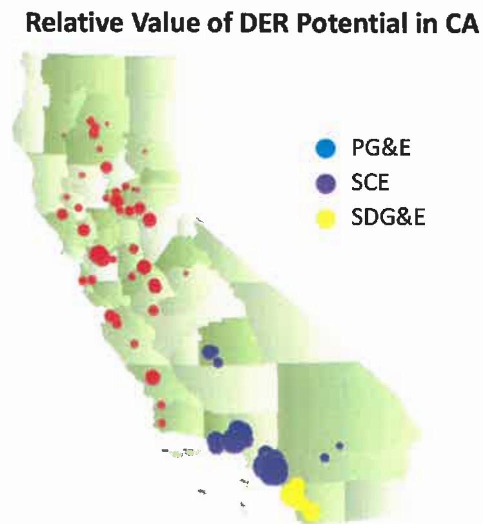




Right Place

- The graph shows the range of local distribution avoided costs by area from an E3 study for California using utility distribution planning information.
- There are high value locations across the state, but DERs must be targeted to capture the highest value.

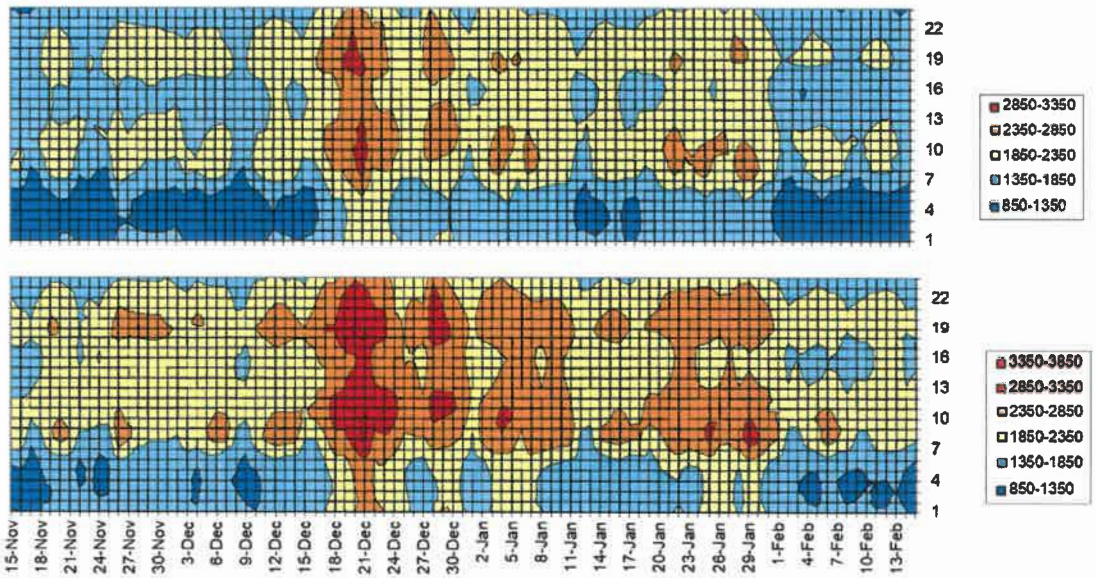




Right Time

- Within each of those areas, load reduction must be delivered at the right time.

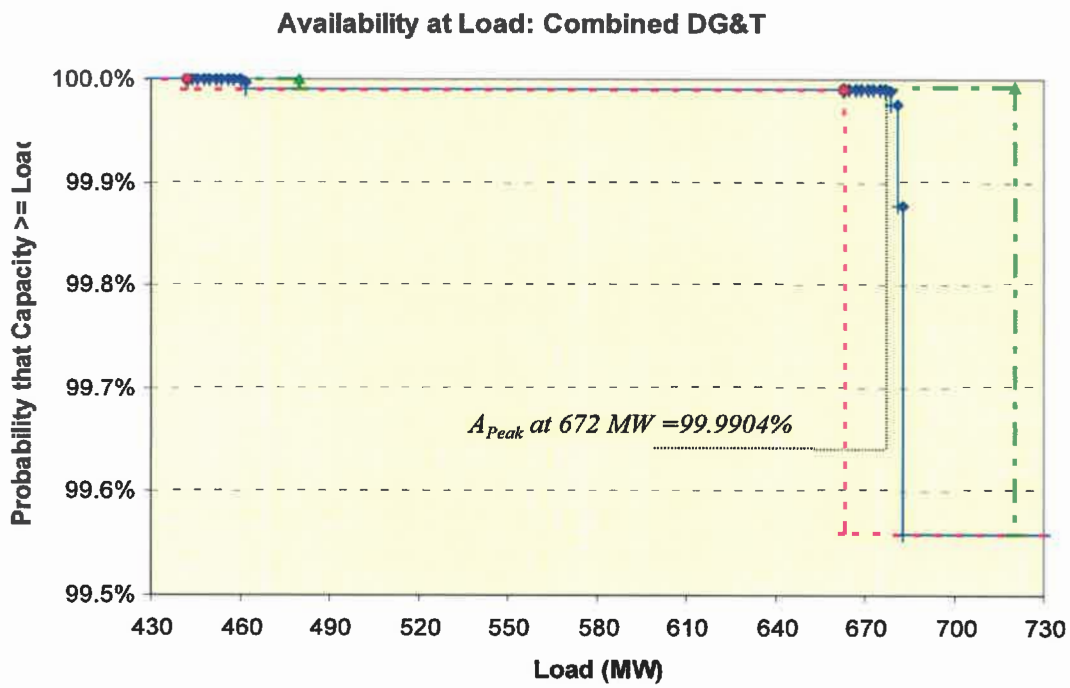
2004 and 2010 Load Projections for Region



Note: 2,850MVA is the emergency limit

Right Certainty

- Finally, DER must provide sufficiently reliable load reduction in order to provide sufficient certainty so that the distribution engineer who is responsible for the local area reliability is able to defer the investment.



Two approaches to assessing the locational value of DERs

	How Value Is Assessed	Typical Use Case
Area-specific Avoided Distribution Costs	Forward-looking value of local capacity deferral using the present worth method	Evaluation of hourly distribution value of specific DERs at specific locations
Distribution Marginal Cost of Service Studies	Long-run system average marginal distribution cost based on the historical relationship between distribution investment and peak load	Evaluation of costs and benefits of systemwide deployment of DERs

Present Worth (PW) Method: local distribution expansion planning

The essence of the PW method for area-specific avoided distribution costs is the value of deferring a local distribution expansion plan for a specific period of time. A one-year deferral value equals the difference between the present value of the distribution expansion plan and the present value of the same plan deferred by one year, adjusted for inflation and technological progress. The value of deferring capacity in year 1 for Δt years is:

$$PW\ Deferral\ Value = \sum_{t=1}^{n} \frac{K_t}{(1+r)^t}\left[1-\left(\frac{1+i}{1+r}\right)^{\Delta t}\right]$$

where:
n = finite planning horizon in years,
K_t = distribution investment in year t,
i = inflation rate net of technological progress,
r = a utility's cost of capital (discount rate),
Δt = deferral time = peak load reduction divided by annual load growth.

The PW deferral value can be divided by the associated incremental load change that produced the deferral to obtain a $/kW estimate of the marginal distribution capacity cost (MDCC):

$$\$/kW\ Marginal\ Cost = \frac{PW\ Deferral\ Value}{Deferral\ kW}$$

The MDCCs are allocated to hours in proportion to the likelihood that the hour will contain the peak load, using peak allocation factors (PCAFs):

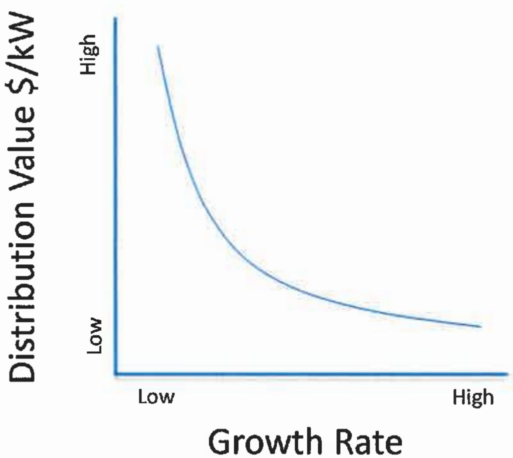
$$PCAF_h = \frac{(Load_h - Threshold)}{\sum_{h=1}^{8760}(Load_h - Threshold)}$$

where:
$Threshold$ = the peak period cut-off value

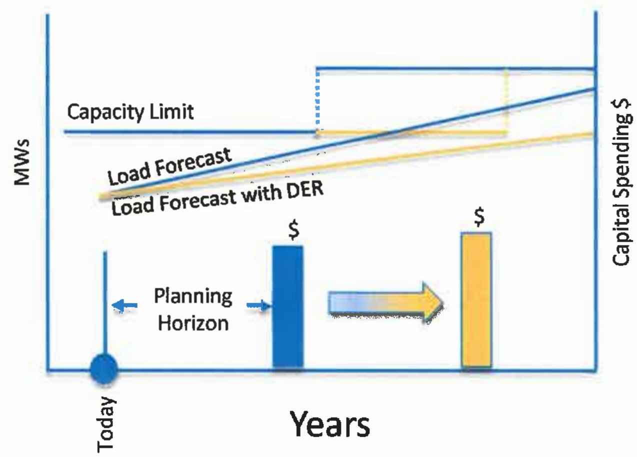
Implications of the Present Worth Method formula

Strategies

Slow Growth Areas Have Higher Marginal Value



Planning Horizon is Important to Capture Opportunities



Use system capacity value to deploy dispatchable DER system wide ("anchor tenant")

Use local value to increase ratepayer value and prioritize capital spending

Tools for calculating the locational value of DERs

	Utility/Developer	Publicly Available?
Single DER Solutions		
Brooklyn-Queens Demand Management Program Cost-Benefit Model	Consolidated Edison	Y
Avoided Cost Calculator	E3	Y
Long Island's Public Service Enterprise Group Value of Distributed Energy Resources Value Stack Calculator	PSEG	Y
New York Solar Value Stack Calculator	NYSERDA	Y
Portfolio of DER Solutions		
Locational Net Benefit Analysis Tool	E3	Y
Integrated Demand Side Management Model	E3	N
Solar + Storage Optimization Tool	E3	Y
Distributed Energy Resources-Customer Adoption Model (building/microgrid level)	Berkeley Lab	Y
Integrated Modeling Tool	Berkeley Lab	Y
REOpt: Renewable Energy Integration & Optimization	NREL	Y (REOpt Lite only)
Load Relief Needs and T&D Deferral Value Tool	Demand Side Analytics	N
DER Micro-potential and Non-Wires Optimization Tool	Demand Side Analytics	N
Battery Storage		
bSTORE	Brattle	N
RESTORE Model	E3	N
Storage Value Estimation Tool (StorageVET®)	EPRI	Y
Electricity Storage Valuation Tool	Navigant/TenneT	Y
QuESt	Sandia National Lab	Y

Market structure influences value of DERs

Organized Markets

- Value established by market
- Only values "products" traded in market:
  - Capacity
  - Energy
  - Reserves (spinning and balancing)
  - Volt/Var support
- Gaps/Challenges
  - Locational value of avoided/deferred T&D capacity not captured
  - Value of resilience
  - Value of increased hosting capacity
  - Recognition of "long-term" resource value in some markets

Vertically Integrated Utilities

- Value established through regulatory/planning processes (e.g., PURPA filings, IRPs)
- Value depends on scope of state "cost-effectiveness" test
- Gaps/Challenges
  - Not all states include all utility system benefits of demand flexibility or quantify them in a consistent manner (e.g., not all states use time-dependent valuation).
  - Methods to quantify and monetize the locational value of demand flexibility are "under construction."
  - Integrated analysis of the impacts of demand flexibility is complex, and thus rarely done.

Adapted from Tom Eckman and Lisa Schwartz, "Determining Utility System Value of Demand Flexibility," 2020

Two market issues for DERs

- Dual market participation
  - FERC Order 2222 enables participation of DERs in centrally organized markets through aggregation.
  - Dual market participation requires alignment of different markets to capture multiple, or stacked, value streams.
  - Utilities and RTOs/ISOs must specify which grid services can be provided simultaneously and which require a choice by the resource operator.
  - How markets will work together to assess value of local capacity resources and, in case of conflicting operational needs, to prioritize DER participation must be worked out.
- DERs in nested areas — a constrained distribution system that also is located in a constrained local transmission zone
  - Design of NWA procurement or utility program should encourage DER operations to relieve both constraints when possible.
  - But if timing of distribution and bulk power system peaks does not align, dispatching the DER to support one constraint may preclude operating the DER for the other constraint, requiring the establishment of dispatch priorities.

State policies affect the value of DERs.

- T&D value streams depend on the timing of DER savings or generation and grid location.
- Policies, regulations and market rules also affect assessment of DER locational value.

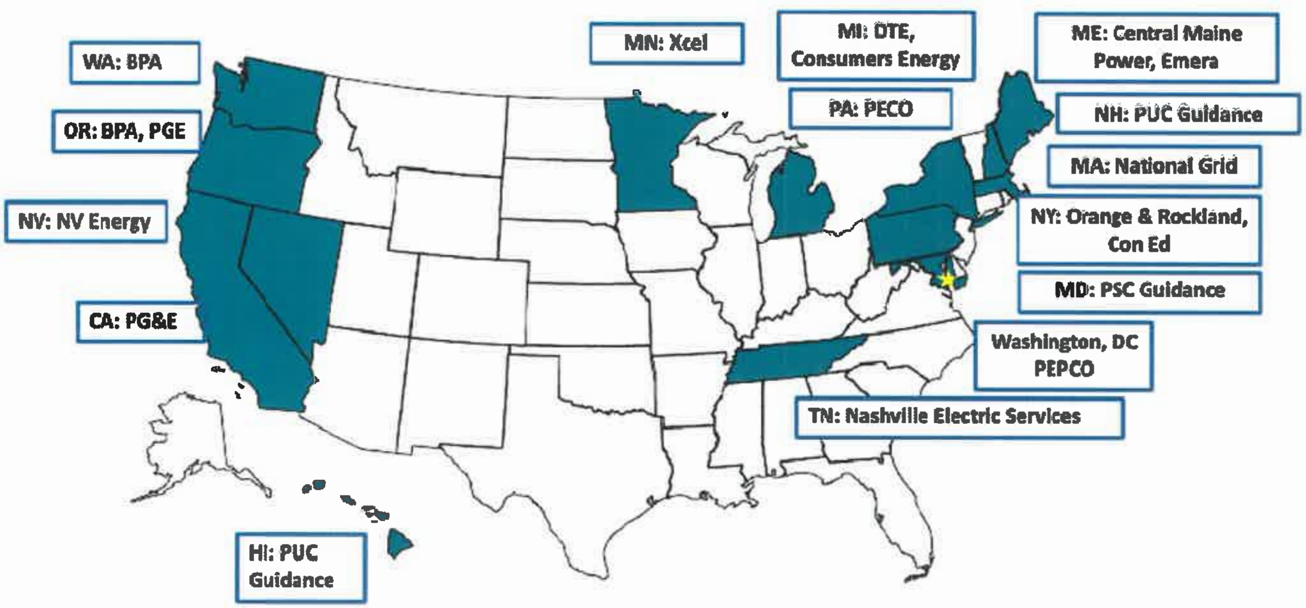
Value Category	Value Stream	State																					
		AZ	AK	CA	CO	HI	ME	MD	MA	MI	MN	MS	MT	NC	NJ	NY	NV	PA	SC	TN	TX	UT	VT
Generation	Avoided Energy																						
	Avoided Fuel Hedge																						
	Avoided Capacity & Reserves																						
	Avoided Ancillary Services																						
	Avoided Renewable Procurement																						
	Market Price Reduction																						
Transmission	Avoided or Deferred Transmission Investment																						
	Avoided Transmission Losses																						
	Avoided Transmission O&M																						
Distribution	Avoided or Deferred Distribution Investment																						
	Avoided Distribution Losses																						
	Avoided Distribution O&M																						
	Avoided or Net Avoided Reliability Costs																						
	Aviođed or Net Avoided Resiliency Costs																						
Environmental/Society	Monetized Environmental/Health																						
	Social Environmental																						
	Security Enhancement/Risk																						
	Societal (Economy/Jobs)																						

DER value streams identified by states, utilities, consultancies, and stakeholders

Source: Adapted by E3 from Shenot et al. 2019 and DOE 2018

Several states require utilities to consider non-wires alternatives.

- Jurisdictions that require consideration of NWAs include CA, CO, DE, DC, HI, ME, MI, MN, NV, NH, NY, RI.
- Several additional states have related proceedings, pilots or studies underway.



Case studies featured in new Berkeley Lab report, *Locational Value of Distributed Energy Resources*

Non-wires alternatives in California

- AB 327 (2013) requires electric utilities to submit distribution resources plans (DRPs) to "identify optimal locations for the deployment of distributed resources." The PUC's order on DRPs (2014) established guidance for utilities.
- The PUC approved a Distribution Investment Deferral Framework (DIDF, 2018) to identify and capture opportunities for DERs to cost-effectively defer or avoid utility investments planned to mitigate forecasted distribution system deficiencies.
  - Includes annual Grid Needs Assessments and Distribution Deferral Opportunity Reports that identify distribution upgrades that could be deferred with DERs
  - The DIDF process was modified in 2020 to require data alignment among IOUs, add data requirements, expand project requirements and modify deferral prioritization metrics.
- 2021 DIDF Request for Offers for PG&E and SCE were released in January.
- At its February 11th public meeting, the PUC adopted staff's proposal to: "1. Streamline and scale up DER deferral procurement, 2. Develop pilots to test the deferral tariff proposals and their elements, 3. Clarify incrementality policy for DERs sourced for deferral." Two new frameworks will encourage additional NWA projects:
  - Standard offer contract – To decrease transactional cost and risk compared to the current request for offers process (for large projects and aggregators, pilot launch August 15, 2021)
  - Clean Energy Customer Incentive – To enable dispatch by aggregators to address grid needs identified in DIDF process (for small projects, pilot launch January 15, 2022)

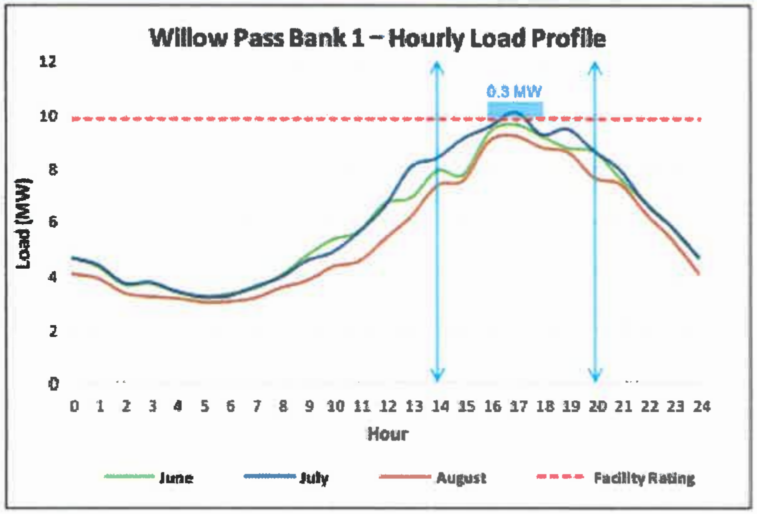
PG&E's 2021 DIDF identified more than 19 MW of grid needs

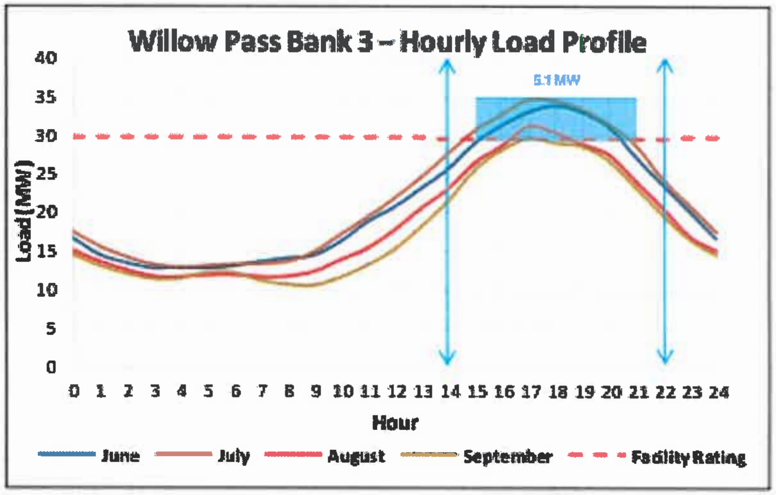
Candidate Deferral	GNA Facility Name	In-Service Date
WILLOW PASS BANK 1	WILLOW PASS BANK 1	2023
	WILLOW PASS BANK 3	2023
SAN MIGUEL BANK 2	SAN MIGUEL BANK 1	2023
	SAN MIGUEL 1104	2023
	PASO ROBLES 1107	2023
CALISTOGA BANK 1	CALISTOGA BANK 1	2023
	CALISTOGA 1102	2023
RIPON 1705	VIERRA 1707	2024
ZAMORA BANK 1	ZAMORA BANK 1	2023
GREENBRAE BANK 2*	GREENBRAE BANK 2	2023
BLACKWELL BANK 1 *	BLACKWELL BANK 1	2023

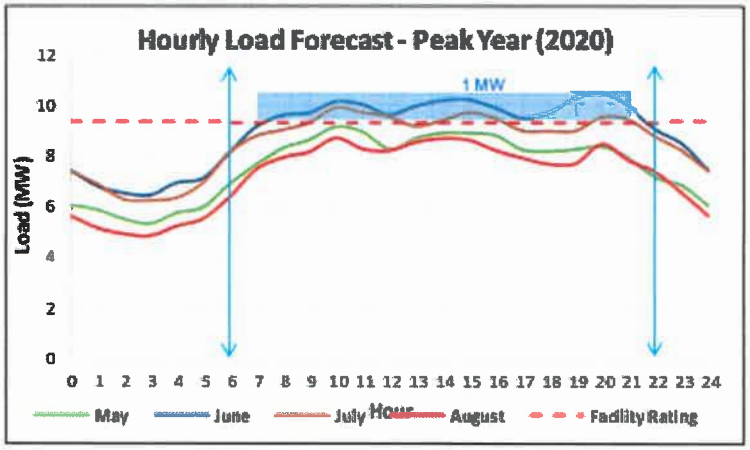
* CUSTOMER CONFIDENTIAL due to their peak loads violating the 15-15 customer privacy rule

Source: PG&E presentation on 2021 RFO for more than 19.6 MW support of local distribution capacity relief in seven areas in central California

PG&E's 2021 DIDF identified many different grid size and duration needs.

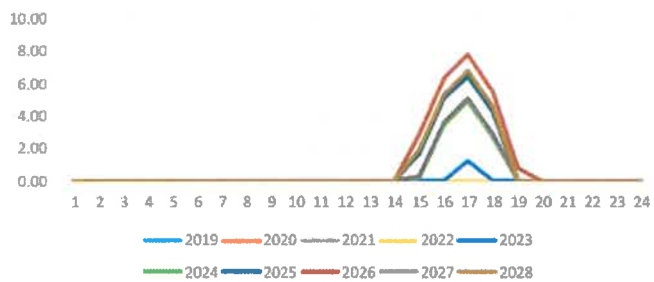




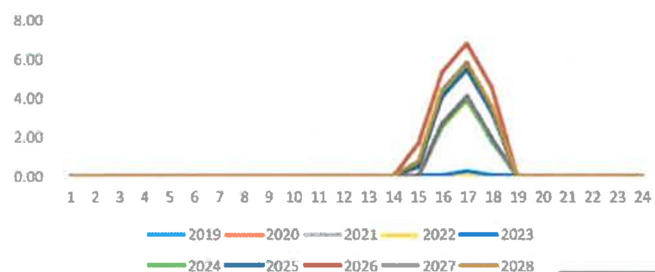


Southern California Edison is implementing two NWA projects.

Elizabeth Lake Project #1 Requirements



Elizabeth Lake Project #2 Requirements

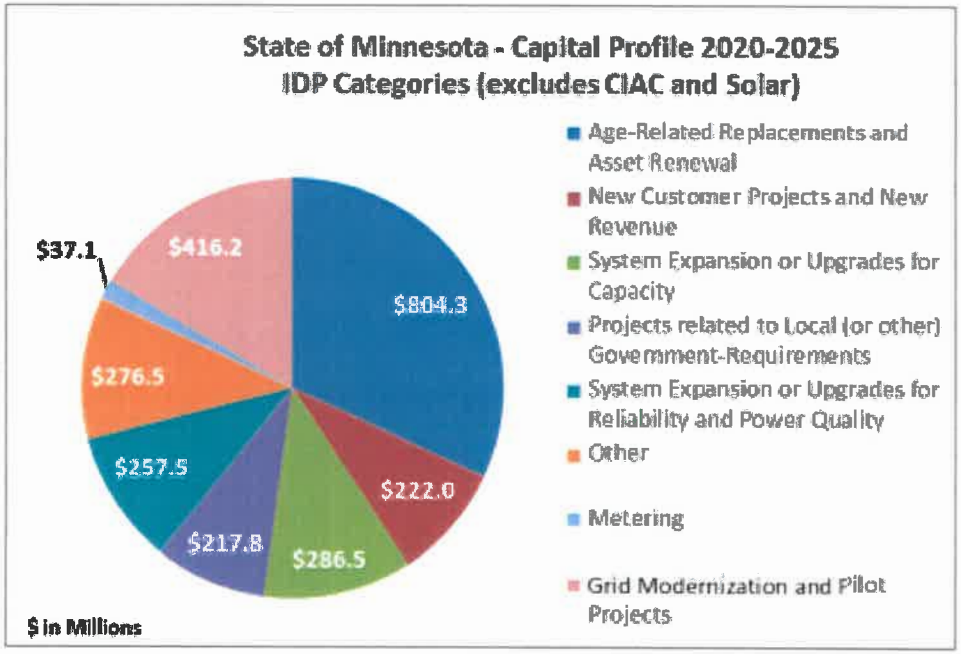


Seller	Deferral Projects	Interconnection (Circuit and/or Substation)	Technology Type	Size (MW)[2]	Initial Delivery Date	Term of Agreement (Years)
Homestead Energy Storage, LLC	Elizabeth Lake #1 and Elizabeth Lake #2	Elizabeth Lake 66/16 kV Substation	ES (Lithium Ion)	14	3/1/2023	10

Source SCE

Non-wires solutions in Minnesota

- Minn. Stat. §216B.2425 requires utilities to submit biennial T&D plans to the PUC.
- PUC established Integrated Distribution Planning requirements for Xcel Energy in Docket No. 18-251 and for smaller regulated utilities including:
  - For projects >$2M, analyze how non-wires solutions compare with traditional grid solutions in terms of viability, price and long-term value.
  - Specify distribution system project types (e.g., load relief or reliability) as well as timelines, cost thresholds and screening process for NWAs.
- Xcel Energy filed its 2020 Integrated Grid Planning report in October in Docket M-19-666, including analysis of NWAs.



Xcel Energy 2020 Integrated Distribution Plan NWA analysis results (MN)

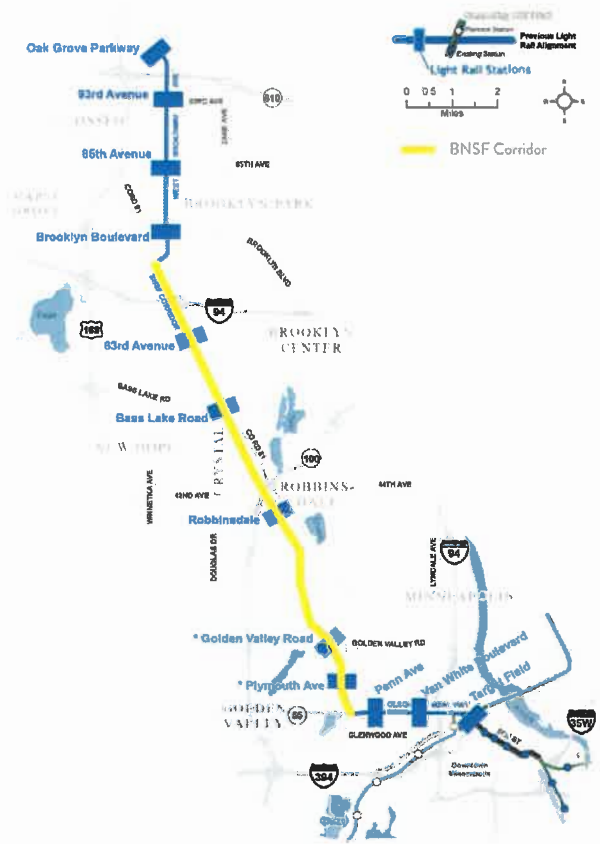
Project Name	Project Peak Demand (MW)	Project Energy Demand (MWh)	DR (MWh)	Existing Solar (MW)	Increm. Solar (MW)	Battery (MWh)	NWA Cost ($M)	Trad Cost ($M)
Kohlman Lake	10.28	40.2	0	0.90	0	39.4	15.8	4.5
Birch	17.9	57.5	0	12.8	0	45.2	18.1	7.1
Viking	9.2	55.1	2.26	0.3	0.18	54.7	22.2	4.1
Goose Lake	23.2	116.9	0	12.8	0	108.9	46.8	5.3
Burnside	12.8	111.5	0	23.7	16.3	66.9	59.4	2.7
Stockyards	13.4	77.9	0	0	0	77.9	68.1	4.0
Orono	10.3	186.6	0	0.3	0	186.6	76.1	4.1
Veseli	3.7	32.0	0	0.9	32.0	32.0	76.8	2.8
Cannon Falls	5.6	248.7	0	0	0	220.0	88.0	2.0
First Lake	15.1	259.0	0	11.1	0	227.5	91.0	3.2
West Coon Rapids	28.1	269.2	0	0	0	269.2	94.7	2.2
Faribault	31.6	415.8	0	3.0	2.5	401.1	165.4	2.0

Source: Xcel

Piloting NWAs in central Minnesota

- Focused on existing energy efficiency (EE) and demand response (DR) programs
- Partnership between Xcel Energy and Center for Energy and the Environment
- Targeted outreach in cities of Sartell and Sauk Rapids using community-based marketing strategies to increase program participation — e.g., for residential:
  - Community ambassador initiative
  - Coordination with city on promotions
  - Direct mail
  - Email campaign
  - Event tabling
  - Manufactured home outreach
  - Social media
- Sought to defer or avoid a new transformer and feeder reconfiguration
- Pilot achieved its goals for both EE and DR to meet the stated project needs
- Completed in summer 2020

Xcel Energy's proposed Minneapolis NWA



Source: Metropolitan Council

- Xcel included a preliminary proposal for a NWA that would provide resilience in their Relief and Recovery proposal.
- Xcel is considering a NWA along the METRO Blue Line Extension (Bottineau) light rail corridor using variety of NWA technologies in the ~2022-2024 timeframe.
- Hennepin County and the Metropolitan Council are exploring opportunities to advance the line extension without using BNSF Railway right of way.
- Xcel may identify a NWA pilot or demonstration elsewhere in Minneapolis.

Locational value in New York

- New York Public Service Commission has required utilities to evaluate DERs as an alternative to T&D capital projects since industry restructuring in the late 1990s.
- The 2014 Reforming Energy Vision (REV) proceedings were organized in two tracks: (1) REV Track One focused on the adoption of the Distributed System Implementation Plans and (2) REV Track Two focused on a transition away from net-energy metering via the Value of Distributed Energy Resources (VDER) mechanism.
- VDER uses marginal cost of service studies to define both a non-location-specific "Demand Reduction Value" and a locational system relief value that is added to the demand reduction value in utility-identified locally constrained areas.
- Objectives: New York aims for greater transparency for how utilities operate the grid, plan for system needs and compensate DERs. The location-based system is aligned with using markets and energy supply prices to encourage investment in and appropriately compensate DERs.

Track 1: Distribution System Implementation Plans

JOINT UTILITIES OF NEW YORK

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Overview of Currently Accessible System Data

- DISTRIBUTED SYSTEM IMPLEMENTATION PLANS
- CAPITAL INVESTMENT PLANS
- PLANNED RESILIENCY / RELIABILITY PROJECTS
- RELIABILITY STATISTICS
- HOSTING CAPACITY
- BENEFICIAL LOCATIONS
- LOAD FORECASTS
- HISTORICAL LOAD DATA
- NWA OPPORTUNITIES
- QUEUED DG
- INSTALLED DG
- SIR PRE APPLICATION INFORMATION

Distributed System Implementation Plans

Most recently, each utility filed an updated Distributed System Implementation Plan (DSIP) on July 31, 2018, which can be accessed in PDF format via the links below. Previously, each utility submitted its Initial DSIP on June 30, 2016 under the REV Proceeding, and the Joint Utilities filed a **Supplemental DSIP** on November 1, 2016.

Central Hudson Gas and Electric's 2018 DSIP: **Main Document | Appendices**

Consolidated Edison's 2018 DSIP: **Complete Document**

National Grid's 2018 DSIP: **Complete Document**

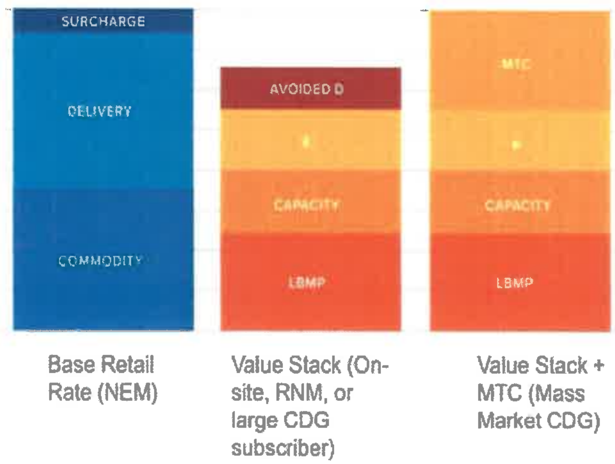
NYSEG and RG&E's 2018 DSIP: **Main Document | Appendix A: Guidance Requirements**

O&R's 2018 DSIP: **Complete Document**

Joint Utilities of New York - DSIPs and Publicly Accessible System Data

Track 2: New York Value Stack (VDER)

- Hourly Value Stack consists of:
  - Energy
  - System Capacity
  - Environmental Benefits
  - Market Transition Credit OR Avoided Distribution Value (based on Marginal Cost of Service studies)
- Certain projects also are eligible for Locational System Relief Value (LSRV)
  - LSRV credit is available to projects that are located in areas of the grid that are in need of peak load reduction for local capacity (e.g., congested sub-transmission and distribution areas)
  - Each utility provides maps of LSRV zones and MW limits of needed DG capacity
  - Compensation is tied to the utility's top 10 hours*
  - Zones, limits and credits are posted monthly on the VDER website



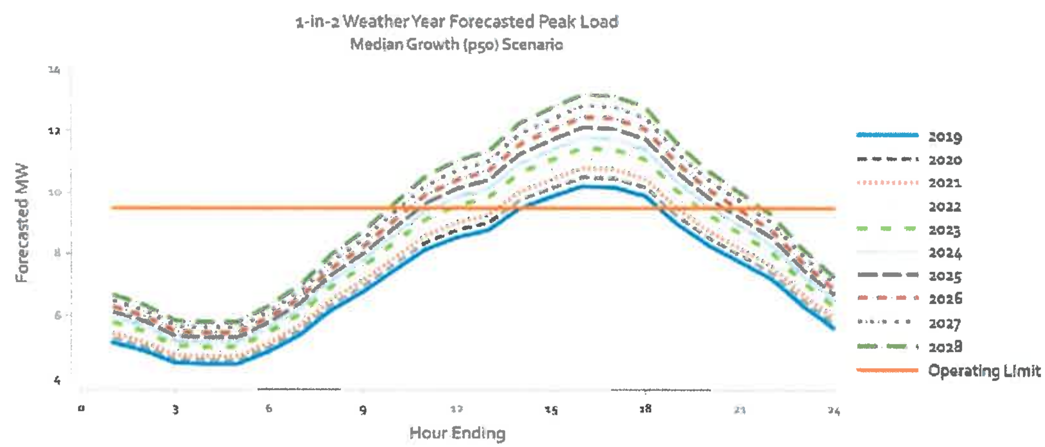
- Avoided D – avoided demand
- E – environmental benefit
- Capacity – ICAP
- LBMP – energy commodity
- MTC – market transition credit for CDG (Community Distributed Generation)

Example of Manhattan and Brooklyn LSRV Eligible Areas

* Note VDER has some changes since publication – see website

What we've learned so far.

- Methods were developed in the 1990s to value DERs for deferring or avoiding distribution capacity, when utilities began to test targeting and deploying DERs as NWAs and conducted evaluations. Utilities have continued to refine these approaches. (See utility case studies in our report.)
- Lessons learned
  - ***Identify value.*** The highest value opportunities are where low load growth is driving the utility toward a large capital investment, producing significant value per kilowatt of peak load relief. (Conversely, low load growth means lower utility sales to cover the cost of utility capital investments.) Lower value opportunities occur where DERs are competing with traditional distribution solutions that have greater economies of scale, particularly to serve high growth areas with significant capacity needs.
  - ***Plan well ahead.*** Sufficient time is required to deploy NWAs, make sure they're online before the constraint occurs, and verify reliable operation at the time needed — e.g., see New York Joint Utilities' suitability criteria:
    - 18-24 mos. for projects $300k* to $1M
    - 36-60 mos. for projects over ≥ $1M

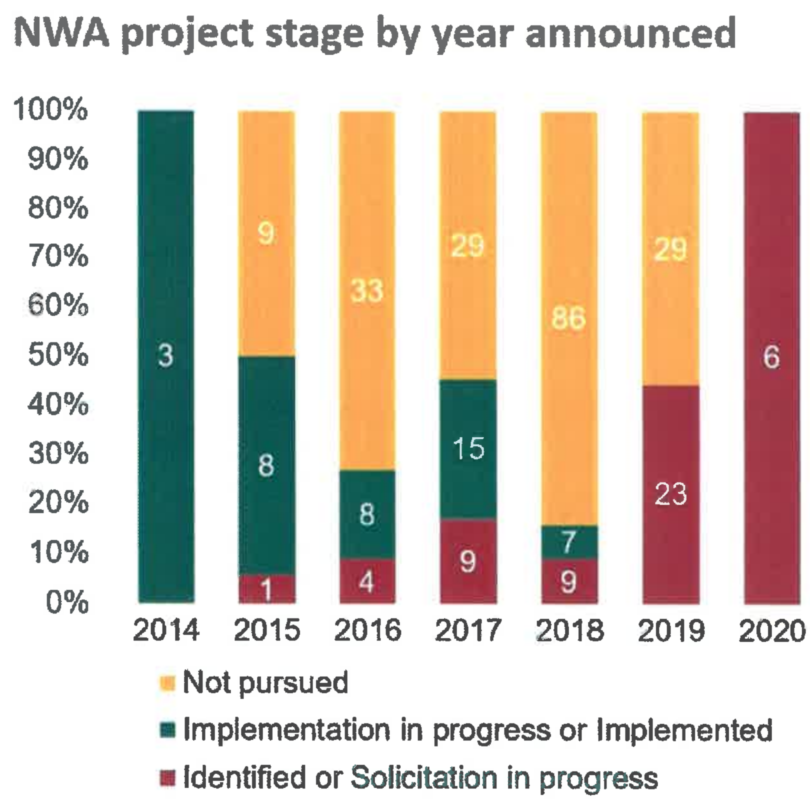


Graphic courtesy of Demand Side Analytics

*Transaction costs may be too high for projects smaller than this threshold. DER aggregation can solve that problem.

Procurements: NWAs are hot, but implementation is slow.

- ~850 MW of NWAs identified or implemented in the US
  - Projects only move forward 40% of the time and the number of identified opportunities that are implemented is shrinking.
  - Front-of-the-meter batteries are the most commonly implemented NWA.
  - Cost and reliability are key reasons for projects not going forward.
  - Broad disclosure of NWA opportunities both informs the public and also dilutes the share of NWA projects implemented.*
- In addition to analyzing DERs as alternatives to specific projects, utilities can conduct *systematic* studies of DER locational value to:
  - Better understand where to target DERs
  - Calibrate incentive levels
  - Reduce load growth for specific areas of the distribution system
  - Reduce the need for traditional distribution system upgrades.
- These studies can become a routine and transparent part of the utility's distribution planning process. Information also can be used for DER programs and rate designs.



Source: Wood Mackenzie Grid Edge service, Wood Mackenzie Data Hub

*Source: Debbie Lew, prepared for Berkeley Lab, based on data from Wood MacKenzie in GTM, "US non-wires alternatives H1 2020: Battery storage seizes top spot as utilities' preferred non-wires resource," (2020)

Resources

N. Mims Frick, S. Price, L. Schwartz, L. Hanus, and B. Shapiro. 2021. *Locational Value of Distributed Energy Resources*

N. Frick, T. Eckman, G. Leventis, and A. Sanstad. 2021. *Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets*

T. Eckman, L. Schwartz, and G. Leventis. 2020. *Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings*

T. Woolf, B. Havumaki, D. Bhandari, M. Whited, and L. Schwartz. 2021. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*

Berkeley Lab's research on time- and locational-sensitive value of DERs

U.S. Department of Energy's (DOE) Modern Distribution Grid guides

Distribution planning trainings: Midwest region (Oct. 2020), Western region (Feb./March 2021)

ICF. 2018. *Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*

A. Cooke, J. Homer, and L. Schwartz. 2018. *Distribution System Planning – State Examples by Topic*

J. Homer, A. Cooke, L. Schwartz, G. Leventis, F. Flores-Espino, and M. Coddington. 2017. *State Engagement in Electric Distribution Planning*

Berkeley Lab's Future Electric Utility Regulation reports

Berkeley Lab and NREL's End Use Load Profiles for the U.S. Building Stock project

BERKELEY LAB
LAWRENCE BERKELEY NATIONAL LABORATORY

U.S. DEPARTMENT OF ENERGY

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Using solar and storage to meet 100% of the electricity requirements of a distribution circuit

A case study for LG&E Highland 1103 circuit

LG&E
a PPL company

December 2018

Summary

This study evaluates the solar generation and energy storage requirements and associated economics of serving the electricity requirements of the LG&E Highland 1103 distribution circuit with local resources on a standalone basis, without connection to the power grid. This circuit has approximately 1,600 residential customers and 240 commercial customers that use approximately 20,500 MWh annually with a summer peak hourly demand of 8.9 MW. While the electricity consumption on the Highland 1103 circuit accounts for less than 0.4% of Jefferson County's total electricity consumption, its size and load characteristics are typical of many of LG&E's circuits and includes a customer mix that uses natural gas in their homes and businesses.

After evaluating a wide range of alternatives, this study shows that:

- While the technical challenges of using just local solar generation and energy storage to reliably serve the real-time electricity needs of customers on this circuit can likely be met, doing so would require a large geographic space (almost as large as the circuit footprint) that would result in land being used for solar panels and battery storage on a scale that would likely not be acceptable to the local community.

- Despite assuming customers would continue to use natural gas for space and water heating, the quantity of solar generation capacity required to be built would need to be about eight times greater than the summer hourly peak to generate enough energy to charge the batteries to reliably serve nighttime load and address extended periods of dense clouds and short days that are common during winters in Louisville.

- The cost of electricity would likely be two to five times higher over the 30-year study period as compared to continuing to take electricity from the LG&E system.

This study is an attempt to quantify, at a high-level, some of the technological and economic challenges associated with serving a typical distribution circuit with 100% locally generated renewable energy. In addition to the findings in this study, a number of questions, issues, and challenges were identified that were not addressed but were captured and documented for future consideration and included as part of this report.

Background

There is growing national interest in using renewable generation technologies to displace fossil-fuel generation in order to reduce CO_2 emissions.[1,2] Many advocates claim this can technically and economically be accomplished using existing renewable technologies in combination with current developments in storage technology.[3] Furthermore, some are interested in accomplishing this transition to 100% renewable generation via the use of microgrids based solely on distributed solar generation and battery storage.[4] This focus on local generation and storage development is often premised on the idea of creating local jobs and eliminating the need for central station power generation and its associated transmission grid.[5,6]

To understand and identify some of the challenges and issues that would need to be addressed in pursuing a local 100% solar/storage solution, this study used actual 2017 load and solar irradiance data for a representative LG&E distribution circuit to develop a range of possible technology and cost cases and compared the results to a range of costs of continuing with traditional utility grid service. The circuit that was selected is Highland 1103, which is located in the heart of Louisville. Figure 1 shows the geographic location (red rectangle) and electrical lines associated with this circuit.

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[1] Bloomberg New Energy Outlook 2018 — https://www.bnef.com/core/new-energy-outlook

[2] Benefits of Renewable Energy Use, Union of Concerned Scientists — https://www.ucsusa.org/clean-energy/renewable-energy/public-benefits-of-renewable-power

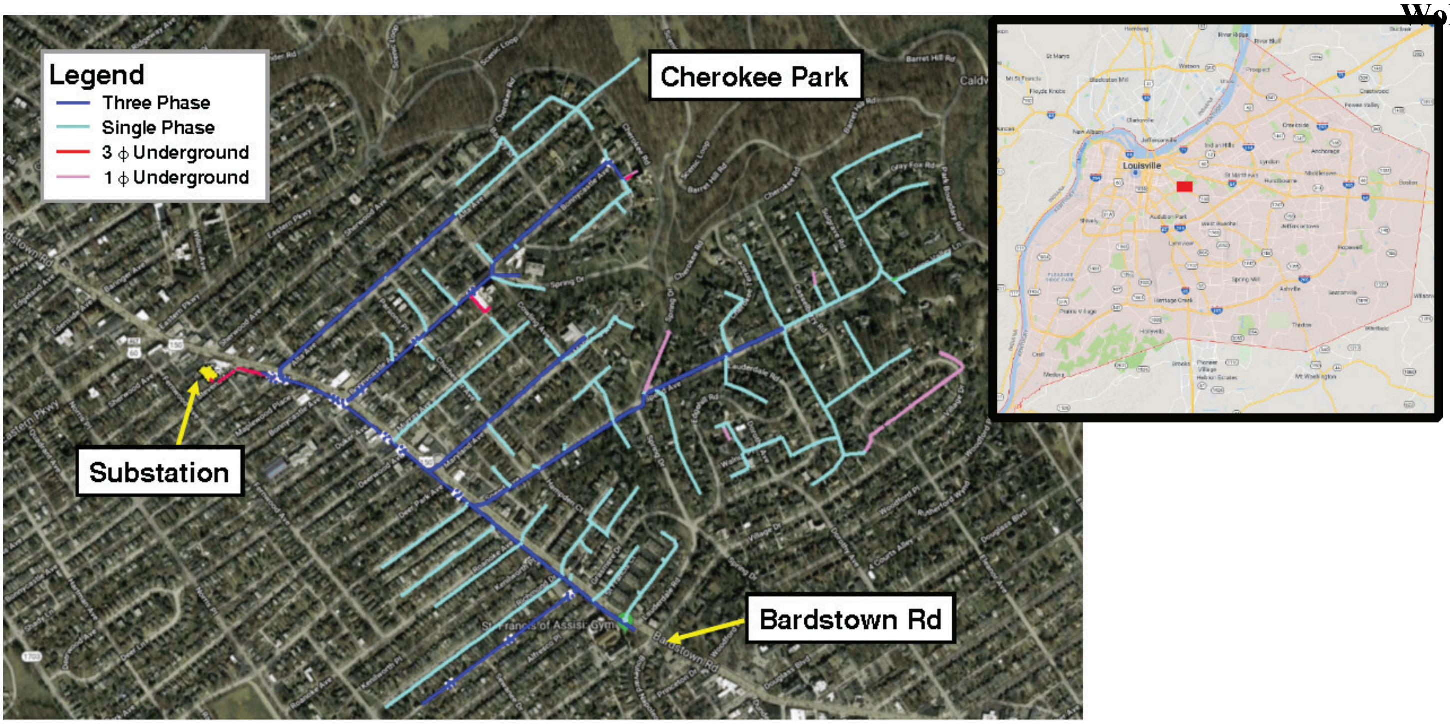
[3] How Energy Storage Can Pave the Way for Renewable Energy Adoption — http://climate.org/how-energy-storage-can-pave-the-way-for-renewable-energy-adoption/

[4] https://www.renewableenergyworld.com/articles/2017/08/100-percent-renewable-powered-microgrid-in-illinois-islands-from-the-grid-for-24-hours.html

[5] A Resolution for 100% Clean Energy for Metro Louisville Operations by 2030 and Community-wide by 2035.

[6] Distributed Generation of Electricity and its Environmental Impacts — https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts

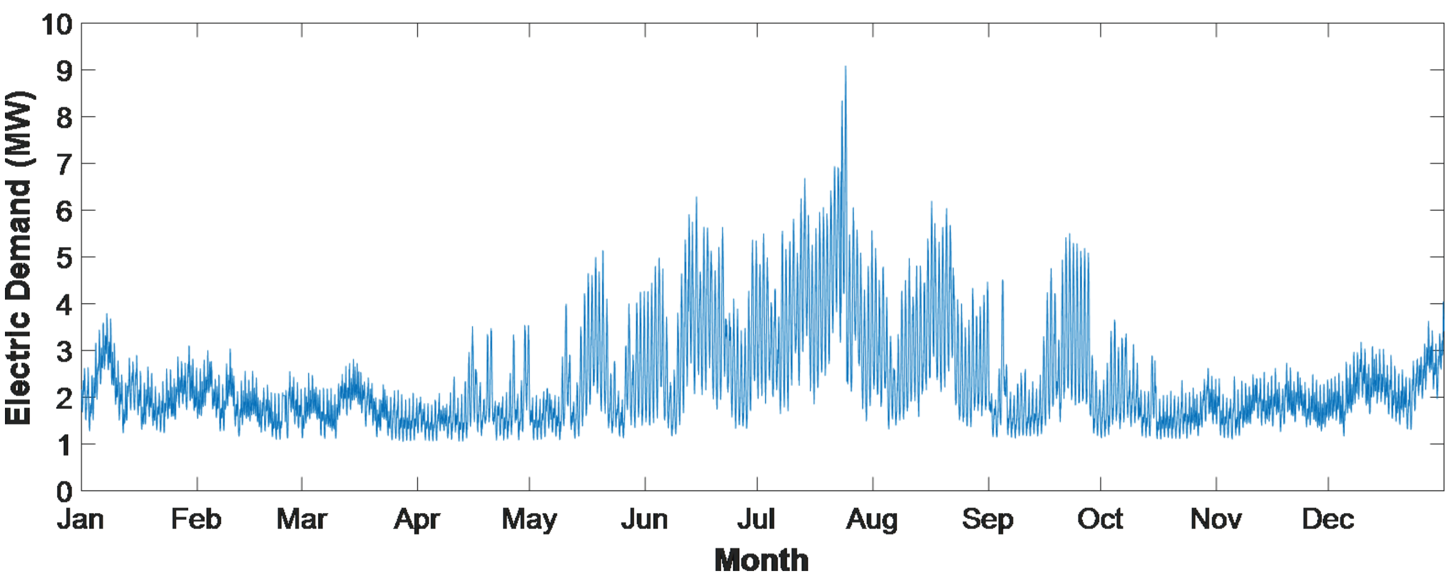
Figure 1: Google Earth Overview of Highland 1103 Circuit Distribution Infrastructure



LG&E operates 6,445 total miles of electric distribution lines making up 572 distribution circuits in and around Jefferson County serving approximately 411,000 electric customers.[7] Highland 1103 is a typical residential/small commercial circuit in that it has approximately 1600 residential customers and 240 small commercial customers, most of which also use natural gas, particularly for space and water heating. It is a 12.47kV circuit consisting of 9.26 total circuit miles (90% overhead, 10% underground and 30% 3 phase, 70% 1 and 2 phase).

Figure 2 displays the 5-minute load data on Highland 1103 for 2017 used in this study. It shows the summer peaking nature of the circuit as well as the lower winter electric demand due to natural gas space heating.

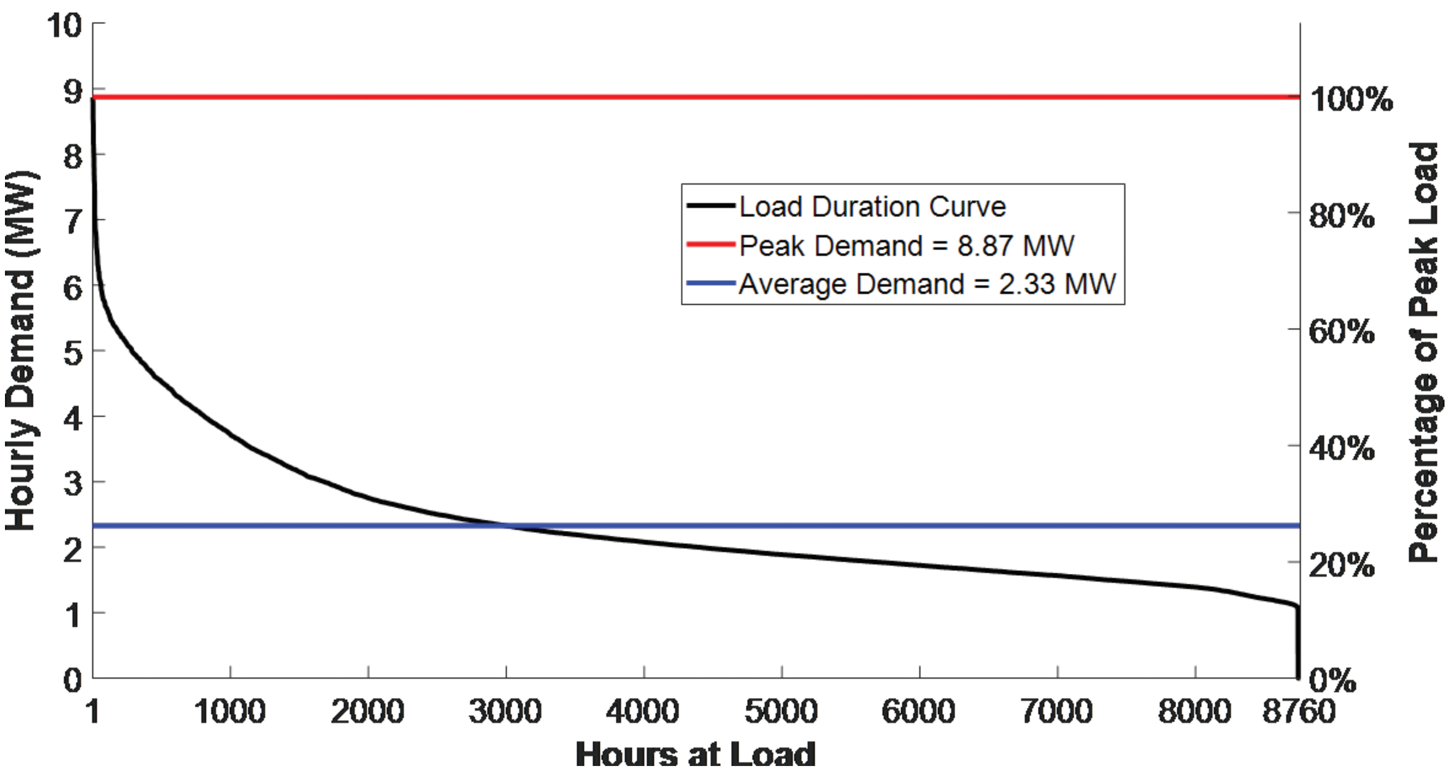
Figure 2: Five-Minute Electric Demand ("Load") for Highland 1103



[7] Data as of December 31, 2017. Includes pro-rata share of indirect or jointly owned assets.

Figure 3 displays average hourly electric demand in 2017 on Highland 1103 from highest to lowest in what is known as a load duration curve. The load duration curve shows that in 2017 the highest hourly load was 8.9 MW, the lowest hourly load was 1.04 MW, and the average hourly load was 2.3 MW. This circuit's load duration curve is typical for a summer peaking system with very high loads occurring in less than 500 hours of the year.

Figure 3: Load Duration Curve for Highland 1103

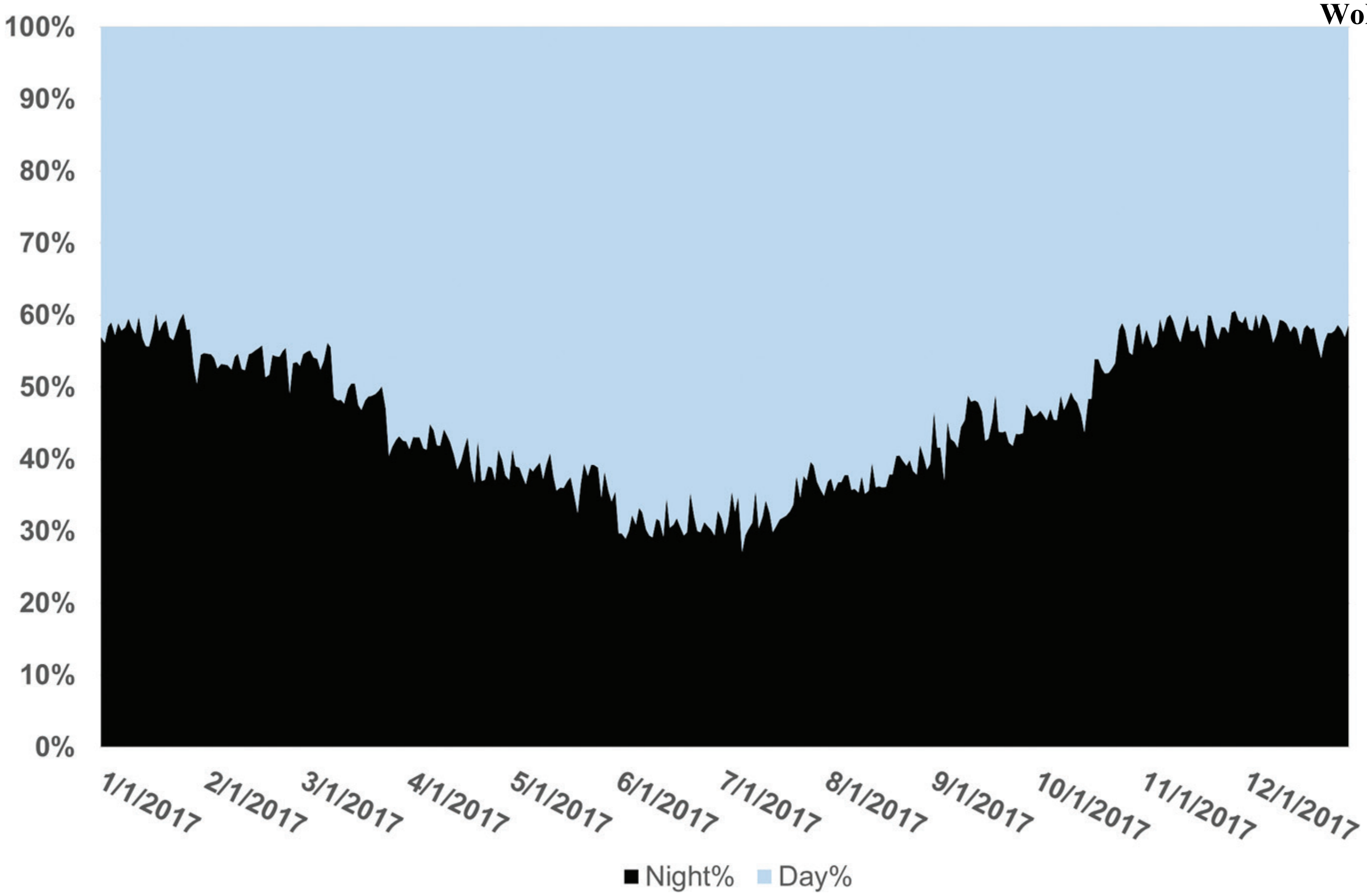


In 2017, base load generation (typically coal and combined cycle natural gas) satisfied the majority of the load shown in the load duration curve, and peaking generation capacity (simple cycle natural gas) served the peaks that only occur for a handful of hours in the year. If this circuit were to be served by 100% local solar generation then solar capacity would be needed to serve the peak hour and an additional amount of solar generation would be required to charge the energy storage required to meet customers' energy needs when the sun is down and on cloudy days. Therefore, much of the solar generation capability will be underutilized for a substantial portion of the year.

To further understand some of the challenges of just using local solar generation and energy storage, it is important to understand how much of Highland 1103 circuit's load occurs during daylight hours and nighttime hours. As shown in Figure 4, despite customers on this circuit predominately using natural gas for space heating, over 50 percent of their electricity is used during the night in winter months. Their usage at night decreases to around 35 percent to 40 percent in summer months as longer days and daytime air conditioning load increases the share of electricity used when the sun is up. Regardless of the season, the customers on this circuit use a substantial amount of energy when the sun is down, energy that must be stored in batteries.[8]

[8] The day/night energy profile of this circuit is comparable to the profile of the entire LG&E and KU system. See Figure 8 in PPL Corporation Climate Assessment at https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf

Figure 4: Proportion of Energy Consumed during Daylight and Nighttime Hours for Highland 1103



Evaluation Methodology

This case study uses actual five-minute load for 2017 from Highland 1103 and actual five-minute solar irradiance data measured from a NOAA weather station located in Versailles, KY. While the solar irradiance data is from a site that is about 50 miles from Highland 1103, it is representative of regional solar conditions that are adequate for this high-level case study. In general, it should be noted that this is a high-level conceptual study and is not meant to represent a final or optimal engineering or economic design. To design and size the equipment for an actual "off-the-grid" project would require additional analysis and engineering associated with issues such as, but not limited to, load diversity over time, motor starting/stall currents, fault current sources, protection, and over/under voltage risks. Table 1 shows the major assumptions used in preparing this case study.

Table 1: Major Assumptions for Case Study

	Assumption	Low Range	High Range
Utility-scale solar	$/kW installed[9]	810 (installed in 2030)	951 (installed in 2020)
	Annual capacity factor	~17% on average	
	Land requirement — acres / MW	3.2 Acres/MW (DC), 3.84 Acres/MW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Roof-mounted solar	$/kW installed[9]	1,493 (2030 Dollars)	2,306 (2020 Dollars)
	Average system size (per roof)	5 kW	15 kW
	Annual capacity factor	~17% on average	
	Space requirement — sq. ft./kW	~60 ft^2/kW (DC), 72 ft^2/kW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Utility scale Li-ion storage	$/kWh installed[9]	327 (installed in 2030)	435 (installed in 2020)
	Peak energy delivery — kW	1,000 kW	
	Energy storage — kWh	4,000 kWh	
	Battery size	0.015 Acres/MWh[10]	
	Useful life	10 years	15 years
In home Li-ion storage	$/kWh installed[9]	476 (installed in 2030)	634 (installed in 2020)
	Peak energy delivery — kW	5 kW (RS)	15 kW (GS)
	Energy storage — kWh	13.5 kWh (RS)	40.5 kWh (GS)
	Battery size	~9.5 ft2 per 13.5 kWh[11]	
	Useful life	10 years	15 years
Average retail rate in 2017 — cents/kWh	Residential	10.90 cents/kWh	
	Commercial	9.28 cents/kWh	
Distribution-only rate in 2018 — cent/kWh	Residential	25% of average retail rate	
	Commercial	26% of average retail rate	
Future retail rate escalation		2%	5%
Cost of Capital		4.40% (100% Debt Financing)	7.58% (Utility Cost of Capital)

When considering utility scale energy storage applications, it is important to be aware of its size and proximity to other structures. Employing the large number of batteries that would be necessary for these cases will require a keen attention to location, spacing, and fire mitigation strategies.[12] Figure 5 shows a typical utility-scale lithium-ion battery site with a 30 MW, 120 MWh (4 hours at peak discharge rate) energy storage system consisting of twenty-four 40-foot containers and a dedicated switchgear/control room, which is much smaller than the system needed for this circuit.

[9] Source: NREL's 2018 ATB (https://atb.nrel.gov/).

[10] Includes spacing required per fire codes, inverter footprint, and associated electrical infrastructure. Assumed 2400 ft2 for 1 MW, 4 MWh block.

[11] Residential and small commercial energy storage is typically wall-mount. 9.5 ft2 indicates wall space required. Actual footprint is dependent on local fire and building codes.

[12] "Big Battery Boom Hits Another Roadblock: Fire-Fearing Cities" https://www.bloomberg.com/news/articles/2018-05-18/the-big-battery-boom-hits-another-roadblock-fire-fearing-cities

Figure 5: Typical 30 MW, 120 MWh Lithium-Ion Energy Storage Site[13]

For all cases analyzed in this study, it is assumed that LG&E's distribution system costs will be included since the system is being relied upon to deliver solar energy to end-users and charge batteries. Other than escalation uncertainty, these costs are the same across all cases and do not drive differences. Also, this case study does not address potential stranded generation and transmission system costs that would be associated with a larger system-wide study.

The study assessed the cost of investments based on i) LG&E's cost of capital and ii) the cost of 100% debt financing. As identified in the "Potential Issues" section below, there are a number of possible ways that behind-the-meter rooftop and storage investments might be financed if owned by the property owner as well as some legislative and regulatory changes that could impact how utility system solar and storage might be owned and financed. This case study is focused on the scope and scale of the technology investments required to be 100% renewables and off-the-grid, not on the financial engineering of specific cases.

This study looks only at the 5-minute load profile from 2017. It does not address how future changes in load or load shape might impact system sizing and cost. For example, weather patterns could alter hourly and daily load shape and energy and widespread charging of electric vehicles would impact both the amount of electricity consumed as well as the daily load shape. Similarly, no assumption is made regarding future rate design or direct load control that might attempt to alter the load shape and the quantity of energy consumed. Lastly, no material change is assumed in natural gas utilization in the homes and businesses on this circuit that would impact electrical load.

Alternative Technology Solutions

Through initial modeling using the Highland 1103 circuit's 5-minute load and corresponding weather measured in 2017, it was determined that 75 MW (AC) of photovoltaic solar accompanied by 300 MWh of energy storage would be required to satisfy 100% of all electric demand in 2017 on this distribution circuit. This study assumes no equipment failures and zero generation capacity margin (for potential load changes), both of which would need to be considered for an actual sizing study. Figure 6 and Figure 7 show estimated solar production overlaid with electrical demand for representative winter and summer weeks. These figures show the variability in solar production day to day as well as by season and illustrate the need for such large solar and energy storage systems for this distribution circuit. A large solar and battery system is required in order to remain off grid during the winter, when there are fewer daylight hours, skies are more frequently overcast, the sun doesn't shine as brightly in the sky, and the majority of electricity demand occurs during the night. During the summertime, however, generation from this same system will exceed the neighborhood's electricity needs. When solar generation exceeds electric demand, the excess energy will be stored in batteries to be used to meet electricity requirements when solar generation is inadequate.

[13] Source: San Diego Gas & Electric.

Figure 6: Representative Week in January 2017 Showing Solar Generation and Electric Demand

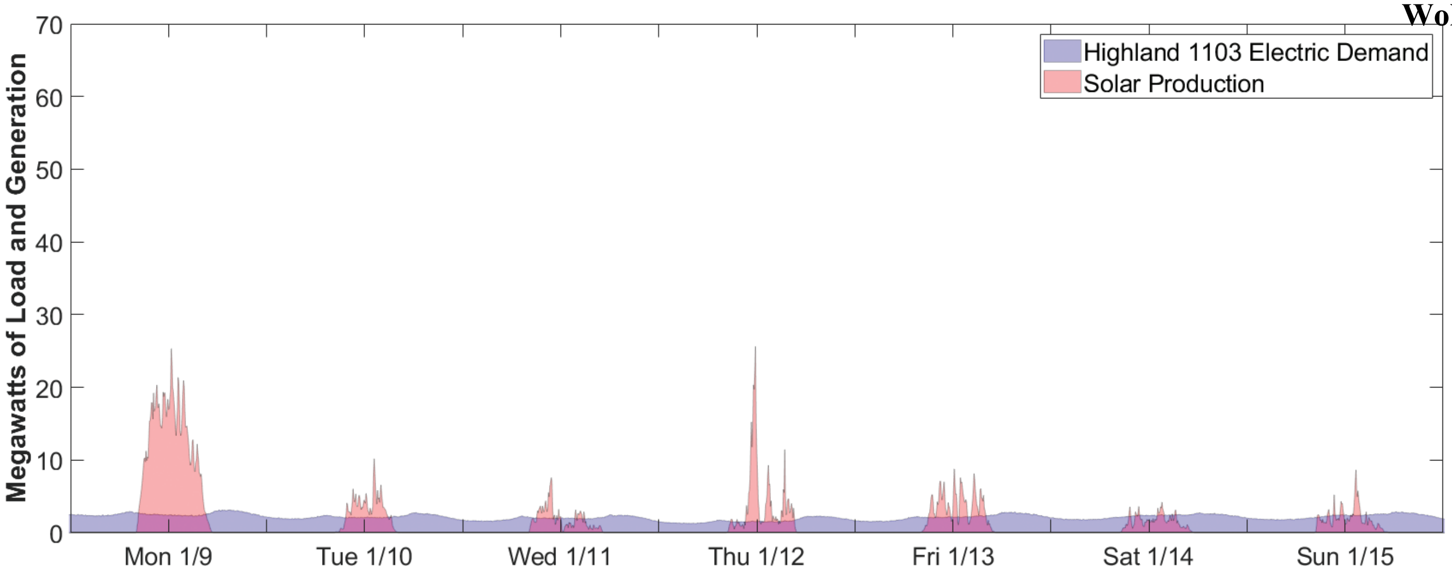
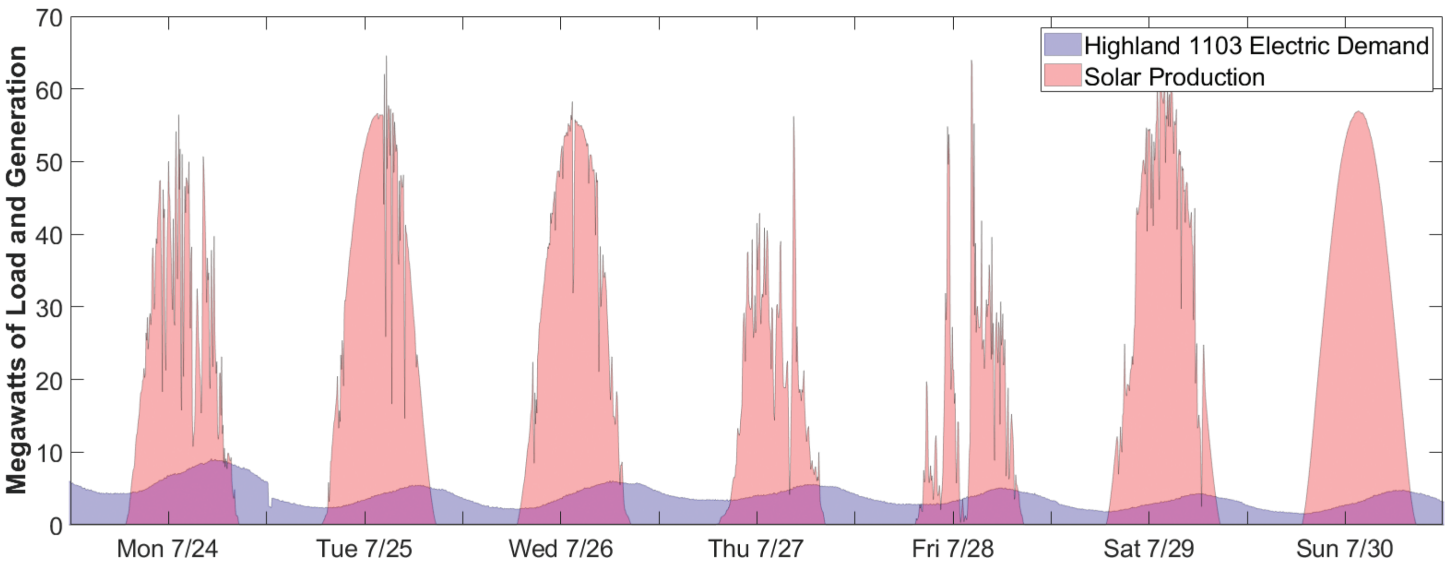


Figure 7: Representative Week in July 2017 Showing Solar Generation and Electric Demand



The study assumed each residential customer on the Highland 1103 circuit could install up to 5 kW of solar and up to 13.5 kWh of battery storage at their homes; non-residential customers were assumed to install up to 15 kW of solar and up to 40.5 kWh of battery storage. The range of results for the quantity of solar and storage technology is shown in Table 2. Note that the quantity of the required utility-scale battery storage is approximately two times the size of the typical storage facility shown in Figure 5.

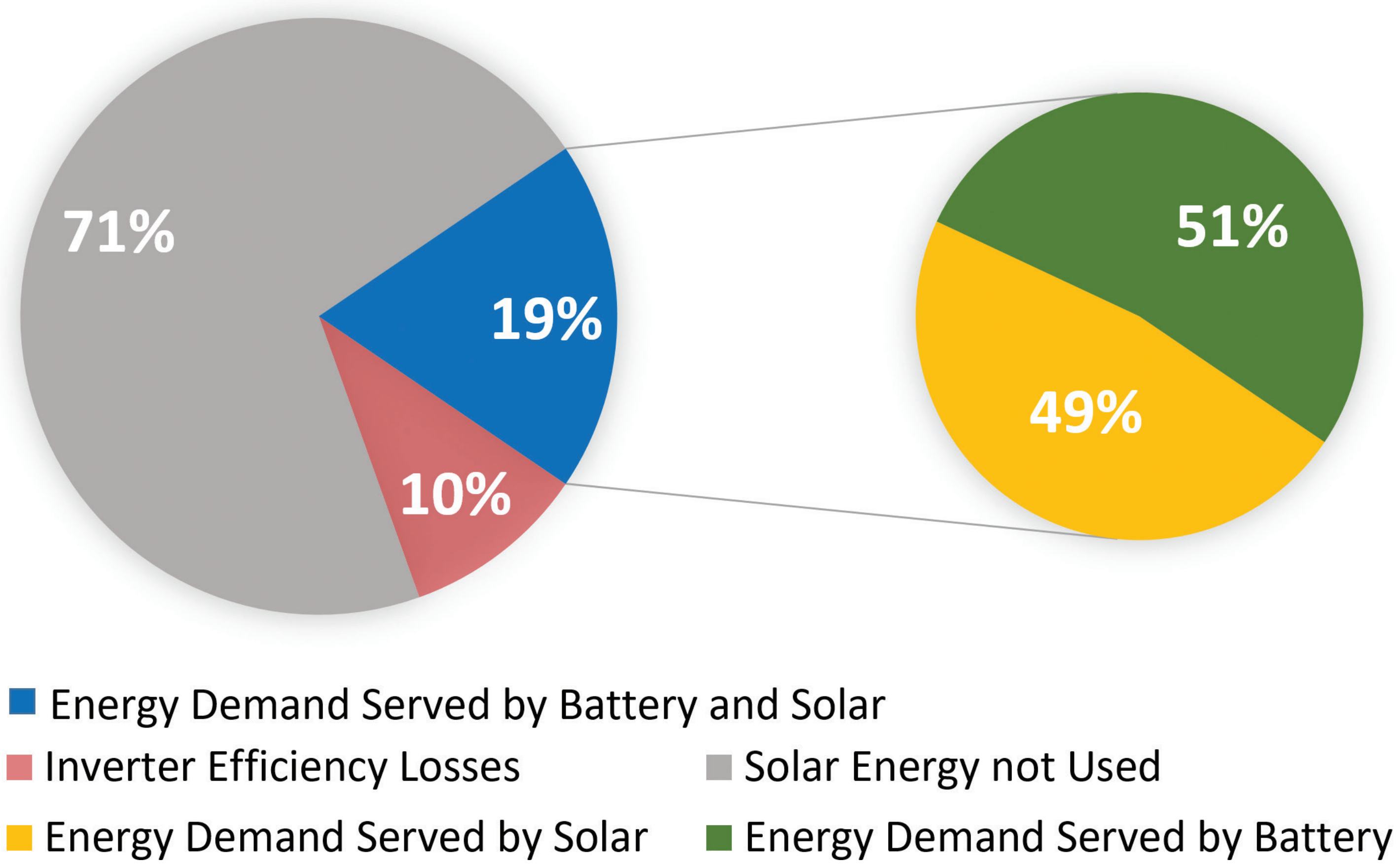
Table 2: Rooftop Solar/In-Home Storage Scenarios

% of Potential Rooftop Solar and In-Home Storage Capacity	Quantity of Solar and Battery Storage				Land Area Required for Utility-Scale Infrastructure (Acres)	Total Capital Cost $(millions)	
	Rooftop Solar (MW)	In-Home Storage (MWh)	Utility-Scale Solar (MW)	Utility-Scale Storage (MWh)		Nominal Cost in 2020	Nominal Cost in 2030
0%	0	0	75	300	293	202	159
50%	6	16	69	284	270	213	165
100%	12	32	63	268	246	224	172

Even assuming every home and business installs solar panels and storage, there is still a large need for utility scale solar generation and storage. In fact, the degree of home and business rooftop solar has a very limited impact on the quantity of utility scale solar required to reliably meet the circuit's energy needs. However, it does reduce the utility-scale infrastructure footprint by almost 50 acres which could be important in land constrained areas like Highland 1103.

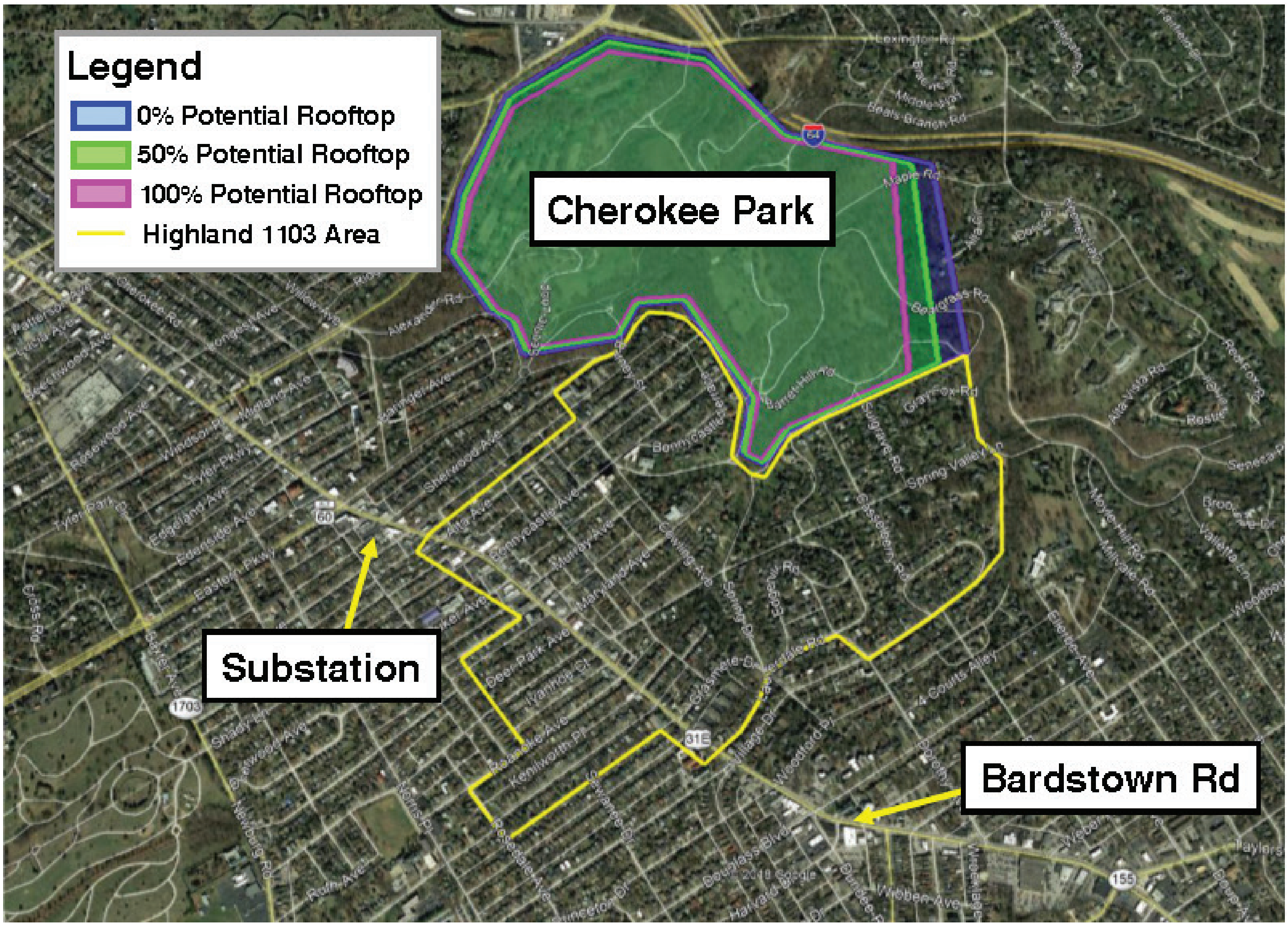
As shown in Table 2, approximately 75 MW of solar generating capacity is required to store sufficient energy to serve load during the winter when nights are longer and clouds are more prevalent. This capacity is approximately eight times larger than Highland 1103's summer peak of around 9 MW. This excess capacity can produce far more energy annually than is required to serve the customers' energy needs. In fact, as shown in Figure 8, approximately 71 percent of the potential solar energy would be unused. Figure 8 also shows that approximately 49 percent of the circuit's electricity would be generated directly by the solar panels with the remainder coming from storage. With so much energy flowing through storage, approximately 10 percent of solar generation would be consumed by inverter losses.

Figure 8: Distribution of Solar Energy Production



Because the interest in distributed solar and storage is often described in terms of local economic impact and reduced need for investment in transmission assets, it is important to understand the space requirements associated with isolating Highlands 1103 from the grid. Figure 9 shows the range of geographic space requirements for the three rooftop solar/in-home storage scenarios. The space required for the utility-scale facilities is large, even in the best-case use of rooftop solar/in-home storage. For this particular circuit, the only large vacant land area contiguous to the Highland 1103 circuit is Cherokee Park. LG&E is not recommending using the park in this manner but placing utility scale solar in other areas still impacts land use and would require additional electric lines to connect the facilities to this particular circuit. These costs are not included in this study.

Figure 9: Representative Land Use Required for Utility-Scale Solar and Battery Storage



Cost Comparison of Solar/Storage Cases to Remaining Connected to the Grid

Each of the rooftop solar with in-home storage scenarios in Table 2 were evaluated based on both LG&E's cost of capital (7.58%) as well as the cost of 100% debt financing (4.40%). The study was performed using NREL's cost forecasts for 2020 and 2030, which show continued future declines in both solar and energy storage costs.[14] In this study, the solar and battery storage systems were evaluated in a very favorable light. For example, all assets were assumed to have a useful life of 30 years, fixed operating costs for the solar and battery systems were ignored, and an inflation rate of zero percent was used to estimate nominal solar and battery storage costs in 2020 and 2030 from NREL's forecast. These and other assumptions are optimistic for the solar with storage concept (see "Favorability of Major Assumptions" for further discussion).

[14] NREL expects the costs of solar and battery storage to decline from 2020 to 2030 by 1.6% per year and 2.8% per year, respectively, in real terms.

In order to compare the cost of using 100% solar and storage to serve the electric load on the Highland 1103 circuit, the investments in solar and storage were levelized over 30 years and added to an estimate of the costs of maintaining and operating the existing distribution system that would still be required to serve load. These costs were then compared to a range of possible future costs of continuing to receive energy from the LG&E system. Note that the range of possible future LG&E costs are not predictions of future electricity prices but are meant to capture a range of possible future price paths over the next 30 years for comparing to the solar/storage off-grid cases.

Table 3 shows the levelized cost of electricity of serving the Highland 1103 load for all of the cases evaluated. These costs exclude the costs of operating and maintain the distribution system that would still be required. Not surprisingly, cases with a higher cost of capital have a higher levelized cost of electricity. The cases with rooftop solar and in-home battery storage require less land for utility infrastructure but are more expensive. Finally, the cost of installing the solar and battery systems in 2030 is less expensive than in 2020 due to the forecast of decreasing solar and battery storage costs.

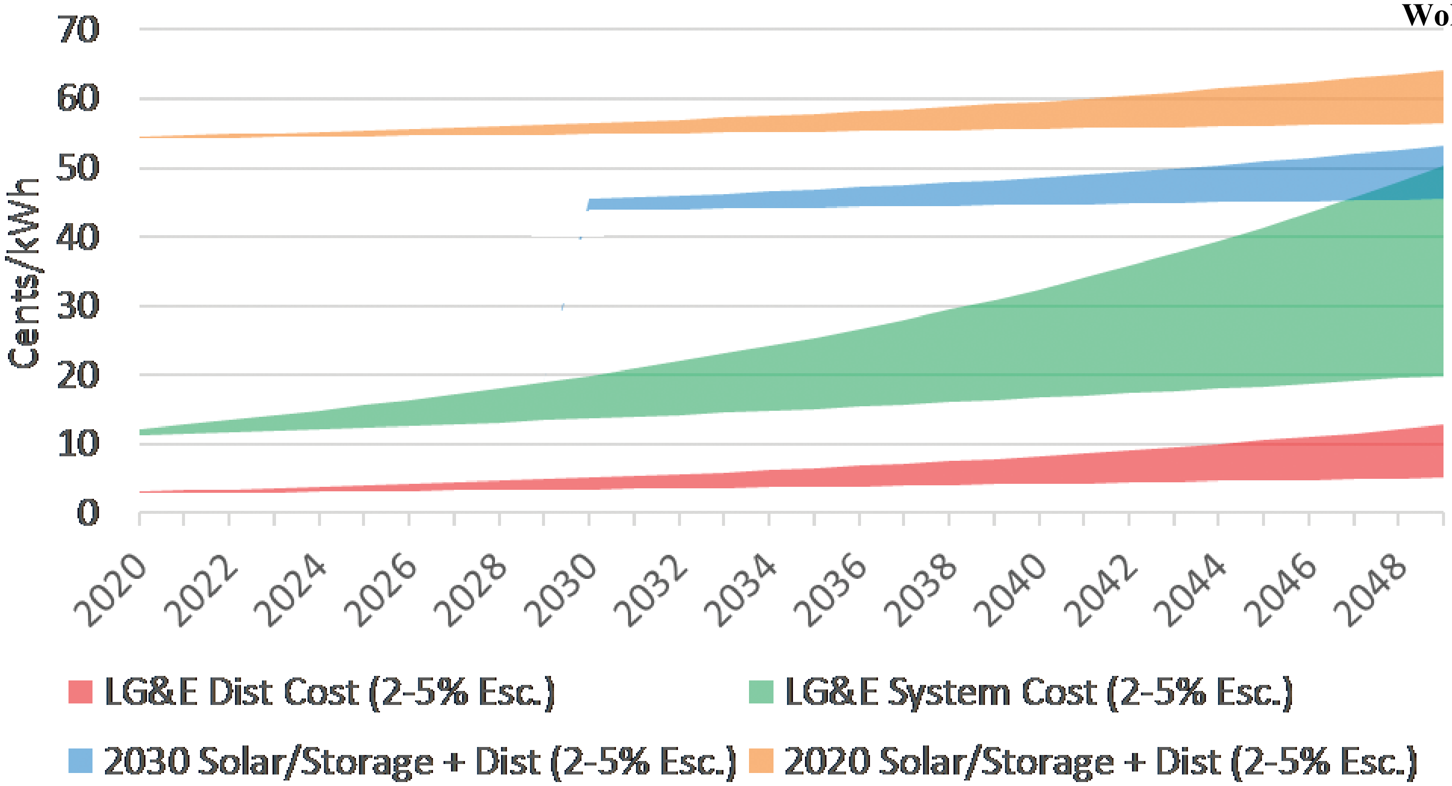
Table 3: Levelized Cost of Electricity excluding Distribution System Costs

Commission Year	Cost of Capital	% of Potential Rooftop Solar and In-Home Storage Capacity	Solar & Battery Storage System Cost Levelized Cost of Energy (cents/kWh)
2020	7.58%	0%	79.2
		50%	83.2
		100%	87.1
	4.40%	0%	51.4
		50%	54.0
		100%	56.6
2030	7.58%	0%	62.2
		50%	64.5
		100%	66.8
	4.40%	0%	40.4
		50%	41.9
		100%	43.3

Adding the cost of maintaining the distribution grid to the best 2020 and 2030 cases from Table 3 allows the comparison to a range of rate paths for staying on the existing LG&E grid. Figure 10 contains a range of rate paths for the LG&E distribution system in red and the entire LG&E system in green.[15] The ranges were created by escalating actual 2017 costs by 2 percent and 5 percent. The total costs for the best 2020 and 2030 cases were created by adding the range of distribution costs to the levelized costs in Table 3. This cost reflects the average cost of electricity for all customers on the Highland 1103 circuit.

[15] LG&E distribution system costs are assumed to grow proportionally with LG&E system costs.

Figure 10: Total Solar/Battery Storage Cost versus LG&E System Cost



As shown in Figure 10, the cost of isolating the Highland 1103 circuit from the grid and serving its electricity requirements with solar and battery storage is 2.5 to 3.5 times greater in 2030 than the LG&E system. Assuming LG&E's rates were to escalate at 5 percent annually, then it is possible that a solar and battery storage system installed in 2030 might be less expensive by the late 2040s. It should be noted that since 1990, LG&E average electricity rates have increased at an average rate of about 2.1 percent meaning that future rates would have to escalate at more than twice the historical rate in order for the solar and storage system to be even plausibly economical. The study also shows that with both solar generation and battery storage costs forecasted to decline, waiting as long as possible to make such investments would increase the probability of being economical compared to the LG&E system rates.

Favorability of Major Assumptions

In preparing the financial analysis for this study, a number of the operational and technology performance parameters were assumed to be favorable toward reducing the cost of using 100% solar generation and energy storage to serve Highland 1103. For example:

- The financial results presented assumed all panels, inverters, and batteries perform perfectly for 30 years. Based on what we know today, inverters and batteries are likely to have much shorter lives.
- The solar panels and battery storage were sized to exactly match 2017 actual load. Some contingency would need to be built in order to address load uncertainty and random equipment failure.
- No land cost was assumed for the utility scale solar generation and battery storage.

While recognizing that there would be incremental costs associated with addressing these issues in an actual project design, these items are also more uncertain and subject to change over time. Because the purpose of this case study was to evaluate the local solar generation and storage concept at a high-level, the Company did not want to distract from the study's fundamental purpose by explicitly trying to incorporate costs to address these issues.

Potential Issues Identified in Preparing this Case Study

As stated at the outset, this case study is a high-level analysis of the technology and financial implications associated with serving the load on a single LG&E distribution circuit. One of the benefits of preparing such a study is that it identified a number of issues and questions that a more detailed study would certainly need to address should such a project ever be considered in the future. Like this study, the questions and issues identified below are not meant to be exhaustive.

1. This study assumed that all roof-top solar and in-home storage was built overnight. In the real world, that would not occur so provisions (technical and financial) would need to be made to address changes (both increases and decreases) in the quantity of roof-top solar and in-home storage over time.

2. It was assumed that load (energy and shape) would be rather stable over 20 years. Provisions (technology and financial) would need to be put in place among the customers on the circuit to deal with material changes in load and load shape that would impact asset utilization and possibly cost recovery and future asset investment. Because the costs of this off-grid system are for all practical purposes fixed, changes in energy usage would not materially impact costs but could result in over- or under-collection of fixed costs. For example, unless load is forecasted to grow (say due to increased market penetration of electric vehicles or converting from natural gas to electric space heating), the economics of energy efficiency may not reduce overall costs but instead only shift fixed costs to other customers on the circuit depending on rate design.

3. Once such a system is created, the ability to undo it in the future may be limited or very expensive, so exit costs should be considered.

4. It was assumed for purposes of this study that all assets are owned and financed by LG&E but that may not have to be the case, particularly for roof-top solar and in-home storage. Some legal and regulatory issues would have to be addressed in this new type of system.

5. Because all assets were assumed to be owned and financed by LG&E there was no need to address compensation to individuals who invest their own funds in rooftop solar and in-house storage. However, in reality, it is highly likely that individual homeowners and business would invest their own funds and would seek compensation for contributions to supporting the circuit’s load.

Conclusion

The declining cost of solar generation and projections of future cost declines for battery storage along with increasing focus on CO_2 emissions have raised the interest of both customers and utilities identifying opportunities to deploy these technologies. To date, the vast majority of applications of these technologies have focused on applications that still require connection to the national power grid, a grid that today relies heavily on fossil fuel resources to reliably meet customers’ real time electricity needs. This study was a valuable exercise in identifying and evaluating the numerous technological, economic, land use, and transitional challenges that must be met in the future in order to scale solar and storage to the levels required to meet a sizable proportion of the nation’s electricity needs.

The report was prepared by staff from the following departments at LG&E and KU Energy: Electrical Engineering & Planning, Technology Research & Analysis, Generation Planning, and Sales Analysis & Forecasting.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 22

Responding Witness: William Steven Seelye

Q-22. Refer to the Supplemental Seelye Testimony Exhibits. Provide in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-22. See attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 23

Responding Witness: David S. Sinclair

Q-23. Refer to the Supplemental Testimony of David S. Sinclair (Supplemental Sinclair Testimony), page 7, lines 16–22, which discusses the method LG&E uses to determine the avoided generation capacity costs. Explain why the levelized cost of a simple cycle combustion turbine is listed instead of the levelized cost of a natural gas combined cycle station.

A-23. See Supplemental Exhibit DSS-2 at page 7. CT units are available around-the-clock and designed for fast starts and load following. As a result, CT capacity is oftentimes viewed as the purest form of capacity. A natural gas combined cycle facility simply adds a heat recovery steam generator ("HRSG") and a steam turbine to the simple cycle CT configuration in order to capture the CT exhaust heat to reduce the overall heat rate of the facility. In other words, the added capital cost of the HRSG and steam turbine are there to reduce energy cost and expand capacity, not enhance the reliability of the simple cycle CT. Thus, the cost of the CT is more appropriate when evaluating pure capacity economics.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 24

Responding Witness: David S. Sinclair

Q-24. Refer to the Supplemental Sinclair Testimony, page 11. Provide all research LG&E has conducted, or has been conducted on LG&E's behalf on the impacts of increasing penetrations of renewable energy.

A-24. The Companies have been studying renewable integration to be better prepared for a future with more intermittent generation. Specifically, in March 2019, the Companies began a partnership with the University of Kentucky (UK) Power and Energy Institute of Kentucky (PEIK) to evaluate the potential implications of increasing solar penetration and to determine the solar hosting capacity of the existing LG&E and KU generation and transmission portfolio. By analyzing 1-minute solar generation and customer usage data, the team found that the existing LG&E and KU portfolio can host up to 1,000 MW of solar capacity. The team's findings are summarized in the attached presentation. The team published the methodology for their analysis in the international, peer-reviewed, open-access journal, *Energies*, in December 2020 available for public download at https://www.mdpi.com/1996-1073/14/1/169 and also attached.

Intermittent Solar Penetration Study

Research Update 11/30/2020

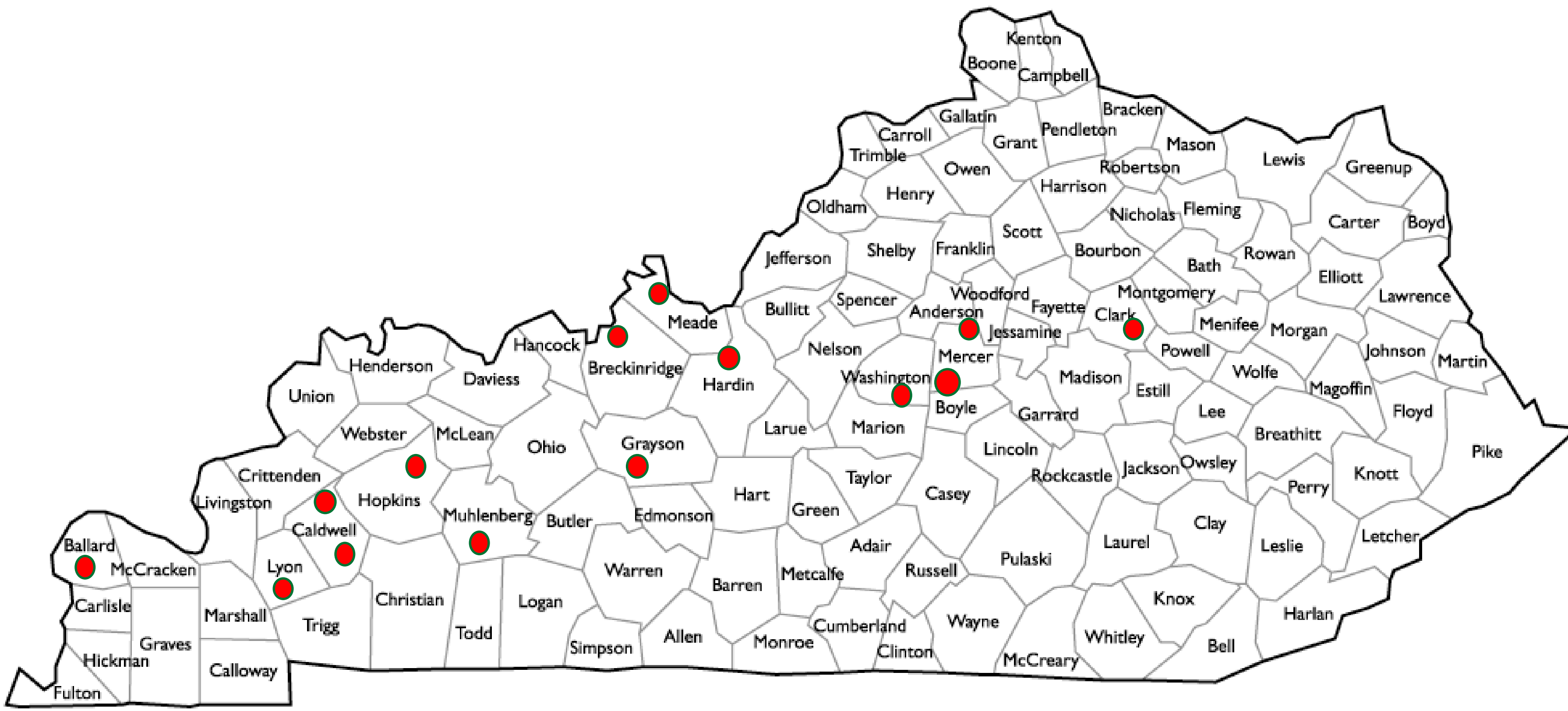
Research Partnership with the University of Kentucky
Power and Energy Institute of Kentucky
By Akeyo Oluwaseun, Aron Patrick, and Dan Ionel

Executive Summary

- **For ≤ 500 megawatts (MW) of solar**, the existing LG&E and KU generation portfolio—without operational changes—can regulate output to meet demand with negligible imbalances.
- **Solar penetration between 500 and 1,000 MW** would require some minor changes to generation unit operation, dispatch, and unit commitments with minor costs for generation to match load in real time.
- **Solar penetration above 1,000 MW**—to prevent significant imbalances—would require changes to the existing generation portfolio, including the retirement of older coal-fired generating units and addition of more-agile natural gas combined cycle units. As coal units are replaced with combined cycle units, the solar hosting capacity limit will be higher than 1,000 MW.
- If solar capacity were properly dispersed across the transmission system, there are no indications that solar penetration of ≤1,000 MW would create transmission problems. However, individual transmission system components, lines and transformers, are most-sensitive at the Point of Interconnection (POI) and neighboring regions of the system; thus, a detailed power flow analysis and circuit study is required for each project.
- The option to curtail surplus solar power, even at cost, is critical for increasing solar penetration.
- The addition of natural gas combined cycle units will increase the solar hosting capacity limit.
- The addition of lithium-ion energy storage, which respond instantaneously, can mitigate problems caused by solar intermittency including short-term generation imbalances, and transmission support with auto frequency-watt and autonomous volt-Var functionality.
- Dynamic energy management systems could also mitigate imbalance and facilitate solar penetration.

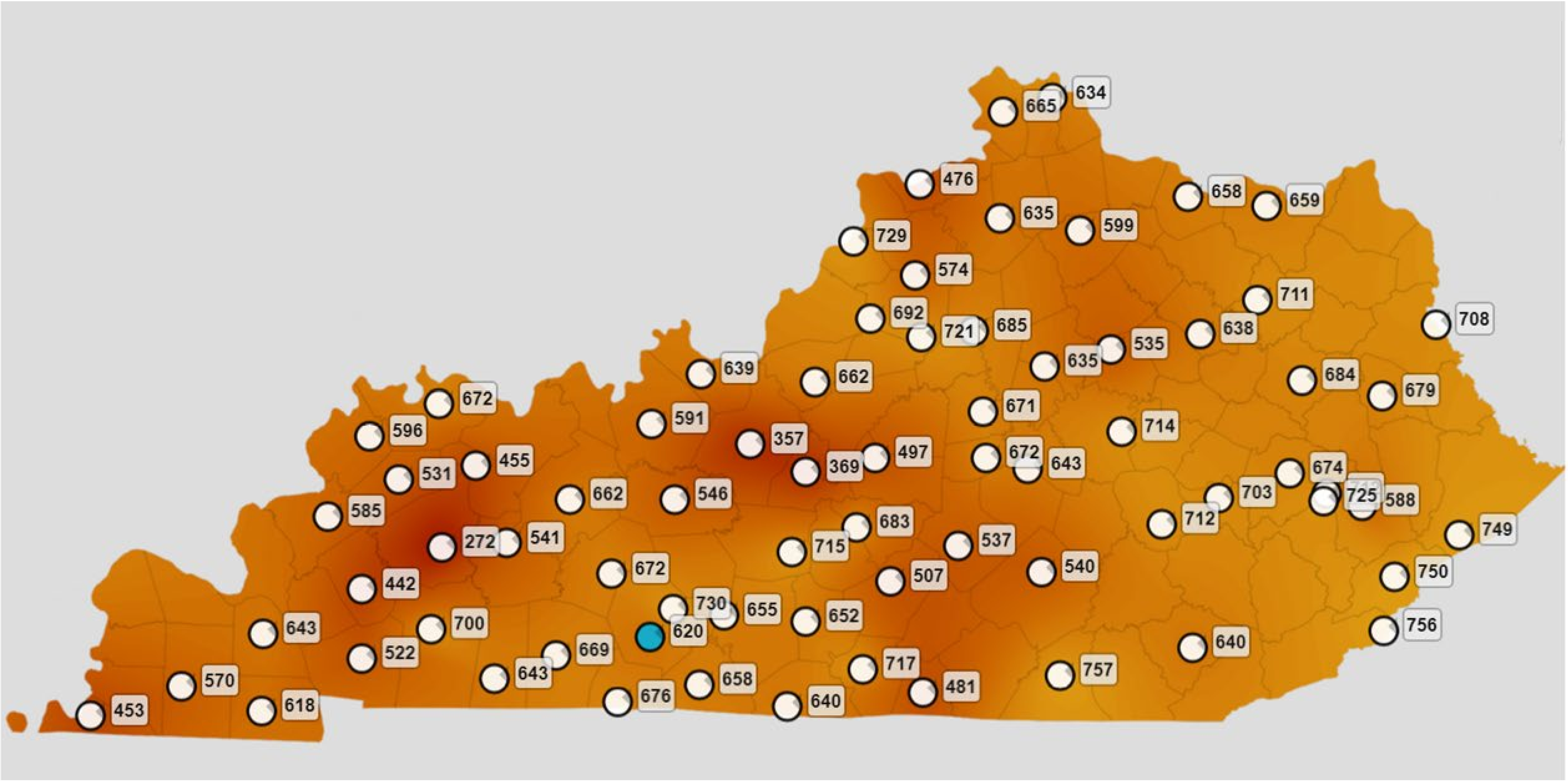
Solar Variation Data

Active PV Interconnection Queue



Case Nos. 2020-00349 and 2020-00350
Attachment 1 to Response to PSC-7 Question No. 24
Page 4 of 38
Sinclair

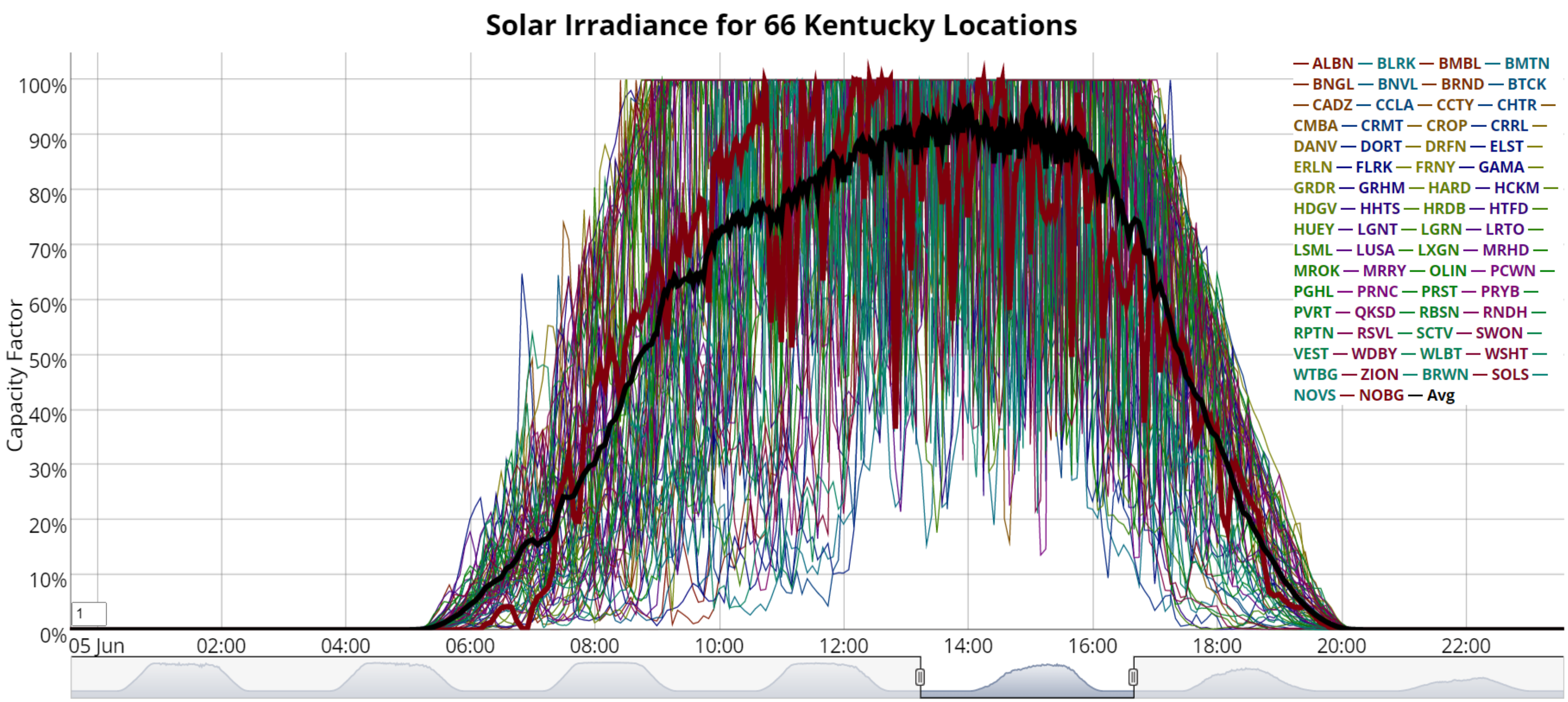
New Solar Data for 67 Kentucky Stations



Solar Irradiance Data from WKU KY Mesonet, NOAA, and LG&E and KU

Case Nos. 2020-00349 and 2020-00350
Attachment 1 to Response to PSC-7 Question No. 24
Page 5 of 38
Sinclair

Interactive Data for 67 Kentucky Stations



Open Interactive Data: https://teams.sp.lgeenergy.int/sites/RD/Plots/KY_Solar_Dash.html

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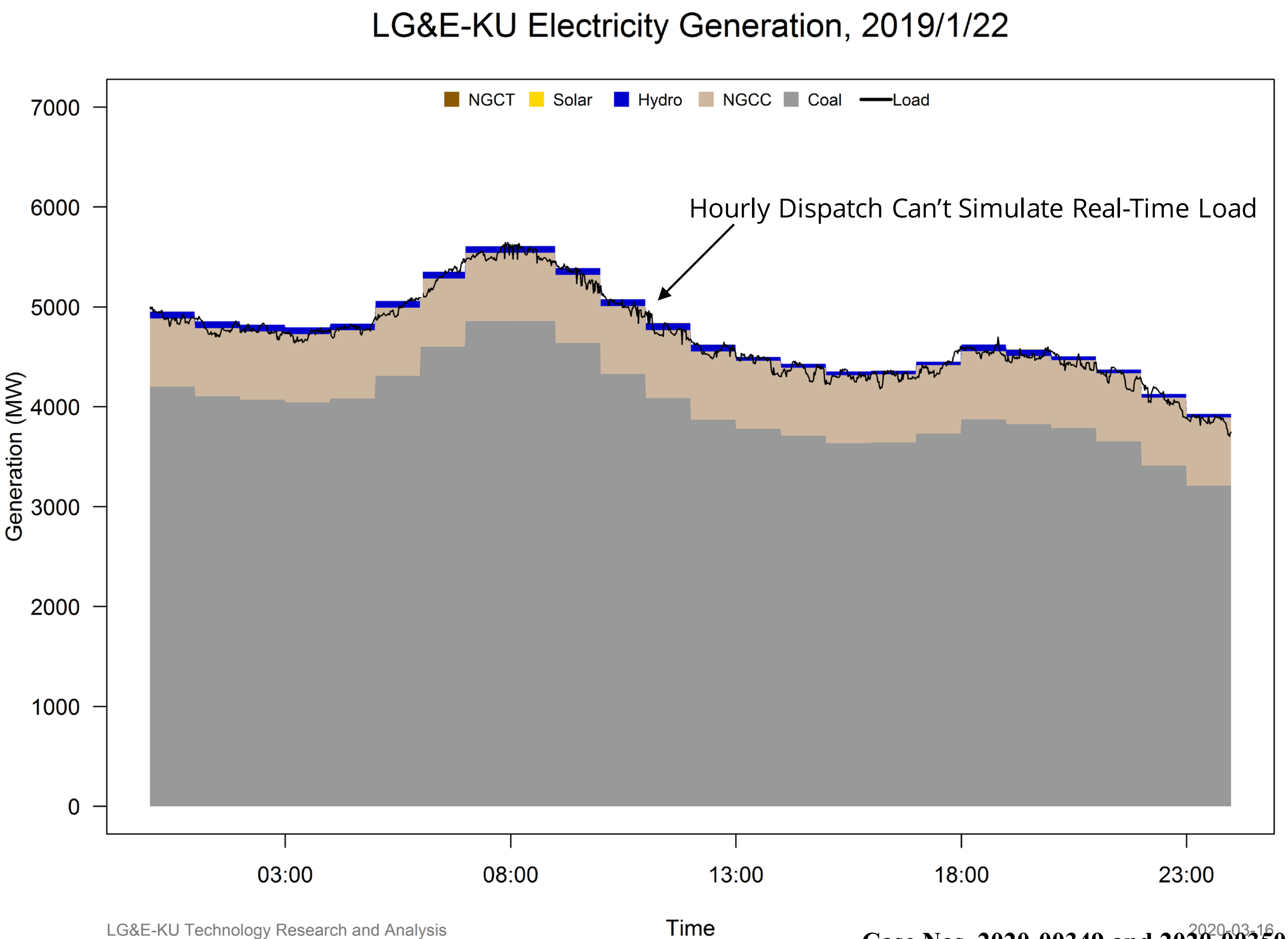
Generation Impacts

Hourly Dispatch by Fuel in Prosym



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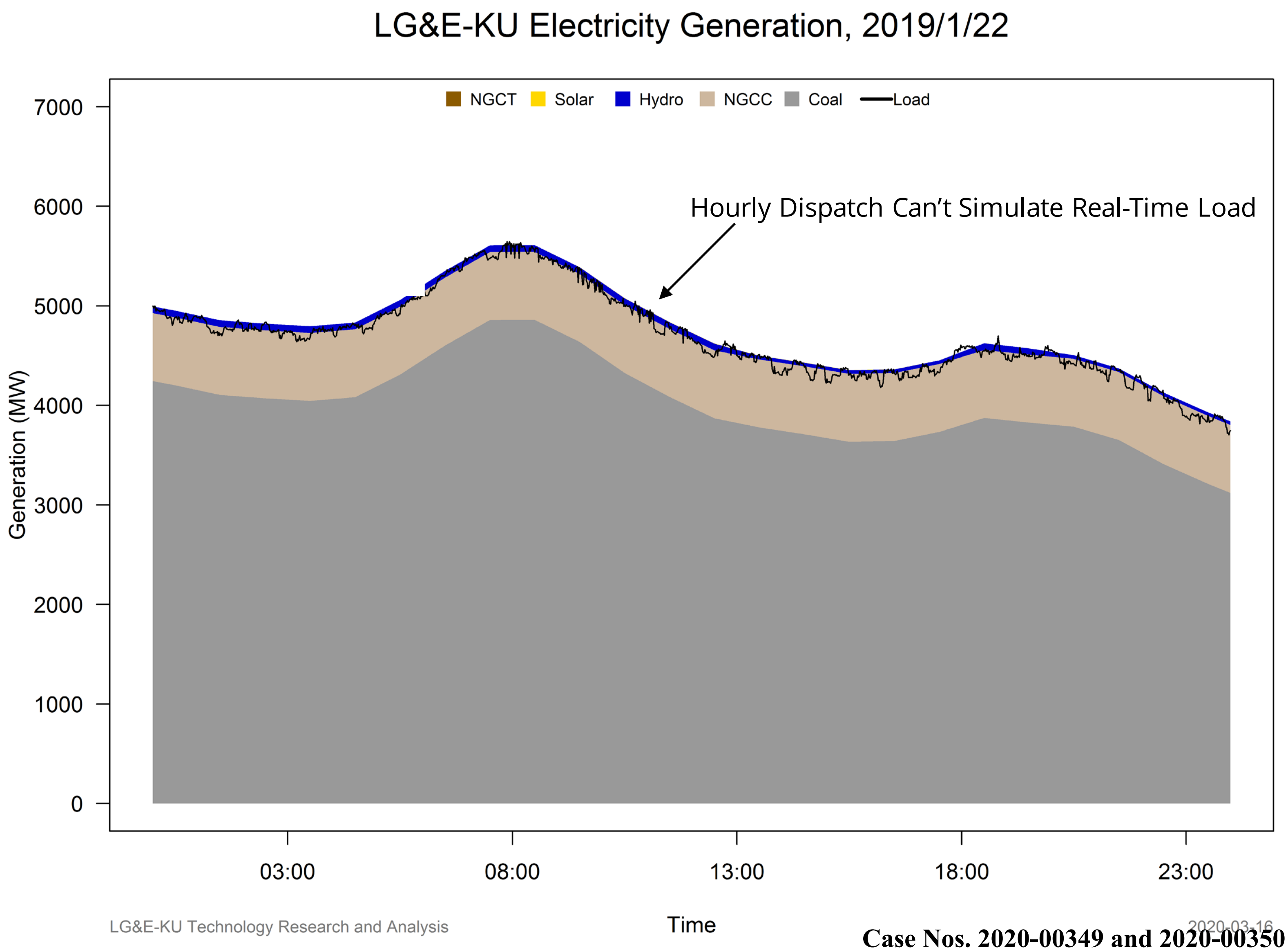
Hourly Dispatch by Fuel in Prosym - Interpolated



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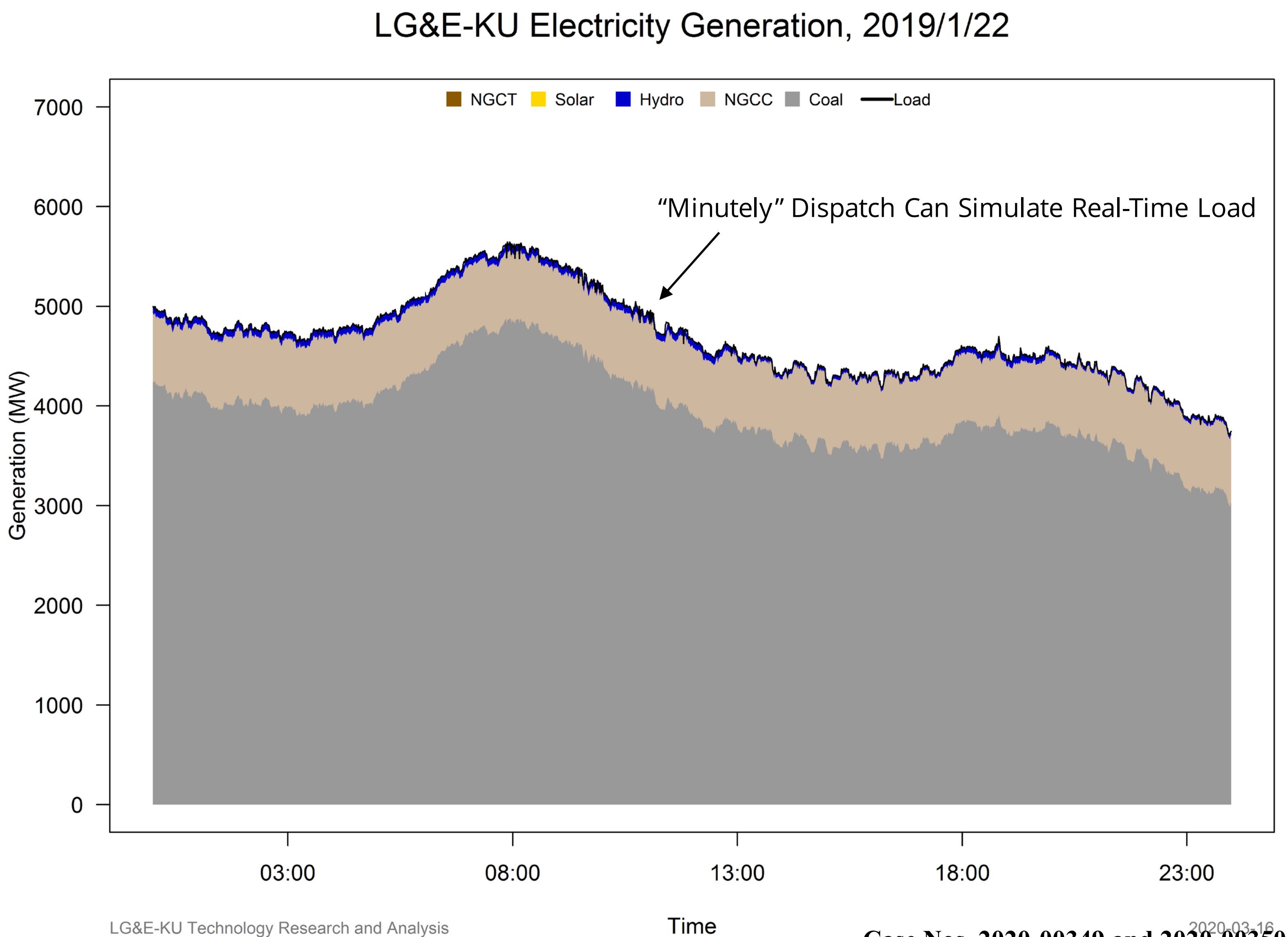
New "Minutely" Dispatch by Fuel



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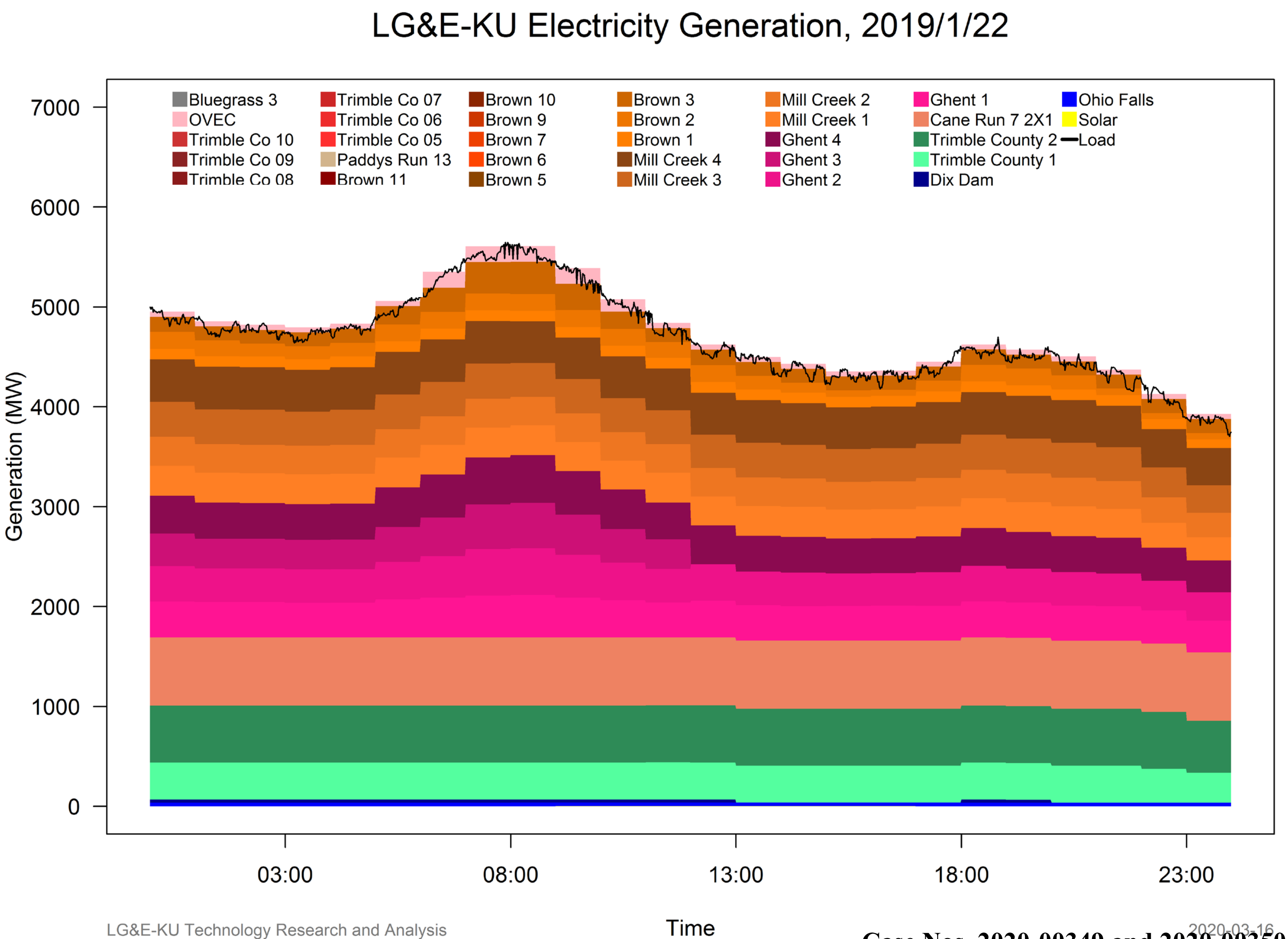
Hourly Dispatch by Unit in Prosym



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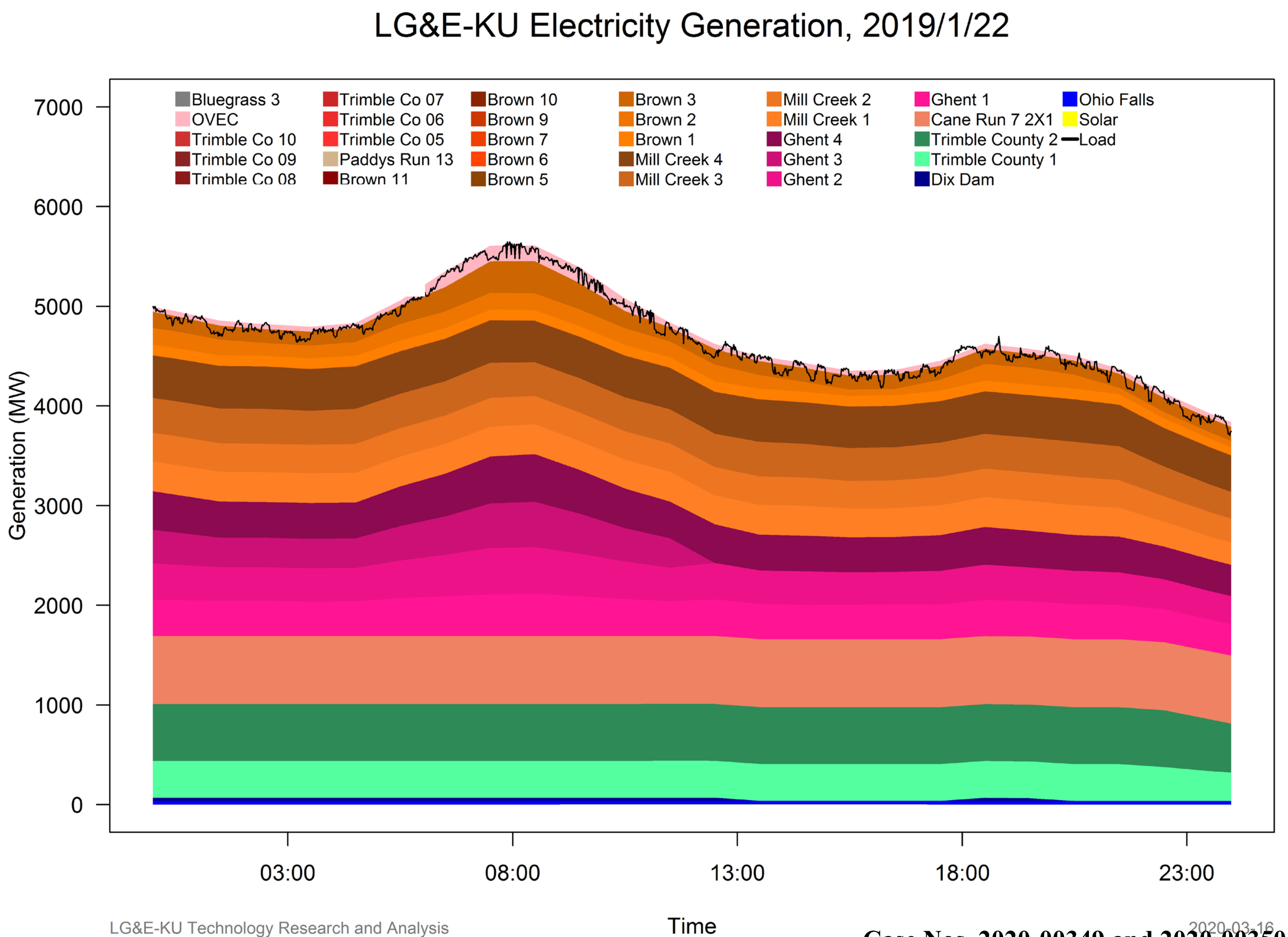
Hourly Dispatch by Unit in Prosym - Interpolated



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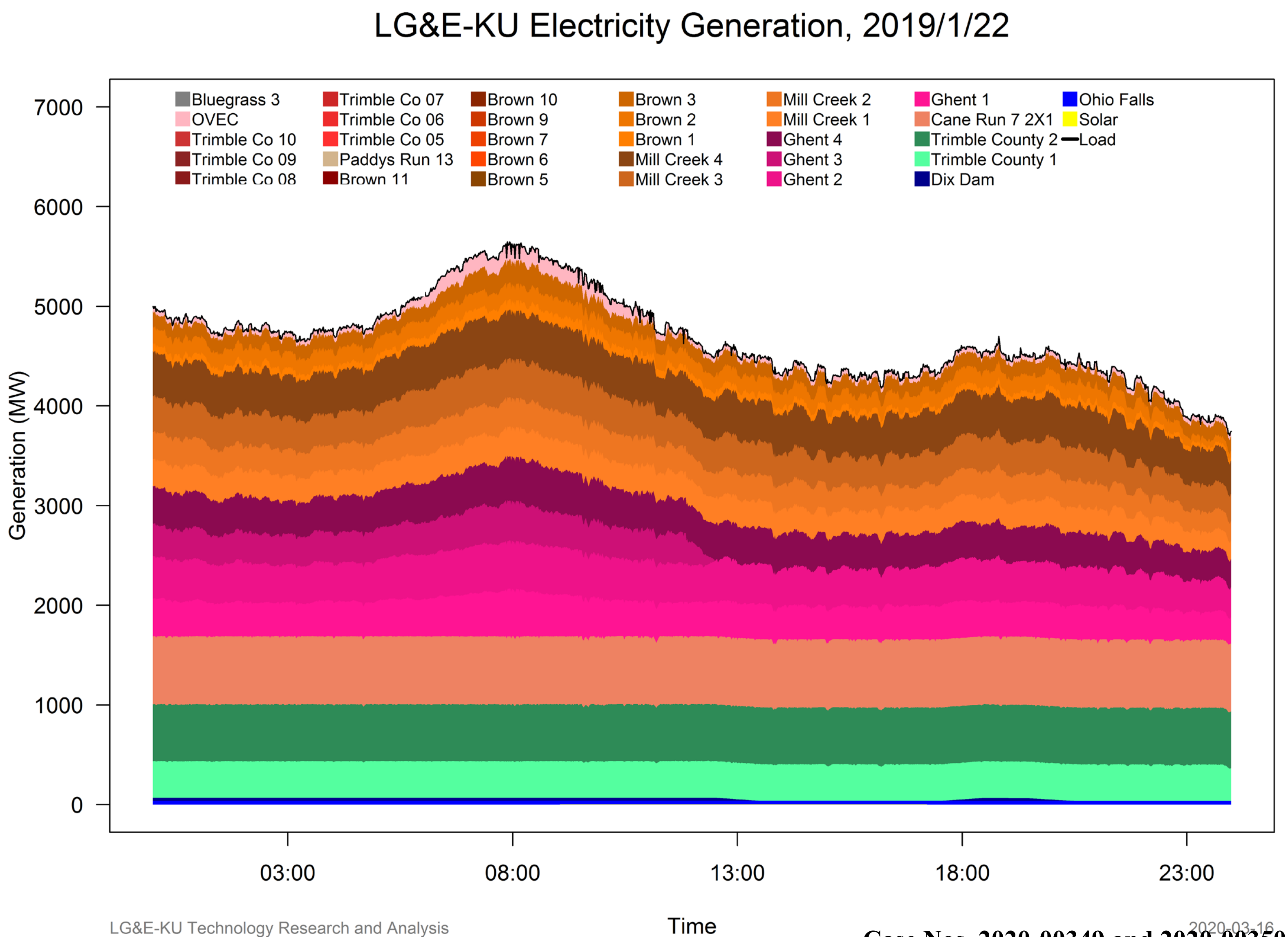
"Minutely" Dispatch by Unit



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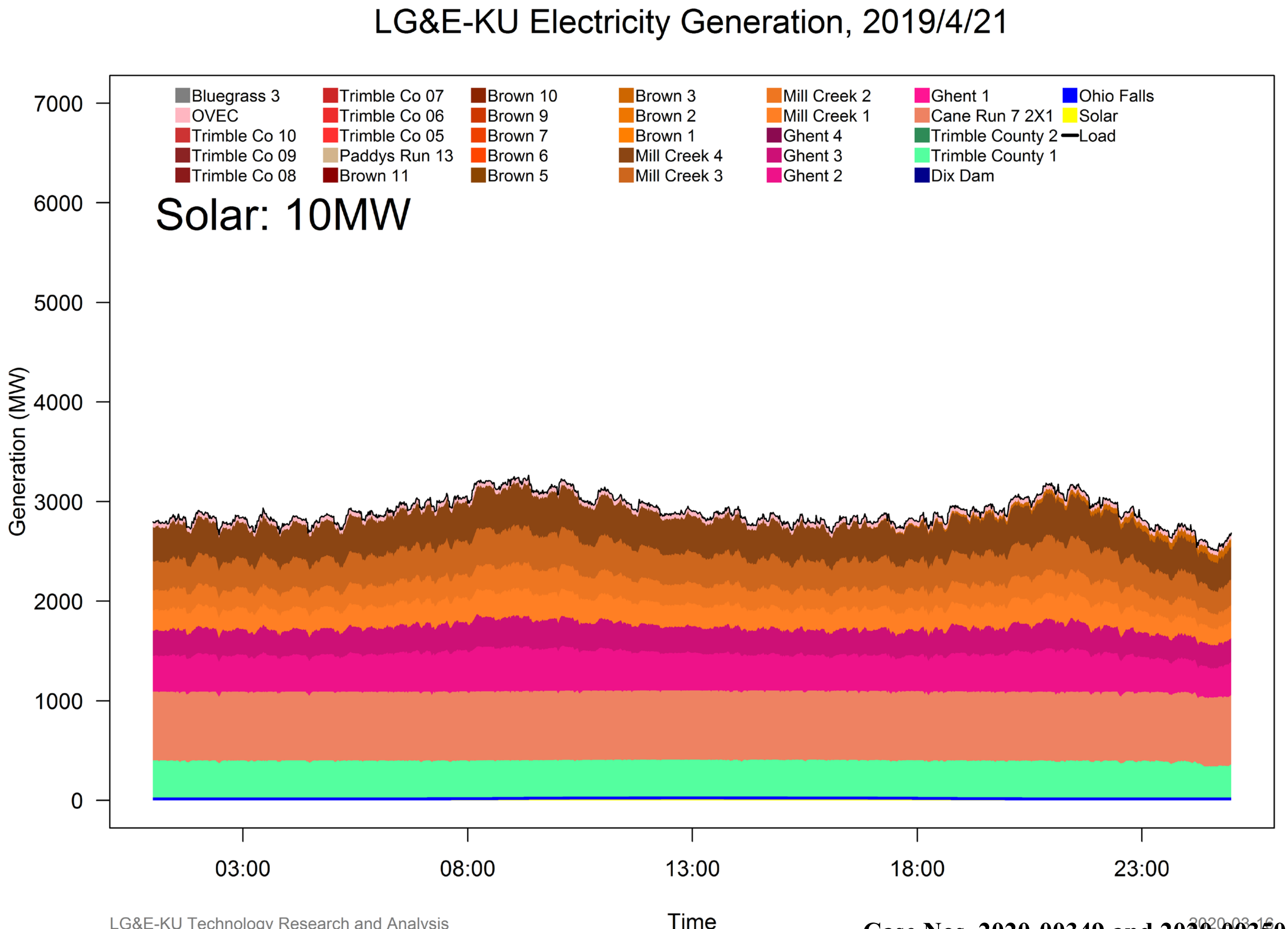
LG&E KU PPL companies

Example Solar Impact by Unit – April – 10 MW Solar



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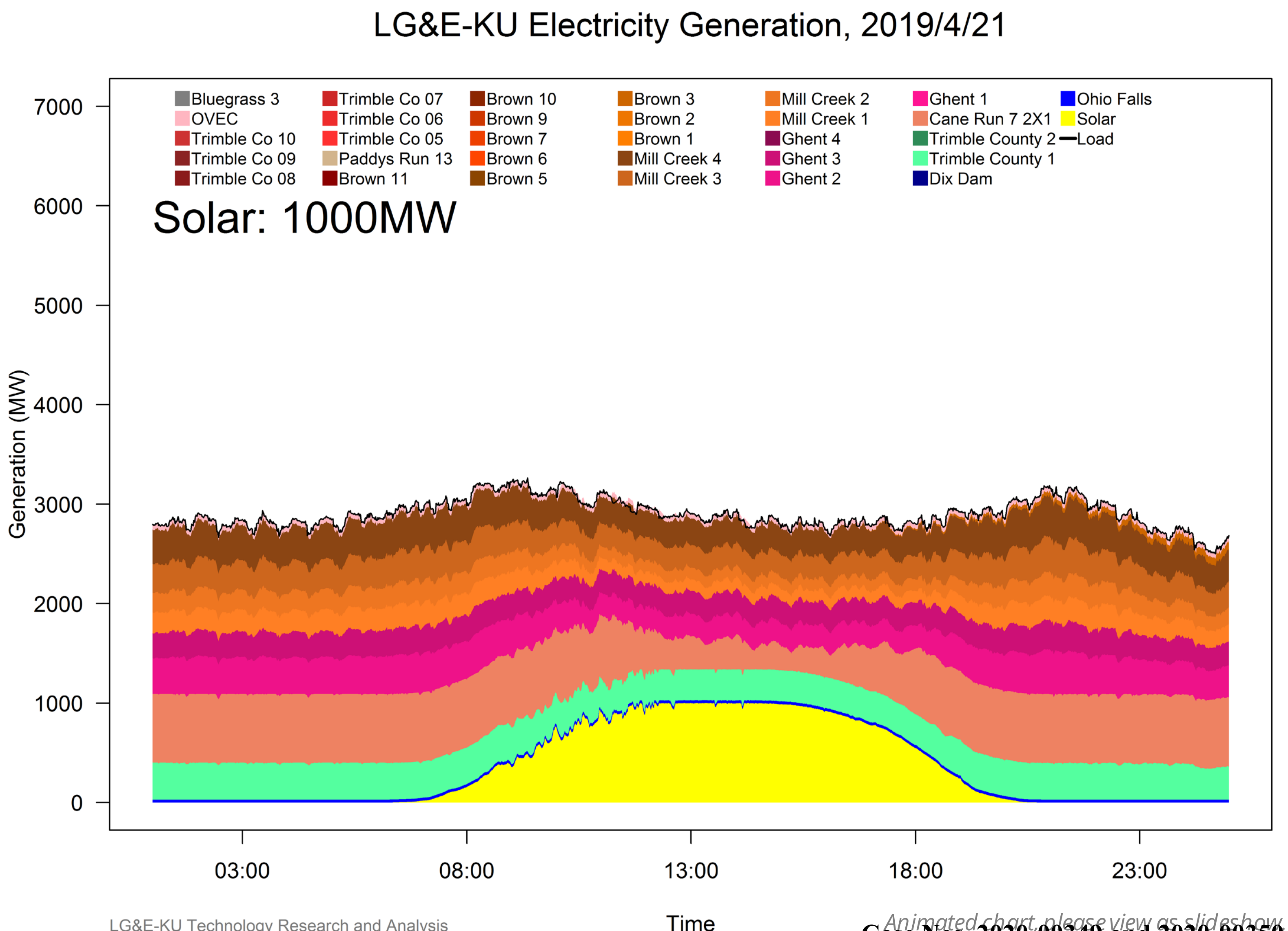
Example Solar Impact by Unit – April – 1000 MW Solar



Animated chart, please view as slideshow

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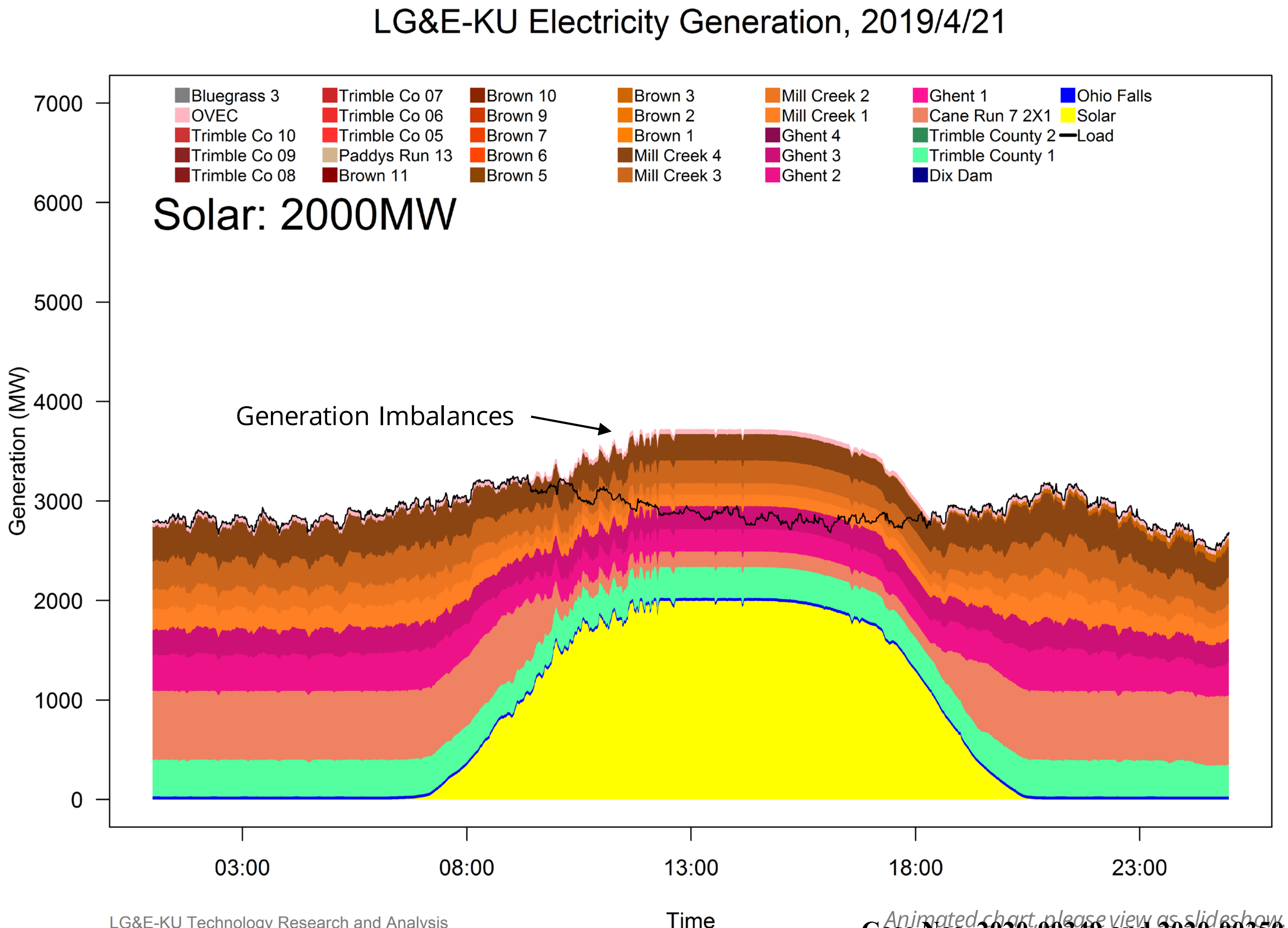
Example Solar Impact by Unit – April – 2000 MW Solar



Animated chart, please view as slideshow

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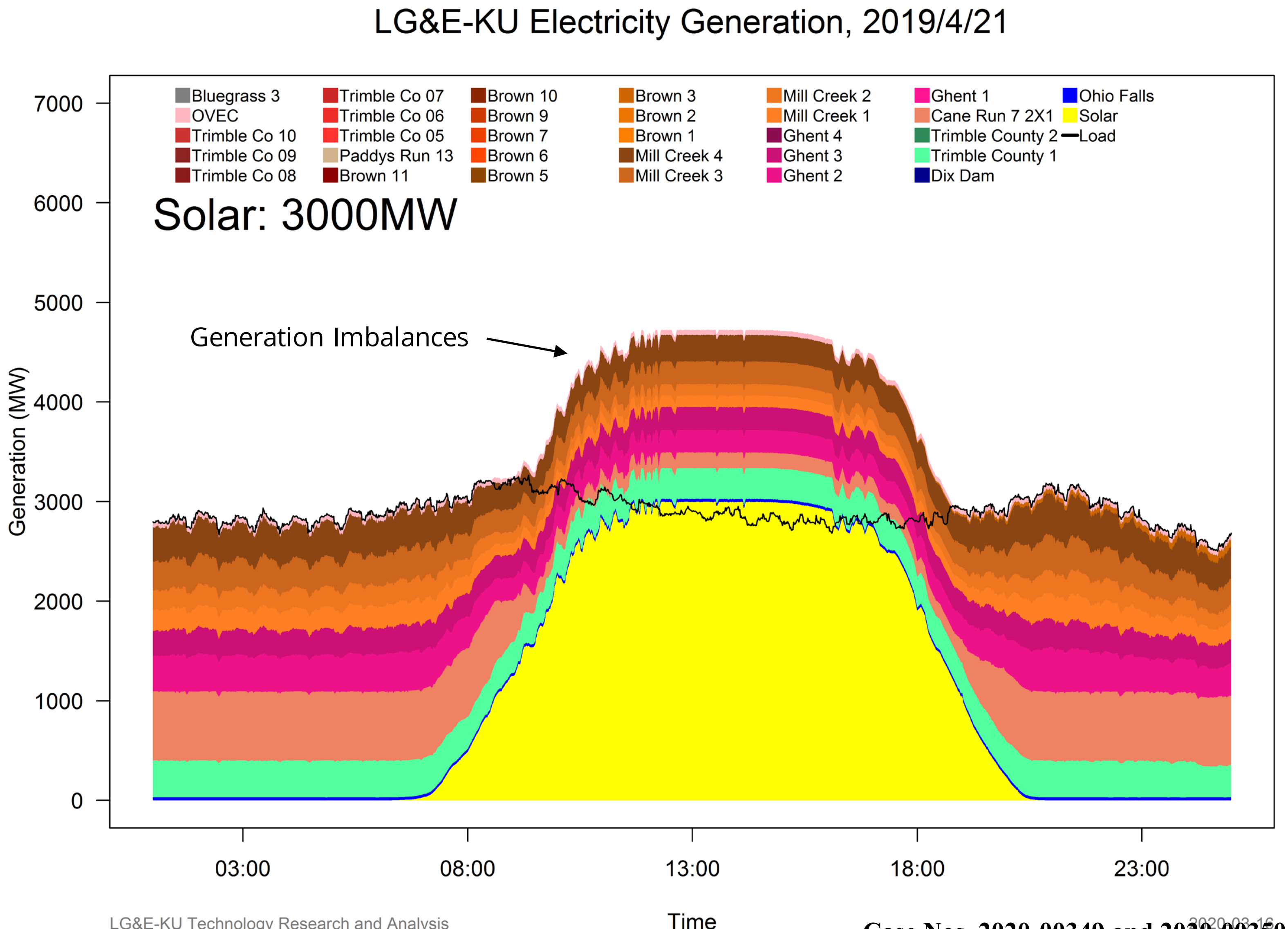
Example Solar Impact by Unit – April – 3000 MW Solar



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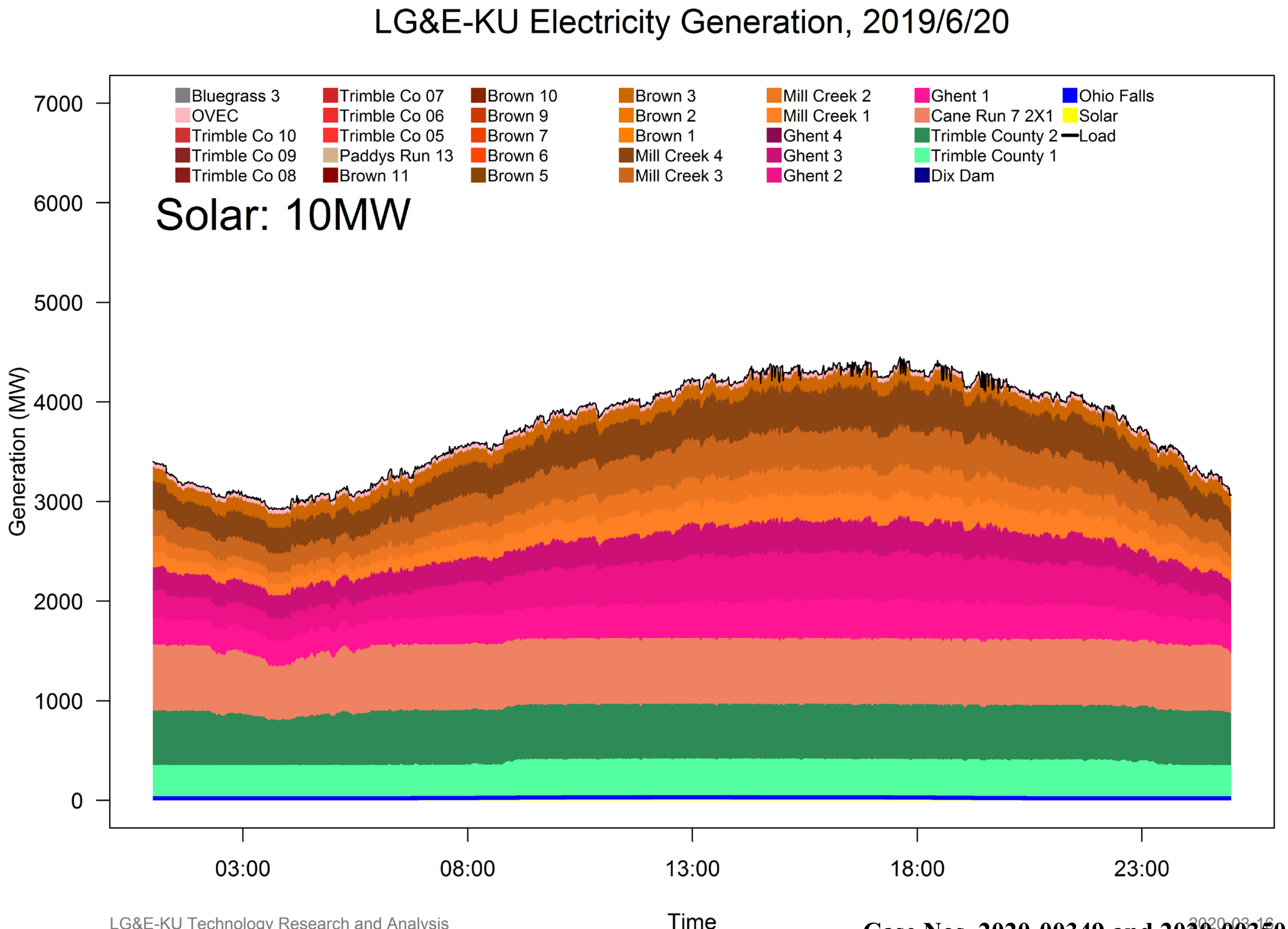
Example Solar Impact by Unit – June – 100 MW Solar



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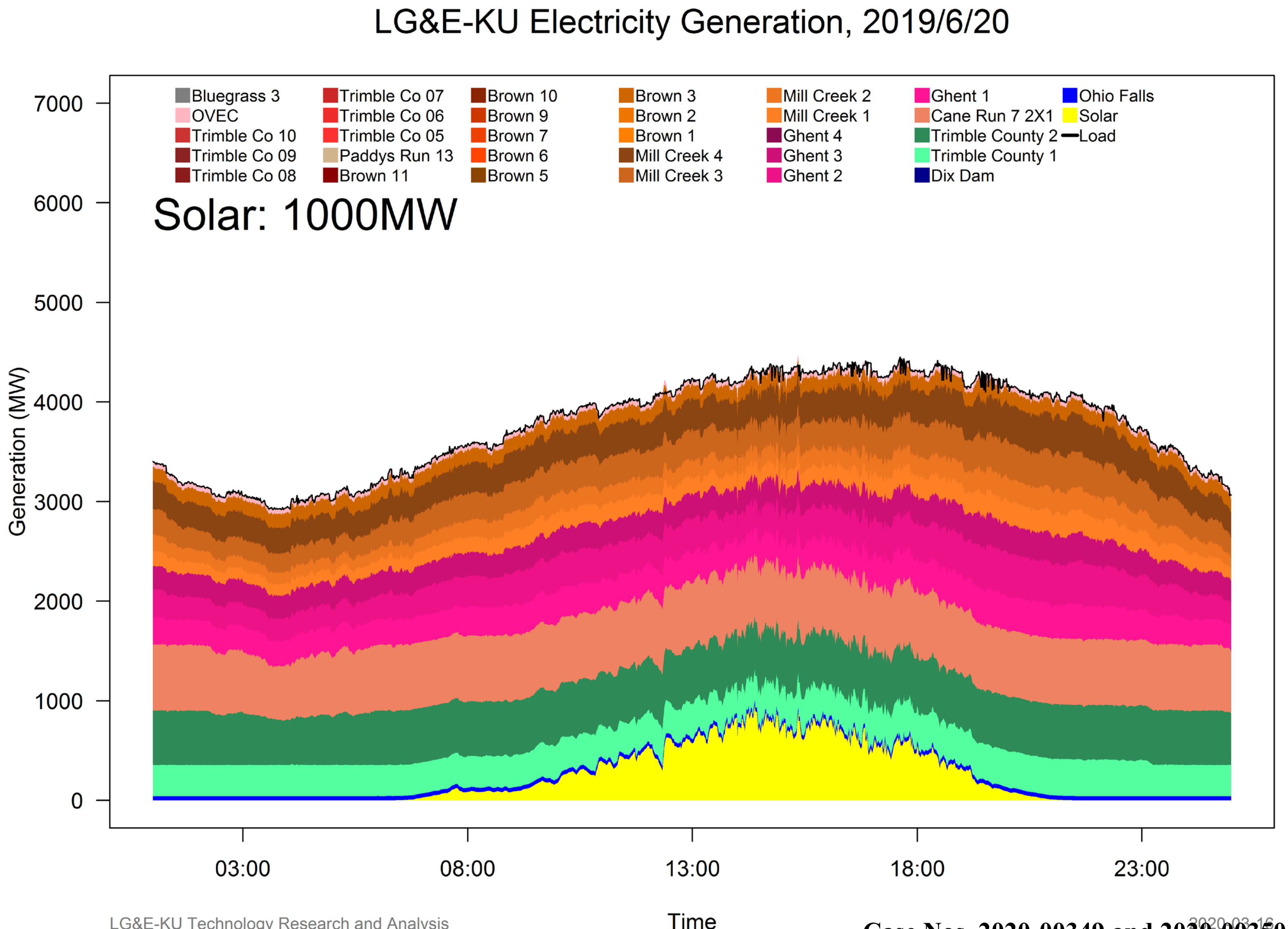

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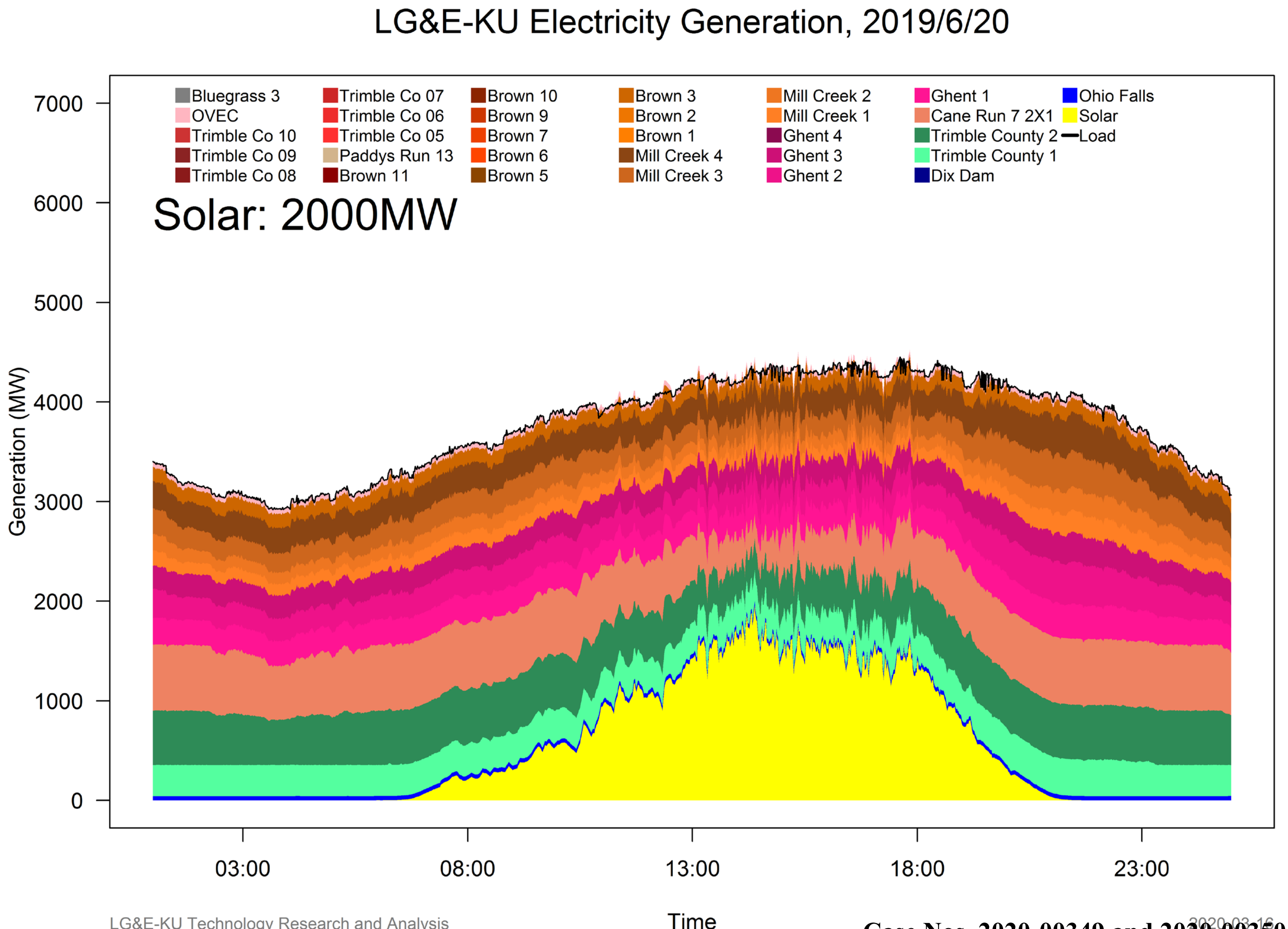
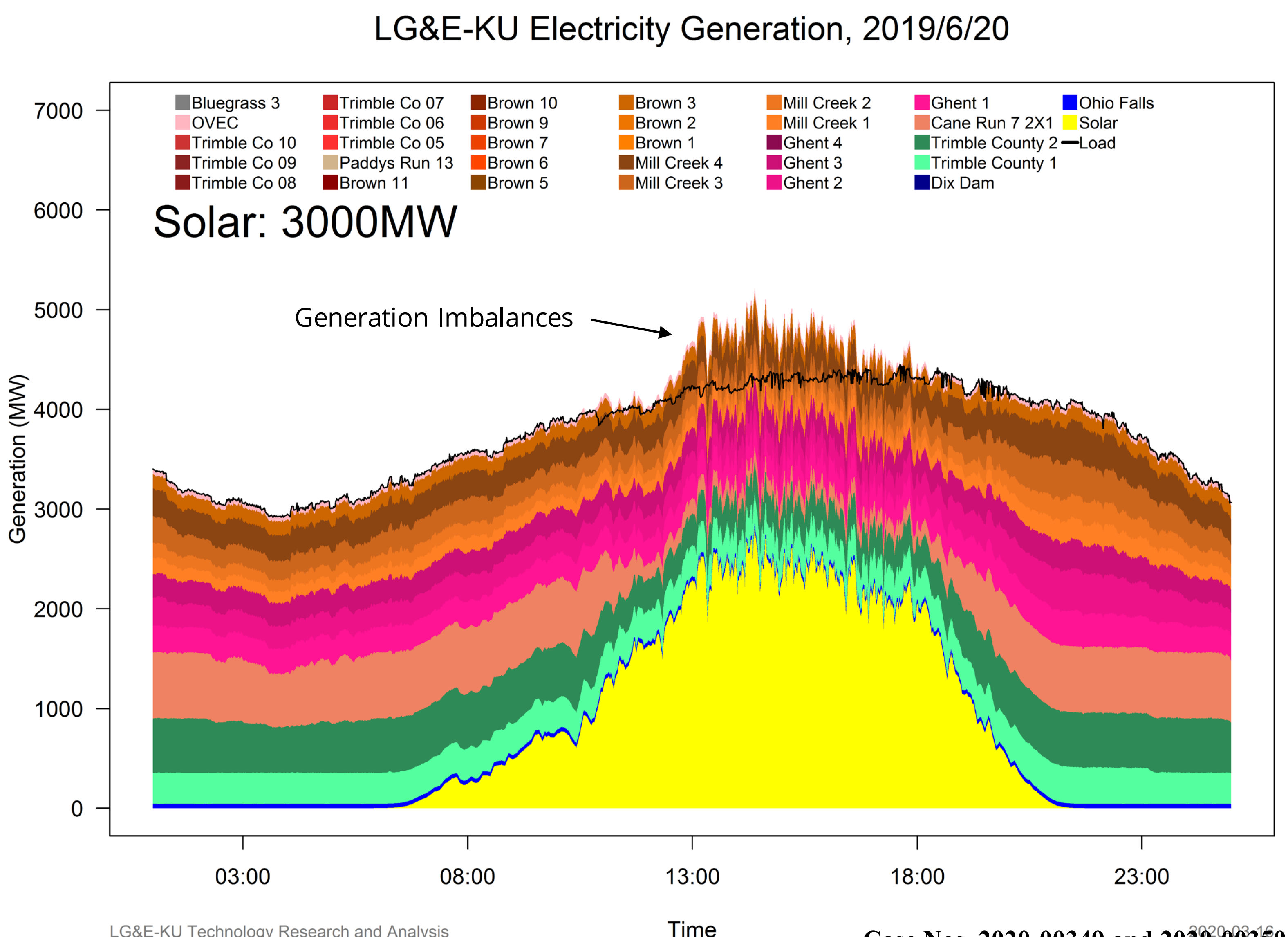
Example Solar Impact by Unit – June – 2000 MW Solar



Example Solar Impact by Unit – June – 3000 MW Solar



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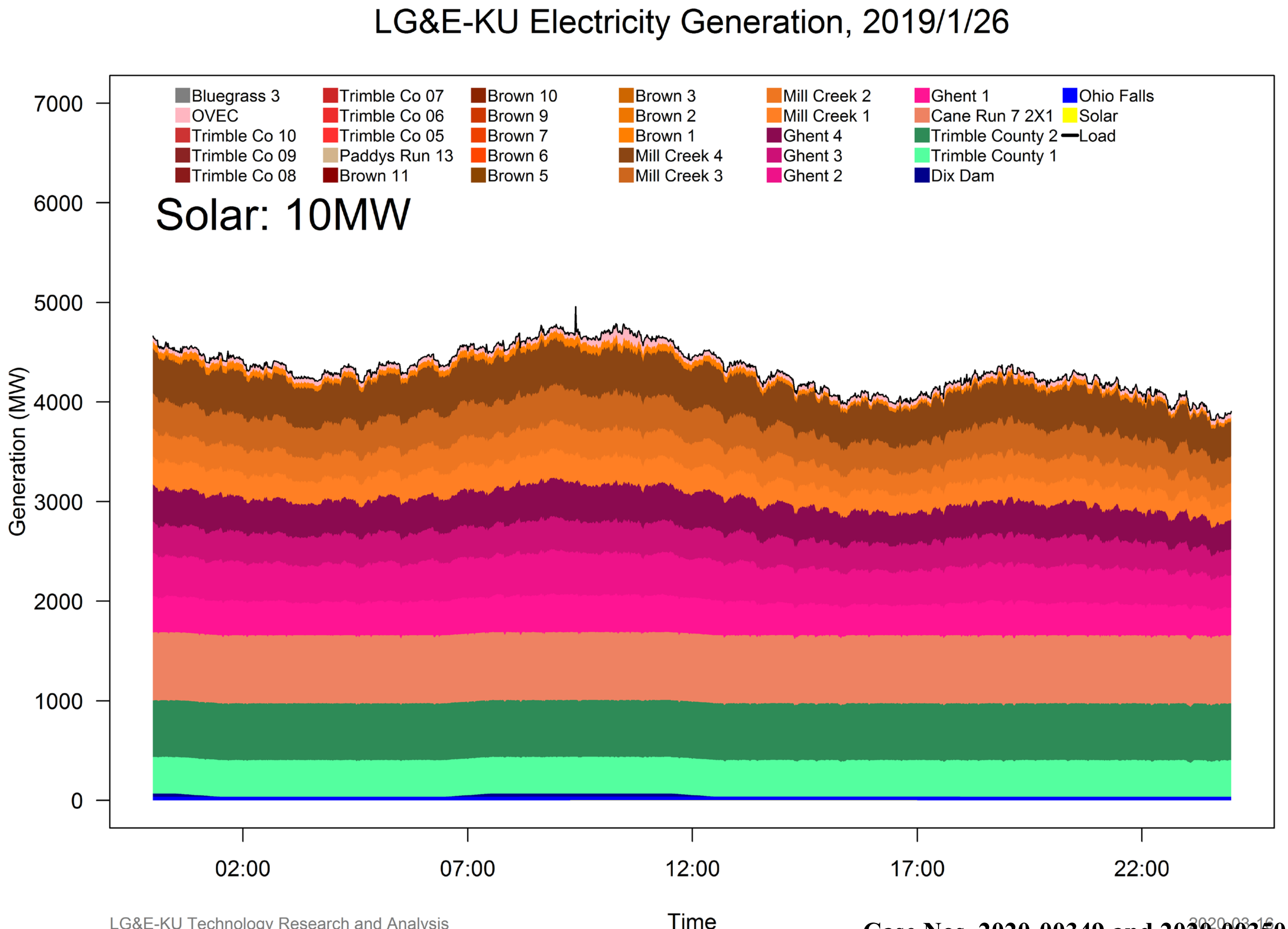
Example Solar Impact by Unit – January – 100 MW



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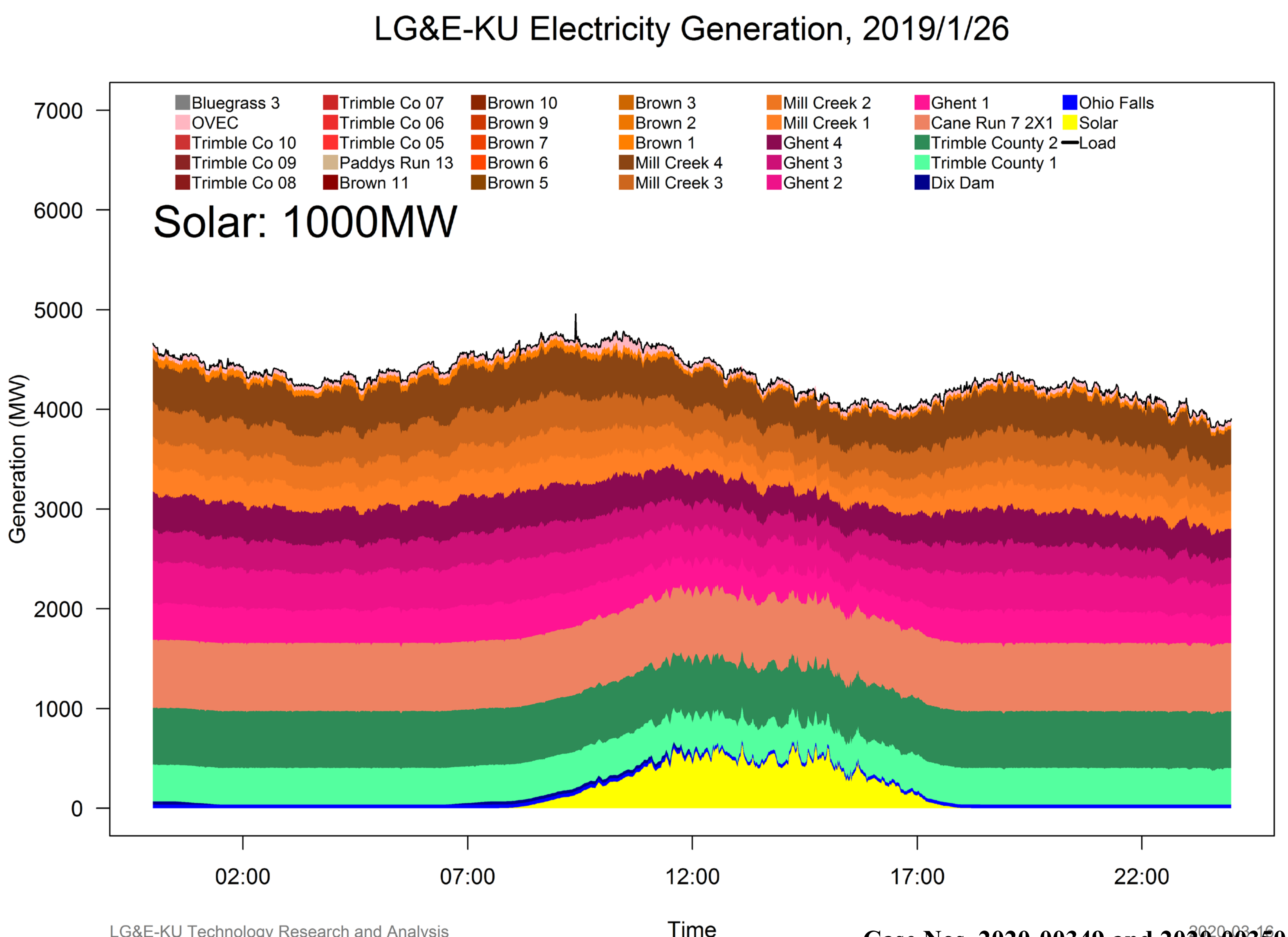
Example Solar Impact by Unit – January – 1000 MW



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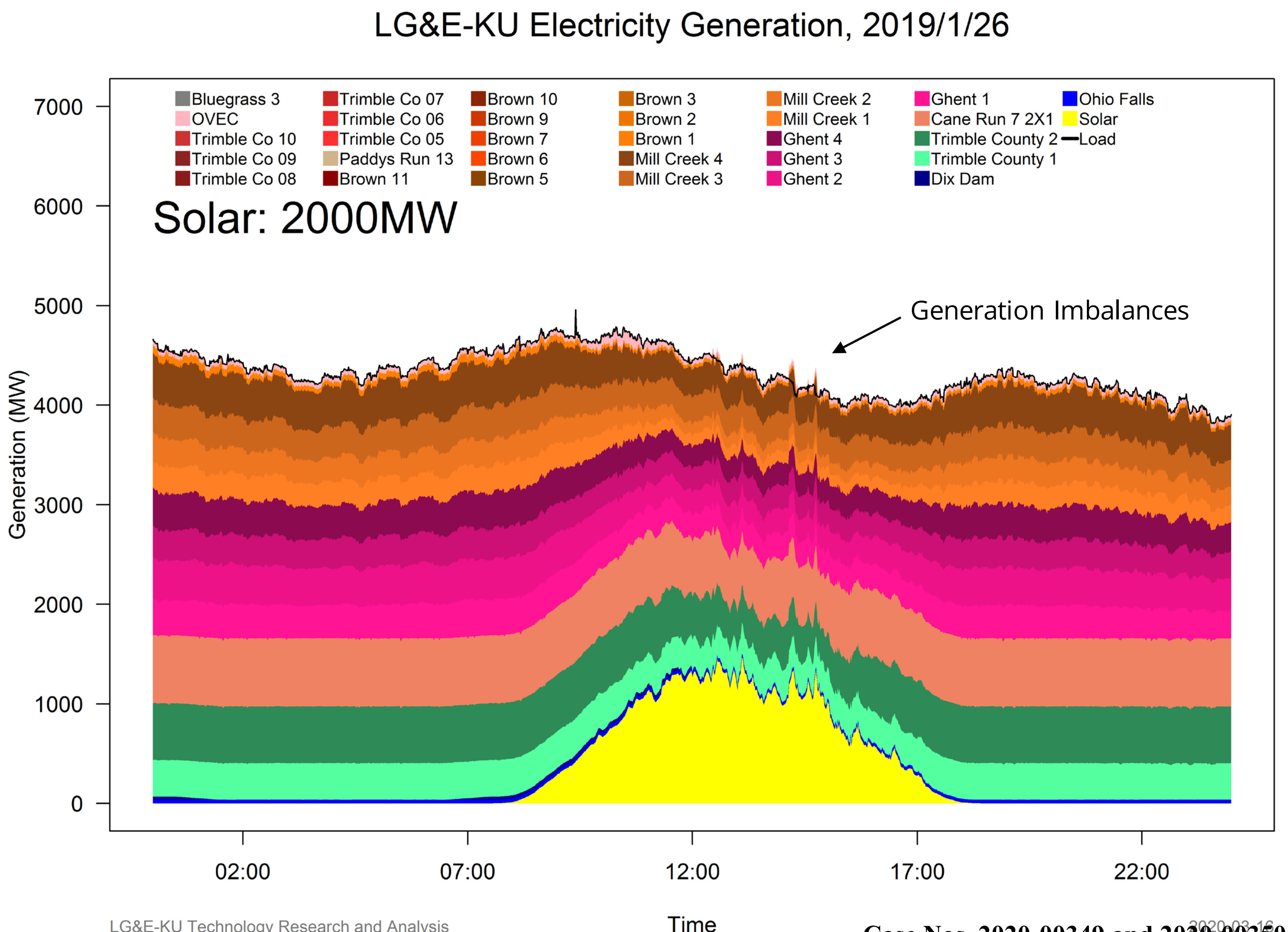
Example Solar Impact by Unit – January – 2000 MW



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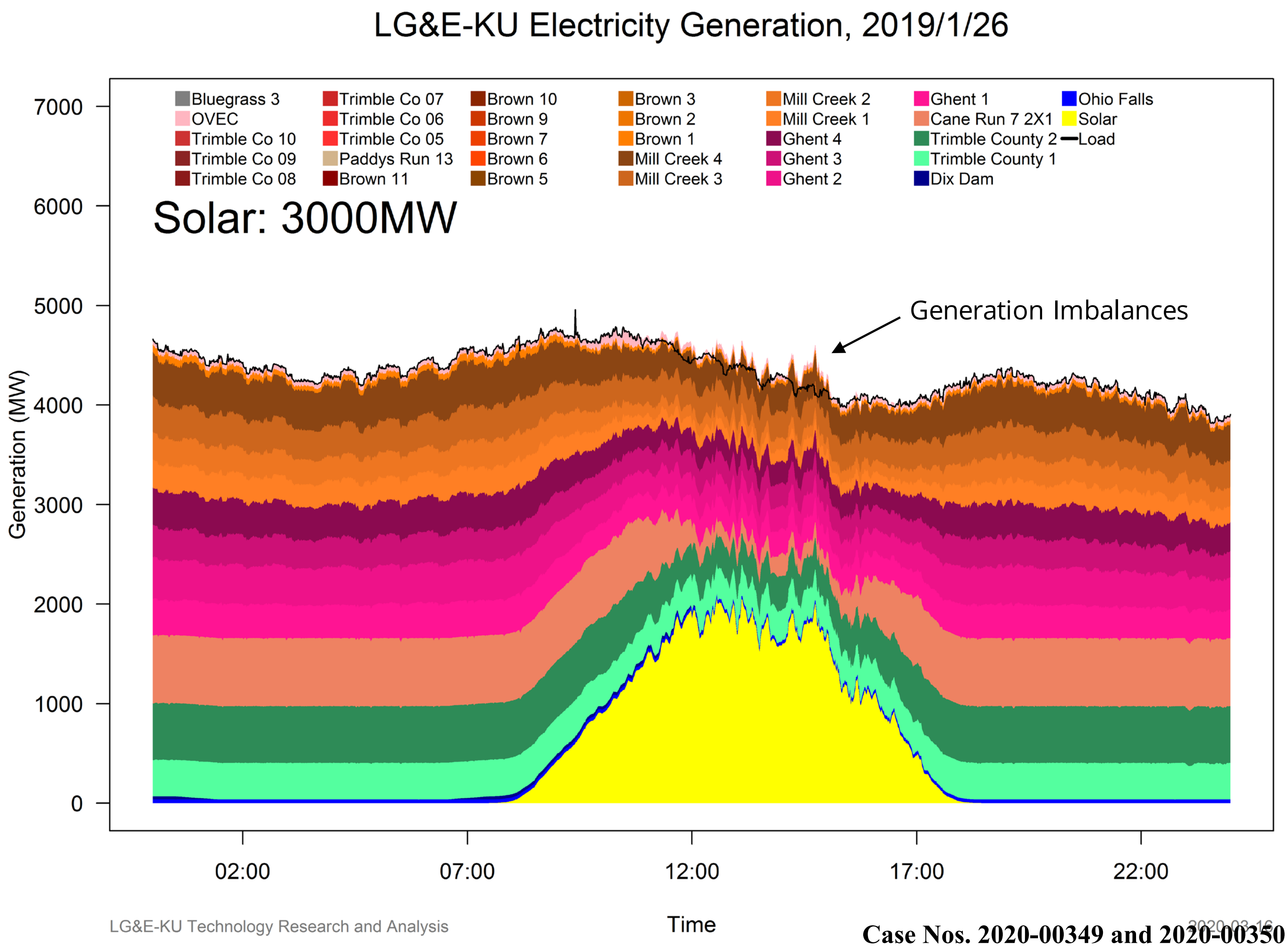
Example Solar Impact by Unit – January – 3000 MW



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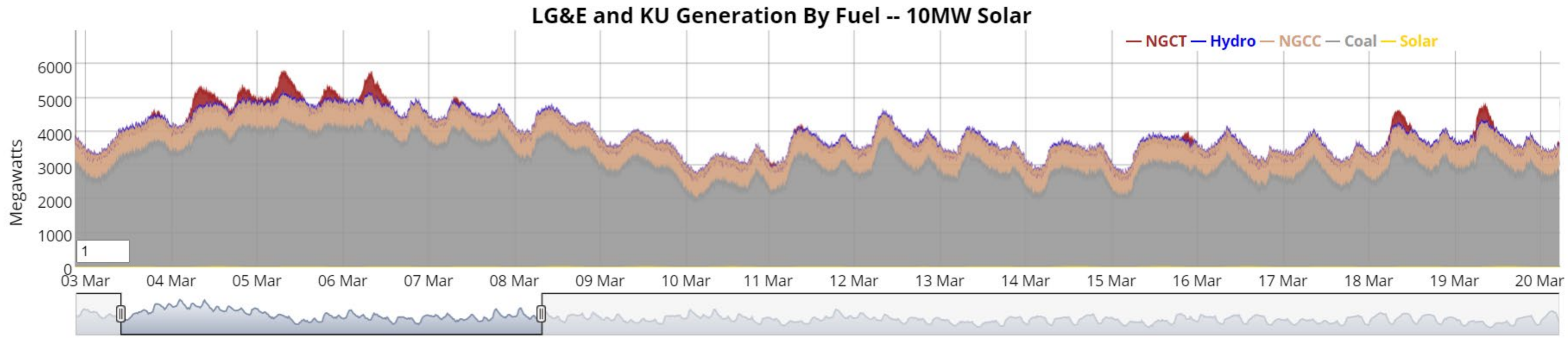
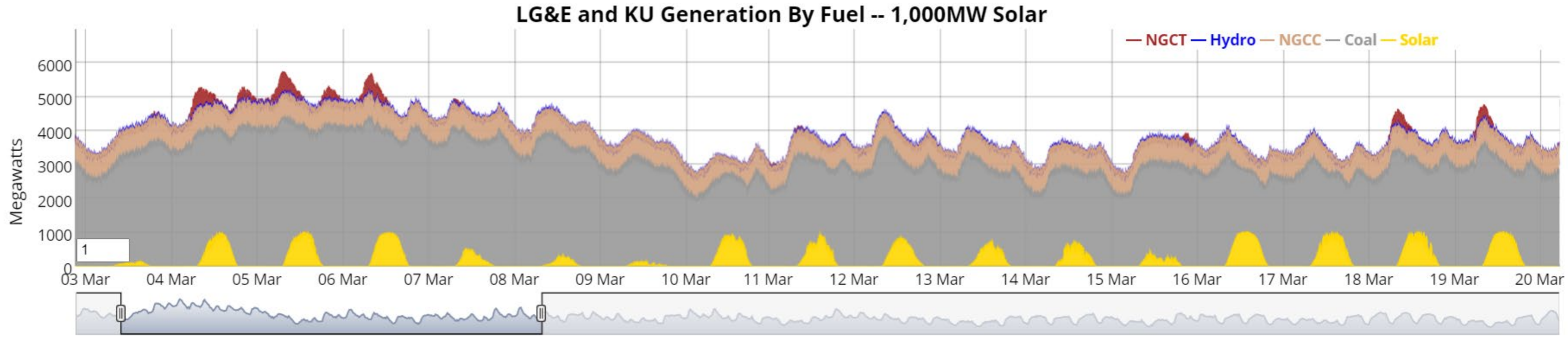
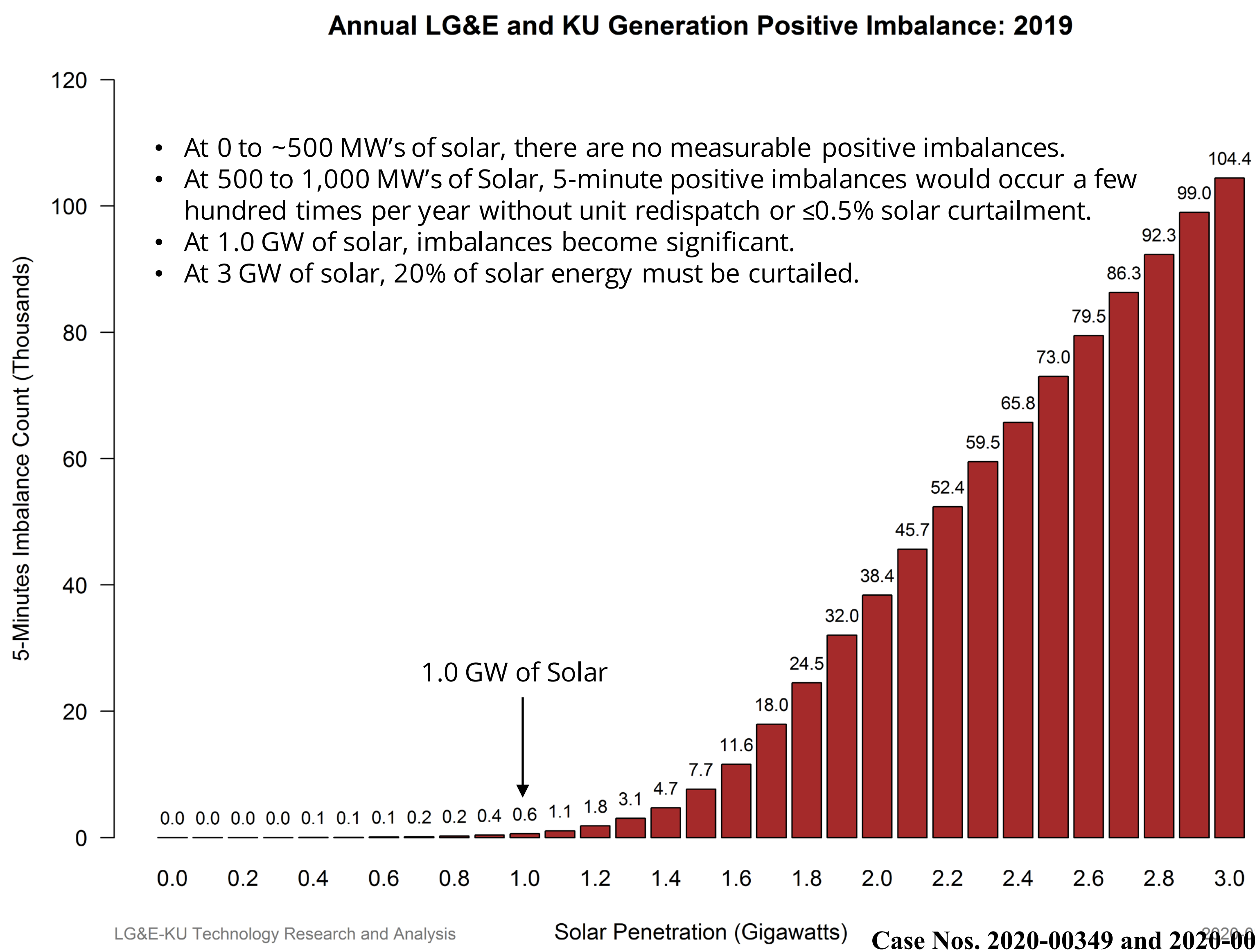
Interactive Simulation Results





Open Interactive Data: https://teams.sp.lgeenergy.int/sites/rd/Plots/LKE_Dispatch.html

Annual 5-Minute Imbalances by Solar Penetration



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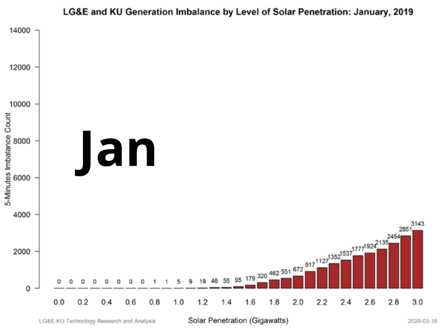
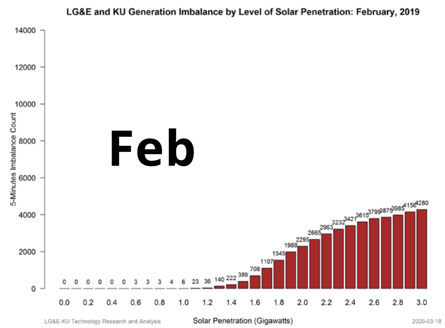
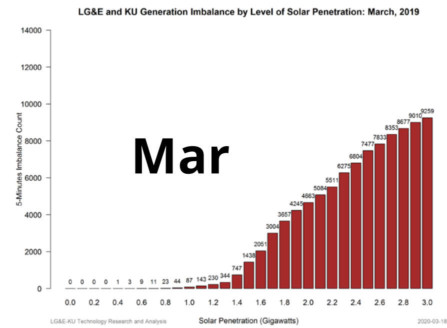
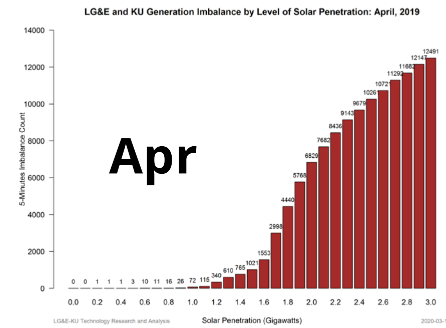
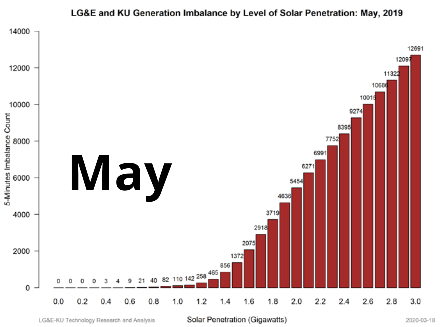
Monthly 5-Minute Imbalances by Solar Penetration

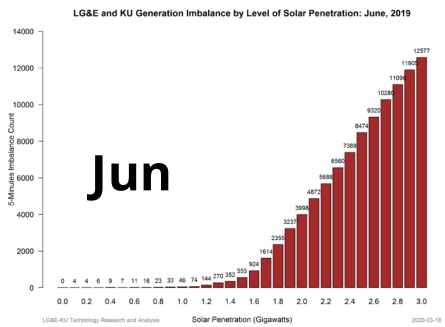


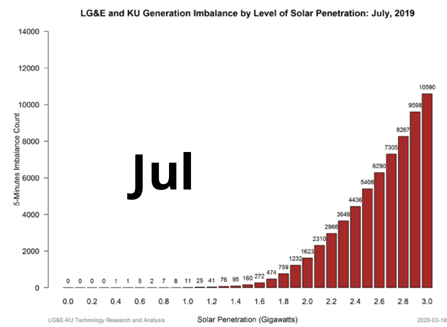


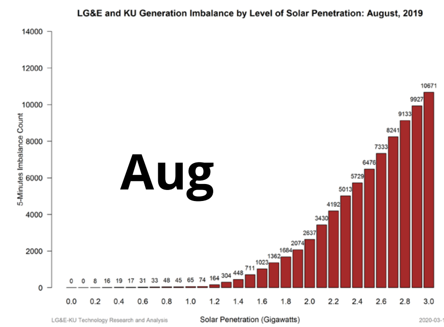


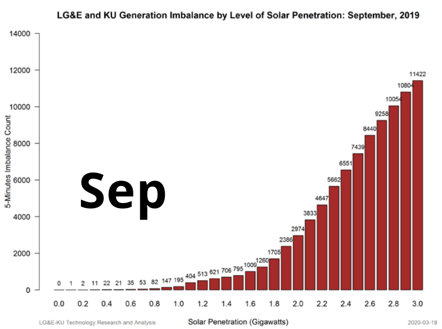


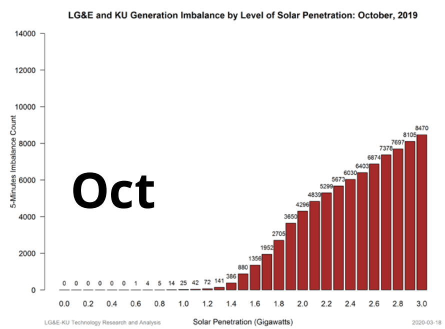


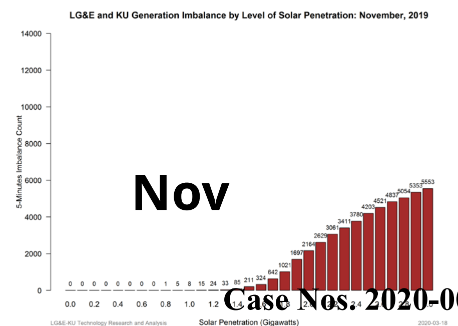


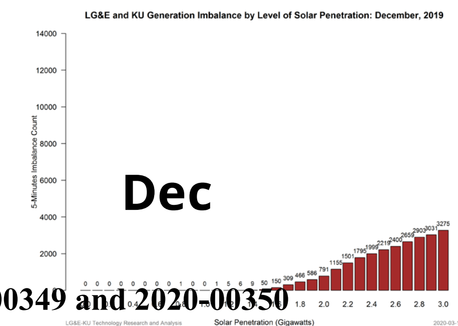












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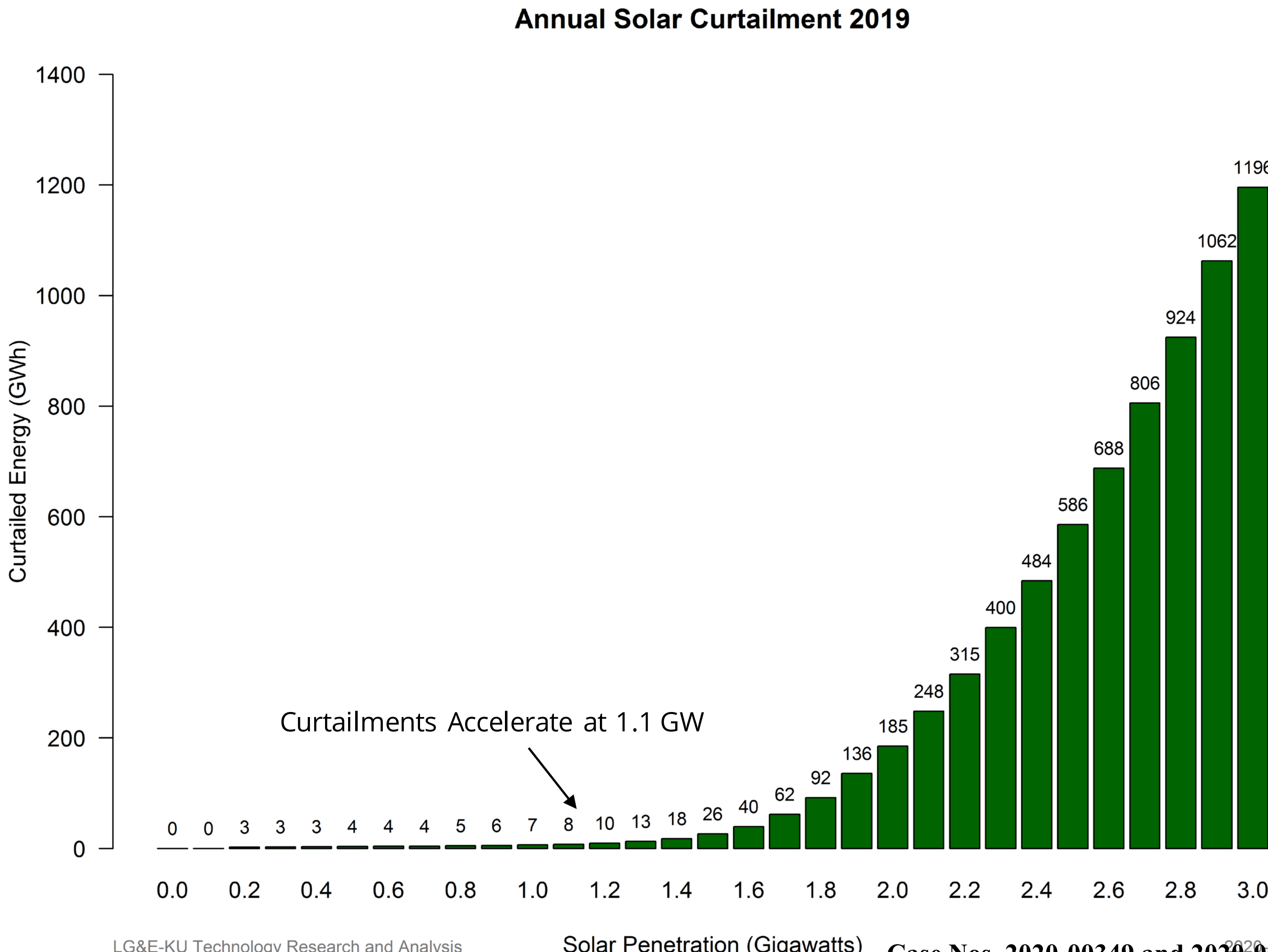
PPL companies

Annual Curtailed Energy by Solar Penetration



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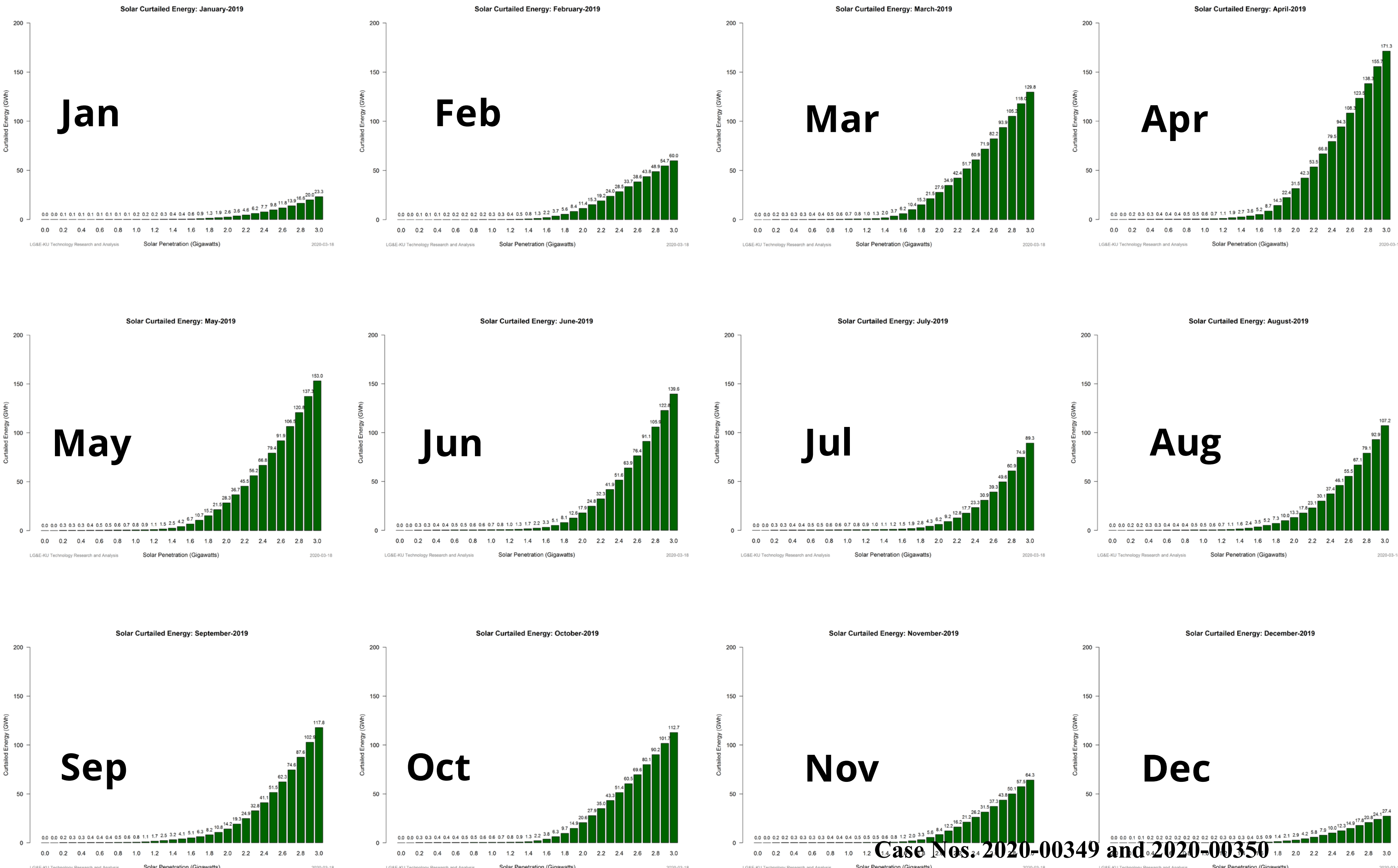
Annual Curtailed Energy by Solar Penetration

Solar Penetration (MW)	Curtailed Energy (MWh)	Percentage of Potential (%)
100	87	0.05
200	2,530	0.74
300	2,939	0.58
400	3,400	0.50
500	3,777	0.41
600	4,345	0.39
700	4,481	0.35
800	5,139	0.36
900	5,710	0.34
1000	6,752	0.36
1100	7,669	0.36
1200	9,717	0.42
1300	13,026	0.51
1400	18,095	0.66
1500	26,455	0.89

Solar Penetration (MW)	Curtailed Energy (MWh)	Percentage of Potential (%)
1600	39,934	1.26
1700	62,110	1.82
1800	92,319	2.55
1900	135,986	3.52
2000	185,401	4.56
2100	248,183	5.78
2200	315,415	7.02
2300	399,797	8.44
2400	484,317	9.80
2500	586,074	11.32
2600	688,023	12.78
2700	805,687	14.35
2800	924,405	15.87
2900	1,062,433	17.53
3000	1,195,771	19.08

Monthly Curtailed Energy by Solar Penetration



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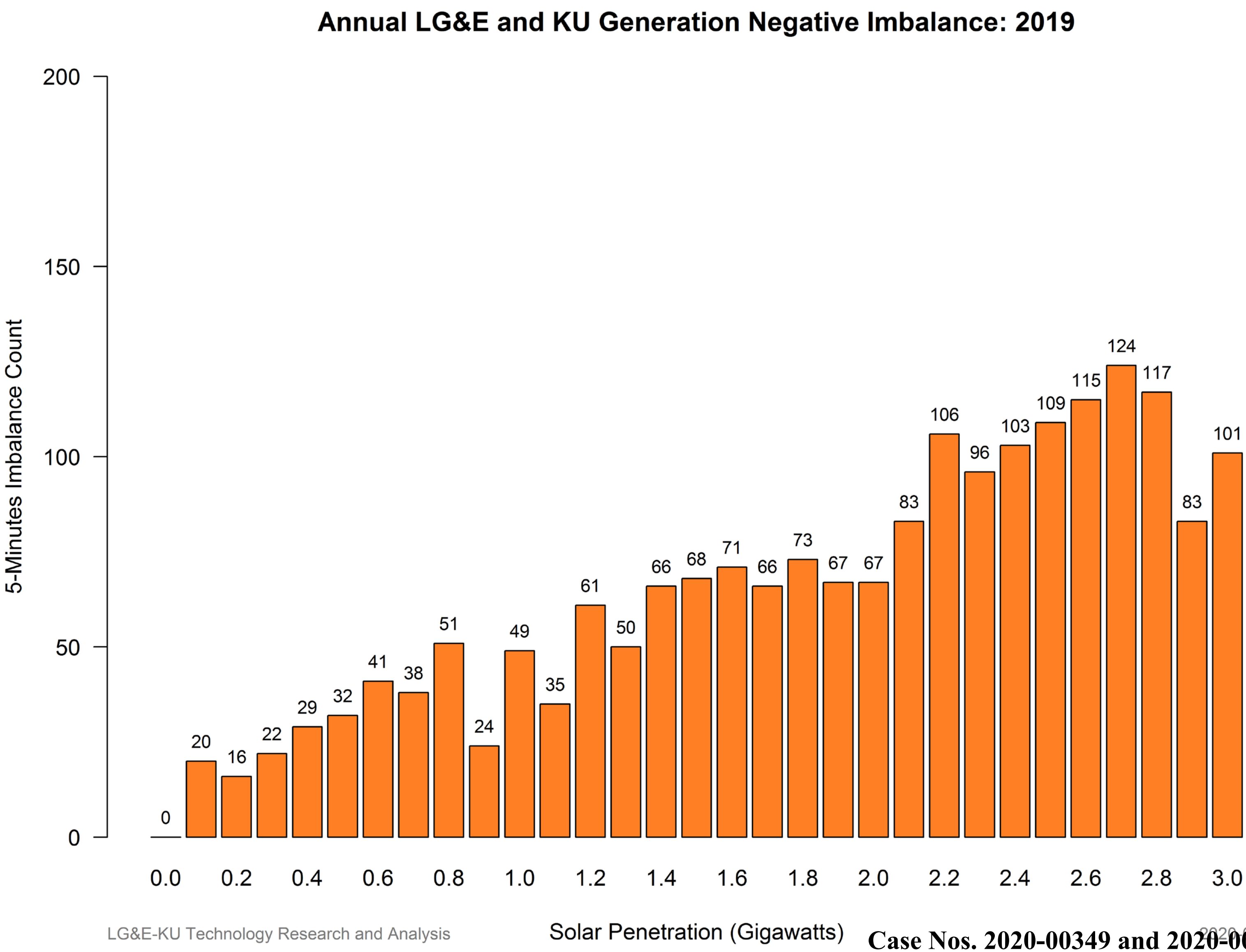
LG&E KU PPL companies

Annual 5-Minute Negative Imbalances



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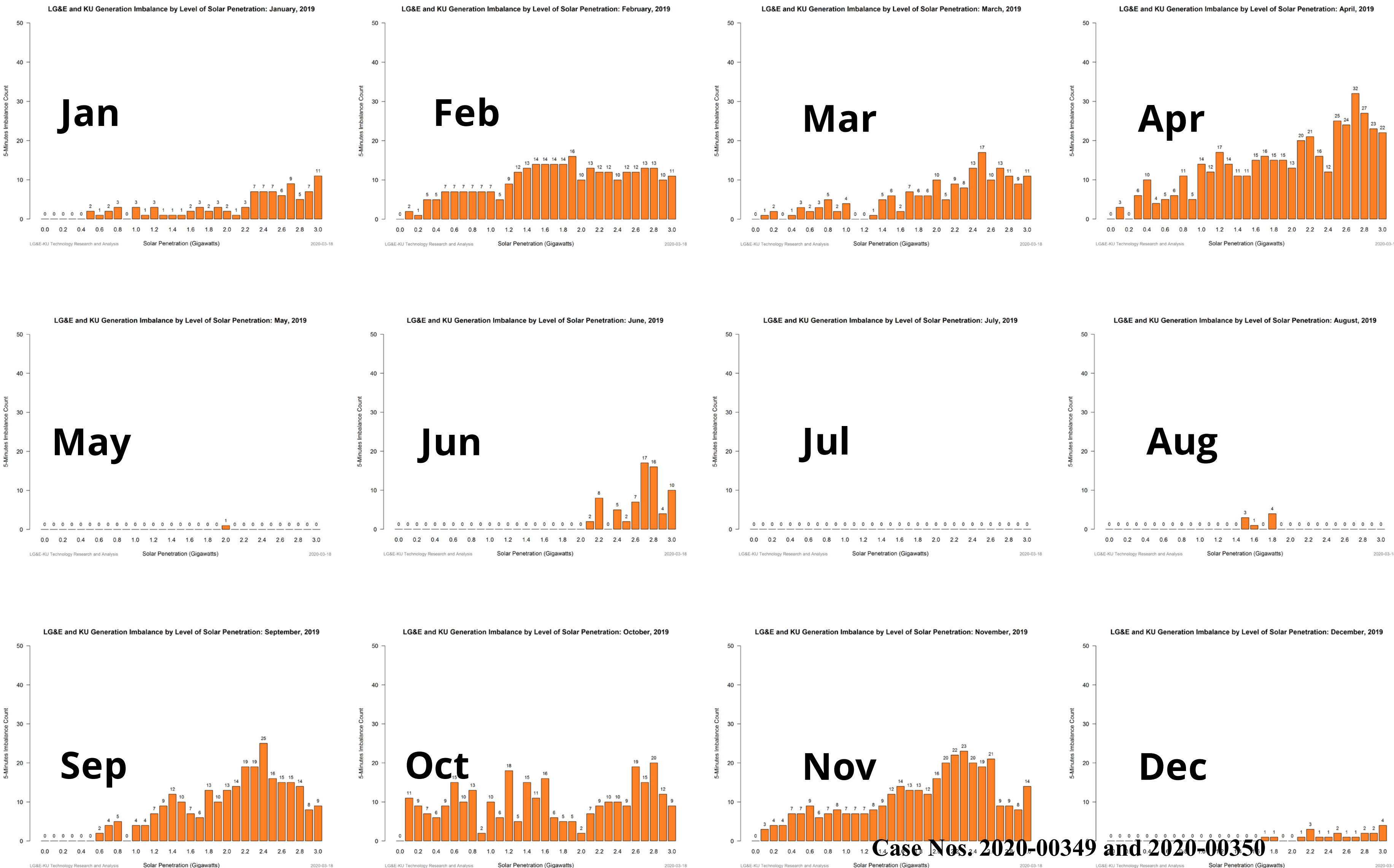
Monthly 5-Minute Negative Imbalances



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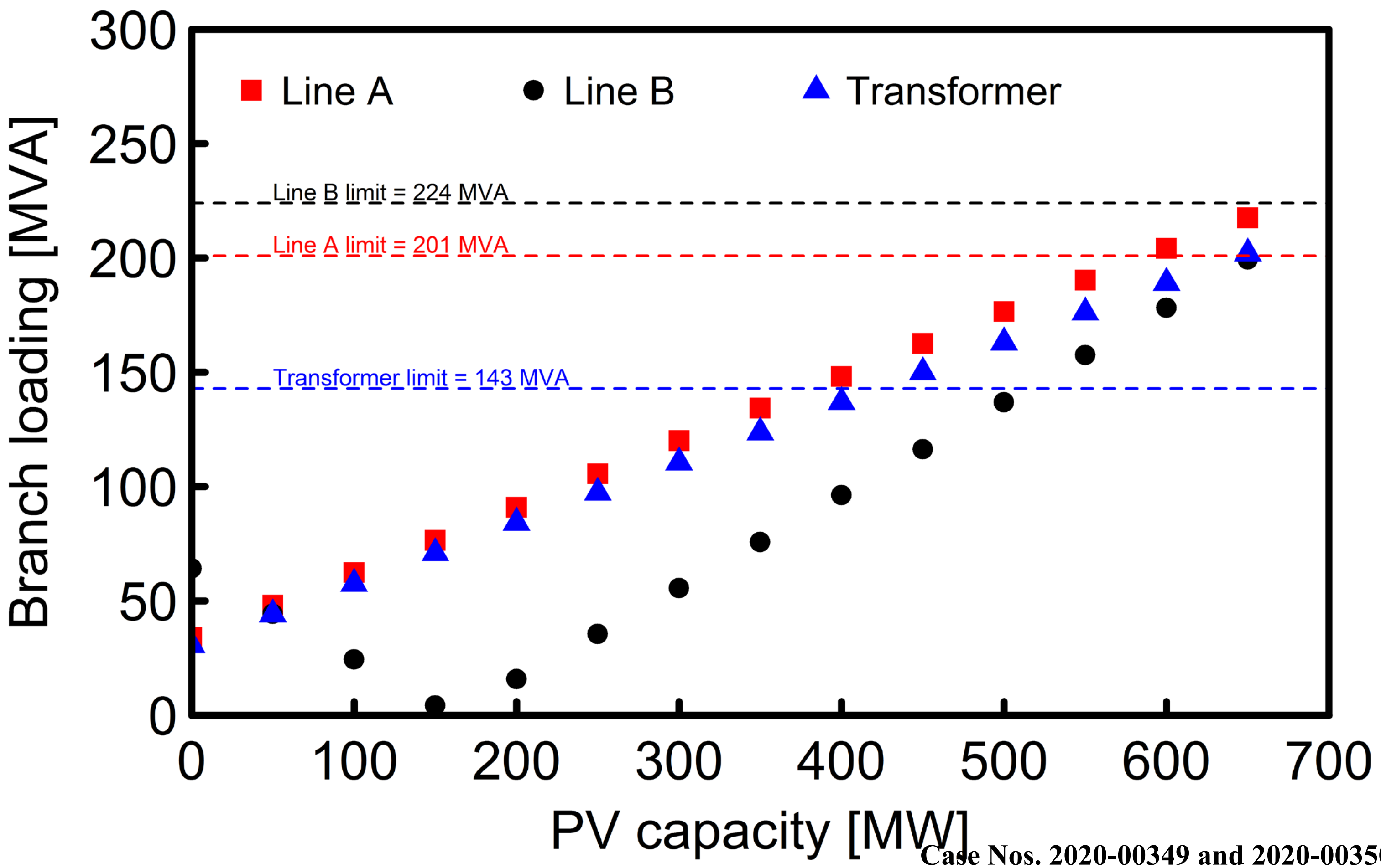
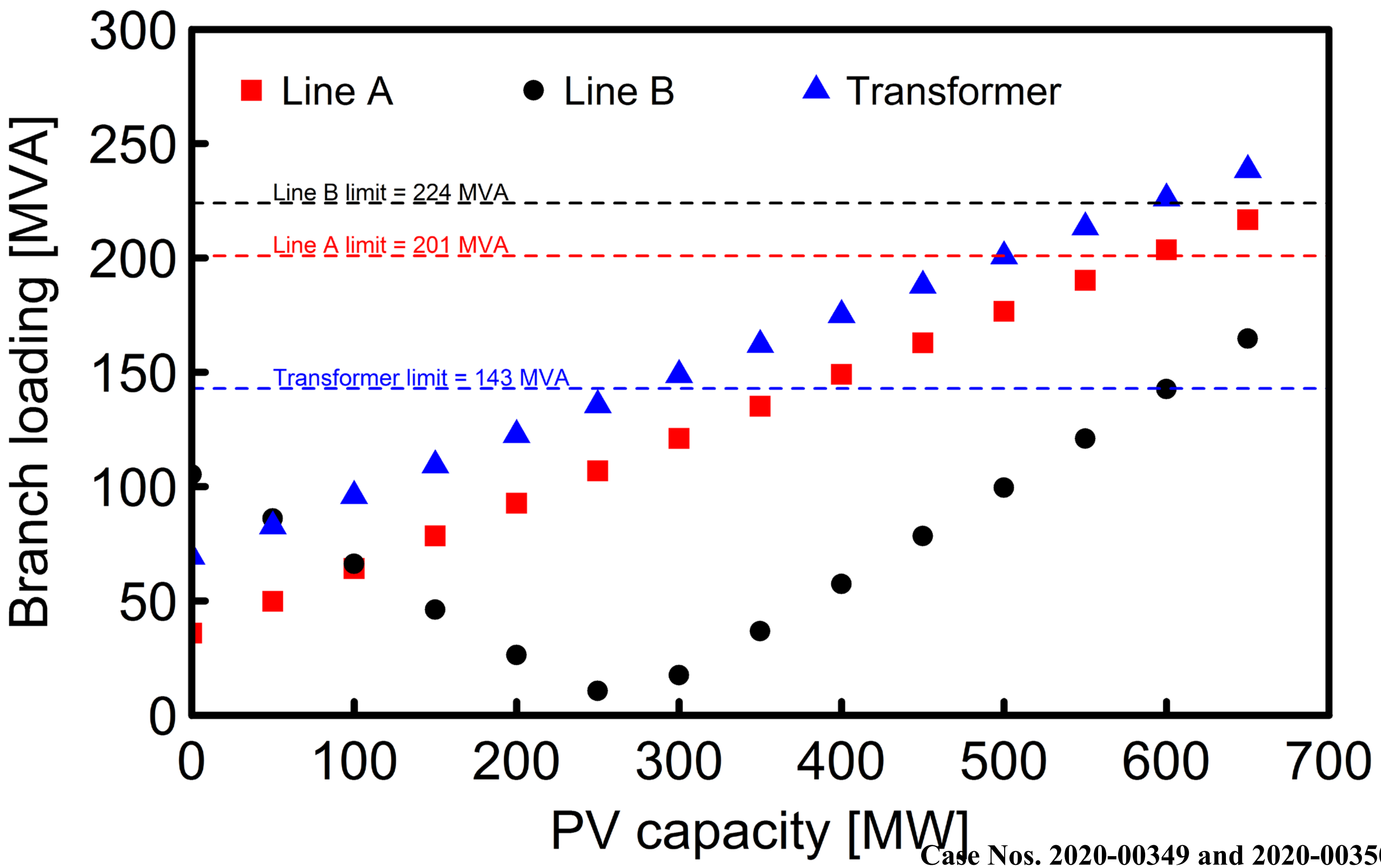
Transmission Impacts

Example Thermal Loading – Off Peak



Example Thermal Loading - Peak



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Methodology

Peer-Reviewed Methodology

Akeyo, Oluwaseun M., Aron Patrick, and Dan M. Ionel 2021. **"Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System"** *Energies* 14, no. 1: 169. https://doi.org/10.3390/en14010169

https://www.mdpi.com/1996-1073/14/1/169

energies

Article

Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System

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* Correspondence: dan.ionel@ieee.org

Abstract: Significant changes in conventional generator operation and transmission system planning will be required to accommodate increasing solar photovoltaic (PV) penetration. There is a limit to the maximum amount of solar that can be connected in a service area without the need for significant upgrades to the existing generation and transmission infrastructure. This study proposes a framework for analyzing the impact of increasing solar penetration on generation and transmission networks while considering the responses of conventional generators to changes in solar PV output power. Contrary to traditional approaches in which it is assumed that generation can always match demand, this framework employs a detailed minute-to-minute (M-M) dispatch model capable of capturing the impact of renewable intermittency and estimating the over- and under-generation dispatch scenarios due to solar volatility and surplus generation. The impact of high solar PV penetration was evaluated on a modified benchmark model, which includes generators with defined characteristics including unit ramp rates, heat rates, operation cost curves, and minimum and maximum generation limits. The PV hosting capacity, defined as the maximum solar PV penetration the system can support without substantial generation imbalances, transmission bus voltage, or thermal violation was estimated for the example transmission circuit considered. The results of the study indicate that increasing solar penetration may lead to a substantial increase in generation imbalances and the maximum solar PV system that can be connected to a transmission circuit varies based on the point of interconnection, load, and the connected generator specifications and responses.

Keywords: hosting capacity; photovoltaic; PSS/E; economic dispatch; voltage violations; thermal limits; PV penetration; solar

Citation: Akeyo, O.M.; Patrick, A.; Ionel, D.M. Study of Renewable Energy Penetration on a Benchmark Generation and Transmission System. *Energies* **2021**, *14*, 169. https://doi.org/10.3390/en14010169

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1. Introduction

Renewable energy resources are rapidly becoming an integral part of electricity generation portfolios around the world due to declining costs, government subsidies, and corporate sustainability goals. Large renewable installations on a transmission network may have potential impacts on the delivered power quality and reliability, including voltage and frequency variations, increased system losses, and higher wear of protection equipment [1]. Estimating the maximum hosting capacity of a transmission network may be used to determine the highest renewable penetration the system can handle without significant violations to the quality of the power delivered and the reliability of the grid.

Most recent literature has been focused on analyzing the impact of intermittent renewables on either generation or transmission systems only [2–5]. In [6], a methodology for estimating the solar PV hosting capacity based on steady-state circuit violations, without a detailed economic dispatch model was proposed. Typical dispatch models in the literature assume generation can always match load or set optimization constraints that are only acceptable for hourly dispatch models with relatively low load variations [7–9]. These hourly dispatch models may not be suitable for capturing the impact of PV systems for practical generation service areas, which record generation imbalance violations over duration as low as 15-min.

Furthermore, a substantial portion of literature has been focused on estimating the maximum PV hosting capacity for distributions systems and proposing network configurations that do not consider the contributions of conventional generators [10–13]. However, more than 60% of PV installations in the US are utility-scale setups typically connected to the transmission network [14]. Steady-state and transient analysis of transmission networks were presented in [6,15], but none of the works considered the variability of the connected loads or present a detailed economic dispatch to capture the responses of the conventional generators.

This research presents a framework for analyzing the impact of increasing PV penetration on both generation and transmission systems. Contrary to conventional approaches dispatching units with substantial intermittent renewable resources with hourly based dispatch models [7,16], this approach employs an M-M dispatch model capable of capturing the impact of large solar PV penetration and identifying minute-based periods of generation imbalance due to PV volatility and surplus power. The presented technique is also capable of analyzing the impact of increasing PV system penetration have on transmission circuits while considering the responses of conventional generators to changes in solar PV power.

The impact of increasing solar PV penetration was analyzed on a modified IEEE 12 bus system [17] with generators, including coal, natural gas combustion turbine (NGCT), natural gas combined cycle (NGCC), and a hydropower plant with practical unit specifications. This study uses generator models developed on data provided by LG&E and KU on operational units to simulate the responses of conventional generators to increasing solar PV penetration (Figure 1). Publicly available one-minute irradiance data for the 10 MW PV farm located at the utility's facility was used to model typical variation in solar irradiance [18]. The PV hosting capacity of the example generation and transmission network systems analyzed was estimated based on voltage, thermal, and generator dispatch violations.

Figure 1. The aerial view of the E.W. Brown generating station, which includes Kentucky's largest solar farm, hydropower plant, natural gas units, and coal fired power plants.

2. Proposed Minute-to-Minute Economic Dispatch Model

The real-time changes in load from minute to minute are relatively minimal due to aggregation. However, the volatility of the net demand on conventional thermal generators rises significantly with the increase in intermittent renewable energy penetration. Although it is nearly impossible to always match generation with demand for a service area, utilities are penalized by regulators for generation imbalances lasting longer than acceptable minutes [19,20]. Hence, conventional hourly dispatch models are not suitable to identify the generation imbalances and effectively capture the effect of solar PV intermittency on evaluated service area.

This approach employs a minute-based dispatch since the solar PV power variability due to cloud cover is expected to reduce as the plant capacity and footprint increases. The proposed minute-to-minute dispatch model in this study was developed for the IEEE 12 bus test system illustrated in Figure 2. The system which consists of four generating units was modified based on the specifications presented in Table 1 and subjected to realistic load variations for an example day in the Fall season. The efficiency of thermal generating units in terms of their heat rate vary with percentage output for different types of units (Figure 3). In this approach, the heat rates for thermal units are described as follows:

$$Q_g^R(P_g) = \frac{Q_g^{in}(P_g)}{P_g} \approx a_g P_g^2 + b_g P_g + c_g, \quad (1)$$

where $Q_g^R(P_g)$ represents the heat rate for unit g with output power P_g; Q_g^{in} the heat requirement; and a_g, b_g, c_g are the heat rate co-efficient of the generator. Therefore, the operating cost for each unit may be expressed as:

$$C_g(P_g) = Q_g^R(P_g) \cdot F_g + Z_g, \quad (2)$$

where C_g is the running cost for generator g; F_g, the fuel cost and Z_g, the fixed cost constant, which includes maintenance and emission reduction costs. Therefore, the proposed M-M dispatch model can estimate the running cost of the thermal units for specified output level within its limits of operation (Figure 4).

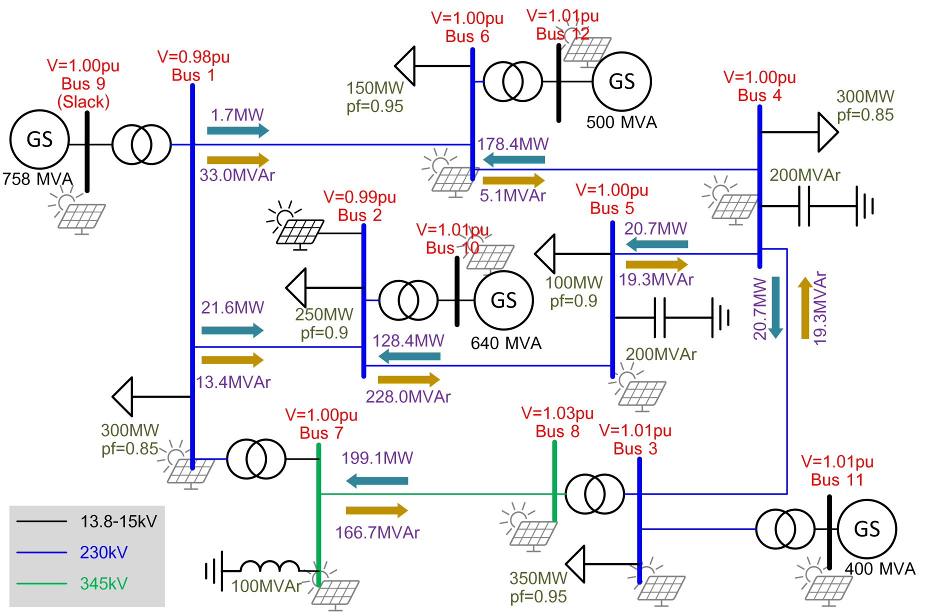

Figure 2. Single line diagram for the modified benchmark network with PV plant connected to bus 2 and values corresponding to approximately 65% (1450 MW) load level. The transmission circuit was completely assessed for PV connection at any of its buses.

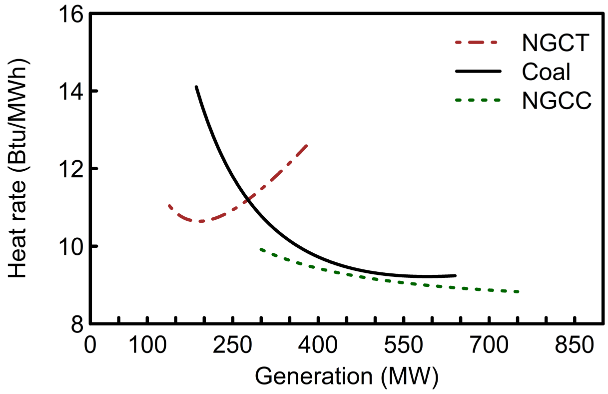

Figure 3. Example heat rate curve for natural gas combustion turbine (NGCT), coal, and natural gas combined cycle (NGCC) thermal generators considered in this study.

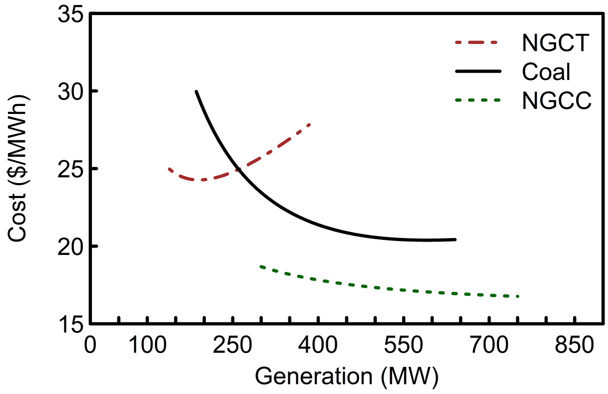

Figure 4. The operation cost in $/MWh including the fuel and auxiliary costs for the thermal units considered. The cost rate in $/h can be calculated as a product of the operation cost and the generation.

Table 1. Specifications for the generating units in the modified IEEE 12 bus test case studied.

Bus No.	Type	Rating (MW)	Min Gen (MW)	Ramp (MW/min)	Heat Rate Co-Eff. a (10^{-3})	b	c	Fuel ($/MMBtu)	Aux ($/MWh)
9	NGCC	750	368	10	0.4	7.7	630	1.76	1.23
10	Coal	640	288	7	5.5	2.7	1935	1.96	1.79
11	NGCT	384	203	9	20.7	2.7	753	1.76	5.54
12	Hydro	474	-	-	-	-	-	-	-

For a practical economic dispatch problem, the objective is to minimize cost and generation imbalance such that the cheapest combination of generators are regulated to meet demand. Therefore, the economic dispatch model objective can be expressed as:

$$\min \begin{cases} C_T = \sum_{g=1}^{G} C_g(P_g) \\ \epsilon = |P_T - L_c| \end{cases}, \tag{3}$$

where

$$P_T = P_1 + P_2 + \ldots + P_G, \tag{4}$$

C_T, represents the total operating cost for all units considered; P_T, the combined generator output; L_c, the combined service area load; and G the total number of operational units including the PV plant. Following theoretical developments in [21], the minimum C_T for each instance without considering generator constraints and transmission losses occurs when the total differential cost is zero and may be described as follows:

$$\partial C_T = \frac{\partial C_T}{\partial P_1} dP_1 + \frac{\partial C_T}{\partial P_2} dP_2 + \ldots + \frac{\partial C_T}{\partial P_G} dP_G = 0. \quad (5)$$

However, due to generator constraints including ramp-rate limitation of units the result from (5) may fall outside operation range.

Contrary to conventional approaches, this approach recognizes the practical limitations of generator units. The constraints for the considered thermal units are as follows:

$$P_g^{min}(t) \le P_g(t) \le P_g^{max}(t) \quad (6)$$

$$P_g^{min}(t) = \max\left[\underline{P_g}, \quad P_g(t-\Delta t) - \Delta t \cdot R_g^{down}\right] \quad (7)$$

$$P_g^{max}(t) = \min\left[\overline{P_g}, \quad P_g(t-\Delta t) + \Delta t \cdot R_g^{up}\right] \quad (8)$$

where $P_g^{max}(t)$ and $P_g^{min}(t)$ are the maximum and minimum output power for unit g, respectively; $\overline{P_g}$ and $\underline{P_g}$ are the specified maximum and minimum generator operation limits; R_g^{up} and R_g^{down}, the generator rising and falling ramp rates, respectively.

This study is focused on the impact of increasing PV penetration on an example system with five generators. The proposed framework economic dispatch model employs a multi-objective genetic algorithm (GA) to minimize C_T and ϵ for the three thermal units in the system and the "non-dispatchable" units (PV and hydro) output are set based on reference values from practical modules. The solar plant reference power module was developed based on measured irradiance data retrieved from an operational solar PV farm. The PV output power is expressed as follows:

$$P_{pv} = \frac{\gamma}{1000} \times \eta \times \overline{P_{pv}}, \quad (9)$$

where P_{pv} is the PV plant power, γ is solar irradiance in W/m^2; η is the inverter efficiency, and $\overline{P_{pv}}$ is the rated capacity. The algorithm goes through multiple combinations of generator set points limited by $P_g^{min}(t)$ and $P_g^{max}(t)$ for each unit to establish a Pareto front. Since the primary objective of the utilities is to meet demand, the design with the least amount of imbalance is selected for the simulation time-step (Figure 5).

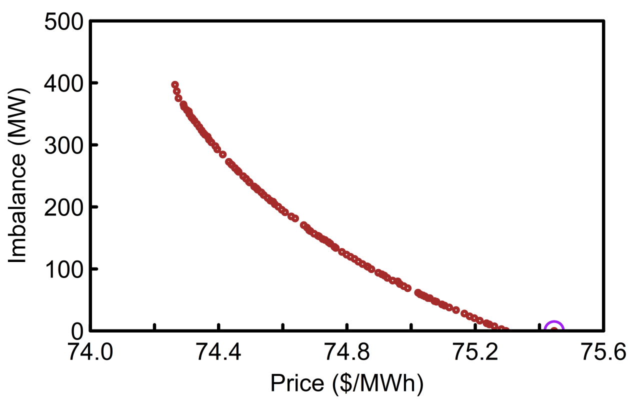

Figure 5. The multi-objective optimization Pareto front for example minute. The selected design is the one with the minimum imbalance for every case.

To identify periods of over- and under-generation, the proposed M-M dispatch model assumes the generators in the transmission circuit are solely responsible for meeting demand for the concerned service area without need for off system sales and electricity power trading. Factors such as unit commitment and outage are beyond the scope of this study. Therefore, all units are assumed to be available and committed throughout the example day.

3. Conventional Generators Response to Increasing PV Penetration

Increasing solar penetration can make it more challenging for grid operators to balance generation with load in real time, since generating units are committed based on load forecast and level of uncertainty. In this study, the integrated PV farms are operated in "must-take" modes, in which thermal units are turned down to accommodate solar PV penetration. The relatively high power variation of the PV plant for the example day considered leads to significant generation imbalance during periods when the operating units cannot ramp up or down fast enough for meet demand.

Due to the minimum generation limit of the available thermal unit, a significant level of over-generation may be observed at hours between 9:00 and 13:00, when the generators could not ramp down further to accommodate the increasing PV penetration (Figure 6). In addition to the rest time required to restart thermal units, a significant amount of time, up to 24 h for some coal units is required to restart start them which makes it extremely challenging to turn off the units at midday and restart them for evening peak [22].

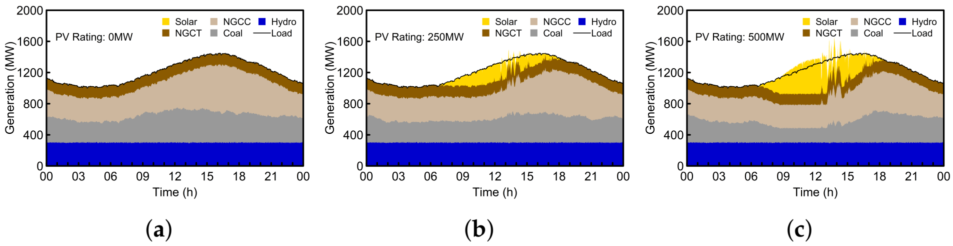

Figure 6. Minute-to-minute (M-M) unit economic dispatch highlighting the impact of increasing PV penetration on an example generation portfolio. The results indicate that large PV penetrations may lead to both over- and under-generation scenarios where combined power from units cannot match demand. The presented analysis include (**a**) no PV, (**b**) 250 MW PV, and (**c**) 500 MW PV penetration case studies.

The current solar PV regulatory standards may not be sufficient for managing high intermittent renewable sources penetration and new standards will be required to ensure grid stability in a future grid [23,24]. Furthermore, the penetration of distributed renewable sources such as rooftop solar will lead to substantial changes in the apparent load on the transmission network that may call for additional regulations. In this study, a generation violation or imbalance count is recorded when the area control error, ACE, exceeds ±20 MW for defined consecutive minutes. The ACE is expressed as:

$$ACE = (T_m - T_s) + \beta_f(f - f_s), \tag{10}$$

where T_m and T_s are the measured and scheduled tie line lows, f and f_s, the measured and scheduled frequency, and β_f the frequency bias constant for the area. Frequency variation due to generation imbalance is beyond the scope of this study, therefore it was assumed that $f = f_s$, and T_s is always equal to zero. Hence, for this analysis (10) can be re-written as:

$$ACE = T_m = P_T - L_c. \tag{11}$$

The over- and under-generation imbalance count for the example day was evaluated for increasing PV penetration. A significant level of over-generation can be observed at solar PV penetration levels exceeding 400 MW (Figure 7). This is mainly due to the inability of the available units to operate at values below their minimum generation limits during periods of surplus solar generation. For the example day analyzed, there was no under-generation violation lasting more than 15 consecutive minutes (Figure 8). However, significant under-generation violation counts for 5 and 10 consecutive minutes, which was relatively constant for PV penetration above 350 MW was recorded. These violations are primarily due to the intermittent behavior of the PV systems and generating units not being able to ramp fast enough to supply deficit power due to sudden shading of the solar panels.

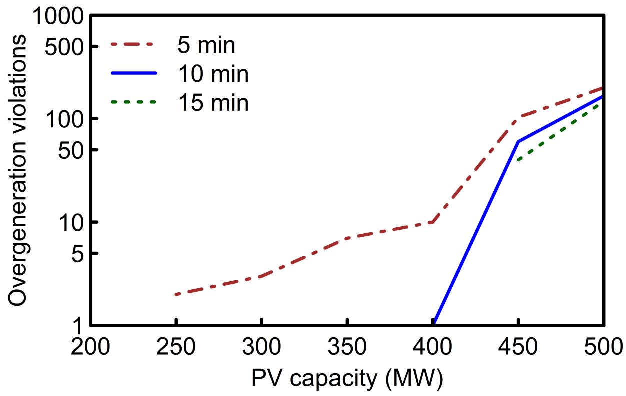

Figure 7. Example day over-generation violation count. In this approach a violation count is recorded when the dispatch imbalance exceeds 20 MW over defined consecutive minutes (5, 10 and 15).

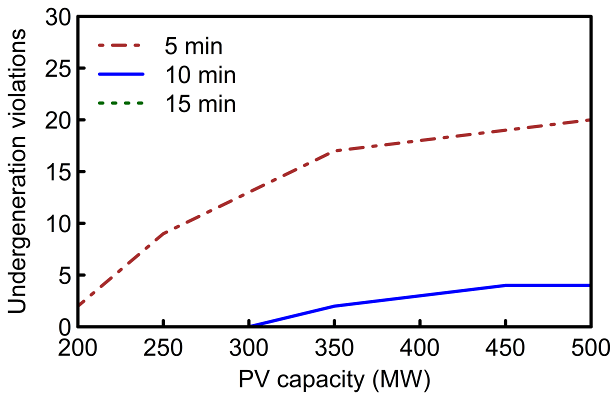

Figure 8. Under-generation violation count at increasing PV penetration rate. Under-generation occurs when PV becomes suddenly shaded and thermal units cannot ramp up fast enough to supply deficit power.

Solar power curtailment can be an effective tool for managing over-generation, in which the solar PV plant output may be held back when there is insufficient demand to consume production. This study examined how much curtailment will be required to address solar over-generation for the presented generator portfolio over the example day (Figure 9). An exponential increase in the curtailed PV energy to avoid over-generation violations was recorded, with rapid increase in curtailment for PV capacity above 400 MW. Due to the substantial PV energy curtailed, over 2% reduction in PV capacity factor was reported at 500 MW penetration level (Figure 10).

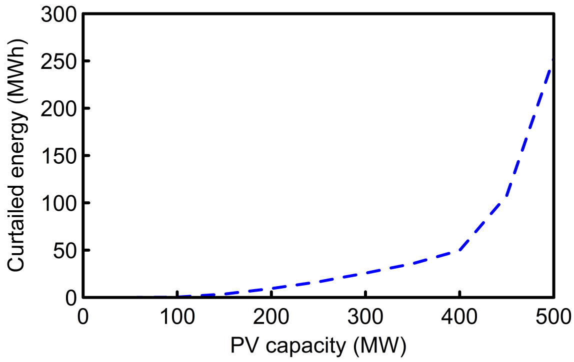

Figure 9. Curtailed energy solar energy for example day. In order to limit over-generation, an exponential increase in the total solar PV power curtailed can be observed.

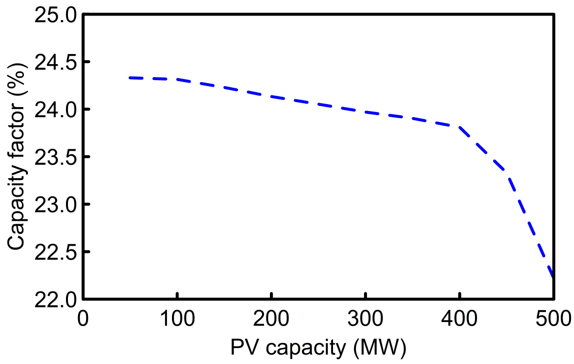

Figure 10. PV plant capacity factor based on penetration. Capacity factor can be observed to reduce with increase in curtailed power.

Increase in solar PV penetration is expected to lead to significant reduction in running cost without considering the capital cost for the PV system. It is, however, important to recognize that PV penetration may lead to more aggressive usage of fast ramping units such as NGCTs, which are typically the most expensive units in generation portfolios. This study evaluated the cost savings for the example day due to increase in PV penetration. A somewhat steady increase in cost savings was reported for solar PV penetration above 80 MW (Figure 11). However, due to generator commitment and increased operation of the NGCT unit for managing the solar PV variation over the example day, no cost savings was recorded for solar PV penetration below 80 MW.

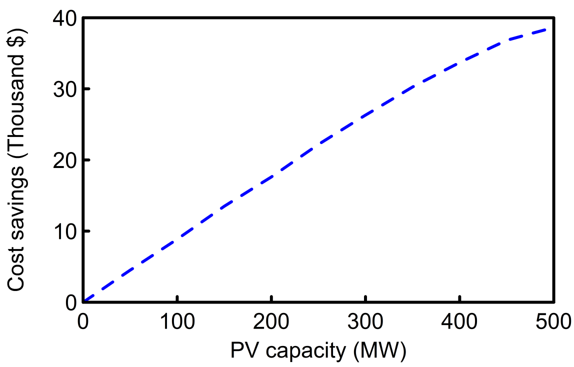

Figure 11. Operation cost saving due to increase in PV penetration. For the example day considered, an increase in operation cost was observed for PV penetrations below 500 MW due to operation of inefficient units to meet demand.

4. Modified Benchmark Transmission Network

The modified benchmark transmission system analyzed in this work represents a small islanded power system network with 12 buses and four generating units (Figure 2). This modified transmission network is based on the generic 12-bus test system developed for wind power integration studies presented in [17]. The transmission network base case was developed in PSSE with a single transmission line connecting buses 3 and 4, as opposed to the parallel cables in the initial setup.

At steady-state without renewable integration, the transmission network total system load is approximately 65% of the total generation capacity. The bus voltage voltages vary between 0.98 pu to 1.03 pu. In this example, each of the transmission lines is rated for a maximum of 250 MVA power flow except for the transmission lines connecting buses 7 to 8 and 3 to 4, which are rated to 500 MVA. At 65% load level without renewable integration, the maximum loading for any of the transmission lines is 71%, which is the power flow between buses 6 and 4.

Solar PV penetration have the maximum impact on generation during periods when load is relatively low. For transmission networks, maximum PV impact is observed during peak periods, when load is rather high and transmission lines are near saturation. In this approach, the transmission network was evaluated for the analyzed example day peak demand and the generating units were dispatched accordingly with respect to minimum operating cost and solar PV penetration.

The benchmark model was further modified to enable renewable system integration, such that a solar PV farm may be connected to either of its 12 buses. In order to connect the PV plant to a selected bus, an additional transformer is introduced to connect the PV plant terminal to the corresponding bus. Based on typical regulatory requirements, the PV plant is configured to be capable of operating at 0.95 power factor to support scheduled grid voltage at the point of interconnection (POI) [25].

5. Proposed Framework for Network PV Hosting Capacity

The PV hosting capacity for a transmission network is defined as the maximum solar PV capacity that may be connected to the system without significant upgrades to its circuit to ensure steady operation. The maximum hosting capacity of a transmission circuit depends on multiple factors including the bus voltage variation, thermal limits of the transmission lines, frequency variation, fault currents as well as regulated factors such as total harmonic distortion and grid codes. This study focuses on the maximum PV capacity that may be connected to any one of the buses in the example transmission network without violating the bus voltages or the thermal limits of the circuit branches.

The proposed framework established as a combination of modules developed in Python and transmission case studies in PSSE, may be employed to estimate the hosting capacity for a defined transmission network. Opposed to conventional approaches, this framework employs a practical and detailed economic dispatch model, which defines the output power of all available generating units based on combined running cost. This dispatch model also respects generator minimum power limit and ensures units are set to values within their operation limits. Hence, the combination of units that meet load at the least cost are dispatched for each case study analyzed.

The framework allows the user to define the potential buses for PV connections, the range and maximum PV capacity to be analyzed, and the load levels to be considered. The simulation study is initialized with for the based case without solar PV penetration and the case study is evaluated. The combined load for the analyzed instance is then distributed to all the load buses at a ratio and power factor identical to the base case. The transmission network is then modified such that the minimum PV capacity to be evaluated is connected to the first candidate bus to be analyzed. All the available generators are re-dispatched to accommodate the increase in PV penetration.

The modified circuit is solved in PSSE, and the connected PV rating is increased if the solution converges. The framework keeps increasing the connected PV rating at predefined steps until solution failure or maximum PV rating to be analyzed, after which it resets to a minimum PV rating for the next bus or load level. The simulation comes to an end after the combinations of all PV ratings, connection buses and load levels have been exhaustively tested and results extracted (Figure 12). Based on the criteria defined for the system circuit, the collected results are therefore analyzed to determine the system's maximum hosting capacity.

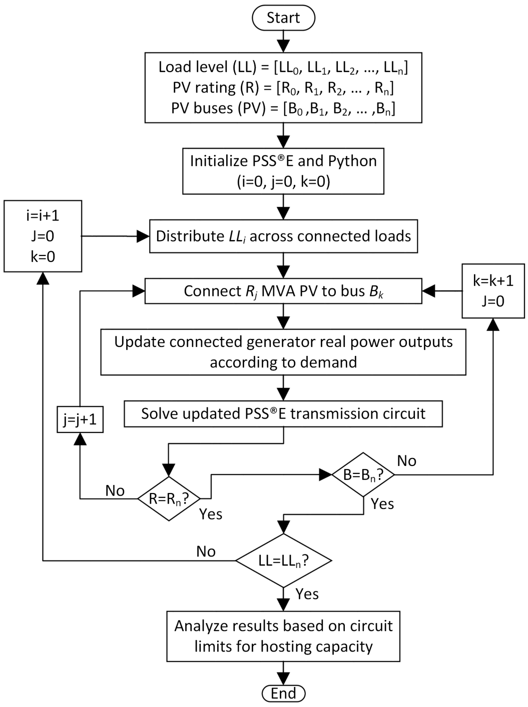

Figure 12. Operational flow chart for the proposed framework for estimating the hosting capacity on a transmission network. The steady-state impact for increasing solar PV capacity at different POI was evaluated to estimate the maximum PV hosting capacity for the network.

6. Transmission Network Response to Increasing PV Capacity

The proposed framework was employed to estimate the PV hosting capacity for the modified IEEE 12 transmission network. The PV hosting capacity was evaluated based on the bus voltage responses of the network, thermal loading and circuit solution convergence. The network was evaluated at 1450 MW combined load level, which represents the peak demand for the example day analyzed. Up to 500 MW PV penetration level was analyzed for the defined POI and the operational conventional generators were re-dispatch for each case to ensure the combination generator output power with the least cost is selected.

Contrary to conventional assumptions, increasing PV penetration does not only lead to increase in bus voltage. This capability for increasing solar PV capacity to lead to both increase and decrease in bus voltages was demonstrated in this study. Variations in bus voltage in some cases are due to substantial changes in power flow, hence significant changes in the voltage drop across the transmission lines. Utilities are typically regulated to maintain their bus voltages within certain limits, and this study assumes a violation when any of the bus voltages exceeds 1.1 or below 0.9 pu. Due to multiple factors including substantial circuit violations, networks solutions for PV capacity beyond certain values do not converge and such cases are only evaluated based on available solutions. The maximum and minimum bus voltages for the network varies based on the PV POI as illustrated in Figure 13. Hence, up to 320 MW PV capacity can be connected to any of the transmission circuit buses without any voltage violation.

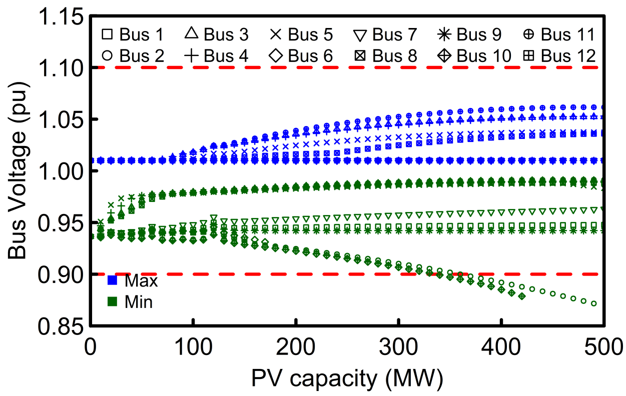

Figure 13. The maximum and minimum bus voltage variation for increasing PV capacity over multiple points of interconnection (POI). A PV capacity is undesirable if it leads to bus voltage variation above 1.1 or below 0.9 pu.

The maximum and minimum bus voltage in a transmission network is significantly influenced by the scheduled voltages of the connected generator units. Hence, a measure of the maximum and minimum bus voltages alone may not be able to capture the impact of increasing solar PV penetration. In addition to the maximum and minimum bus voltage limits, utilities are typically required to maintain bus voltage variation within certain values. This maximum voltage deviation can also be an indicator of the expected voltage variations due to the PV intermittency. For this study, a PV capacity that leads to bus voltage deviation that exceeds 0.08 pu is undesirable. The maximum voltage deviation varies based on PV capacity and POI as illustrated in Figure 14. Based on this analysis, up to 140 MW PV may be connected to any of the circuit buses with bus voltage deviations exceeding 0.08 pu.

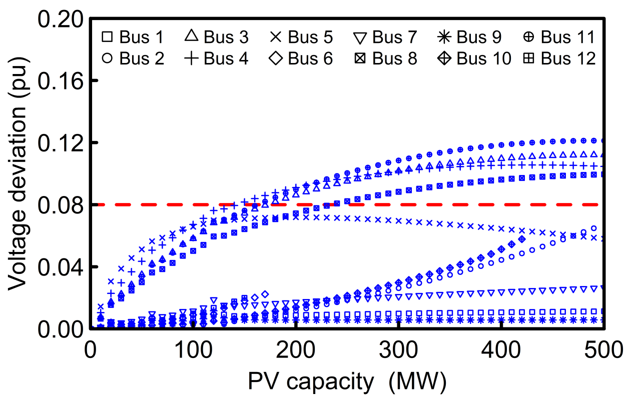

Figure 14. Maximum bus voltage deviation for defined PV capacity. A violation is recorded if the maximum voltage deviation exceeds 0.08 pu. The maximum voltage deviation is also an indicator of the expected voltage variation due PV intermittency.

Transmission line power flow are typically limited to restrict the temperature attained by energized conductors and the resulting sag and loss of tensile strength. This study focuses on the maximum PV penetration the network can sustain at steady state of a substantial period of time. Hence, the percentage loading for on all the transmission lines were evaluated for defined solar PV capacity. A thermal violation is recorded when the maximum transmission line loading exceeds 100% of its rated capacity. For the example network considered, buses 10, 11 and 12 are the least desirable for PV connection without overloading any of the transmission lines (Figure 15). Based on this analysis, up to 110 MW PV may be connected to any of the buses without any thermal violation.

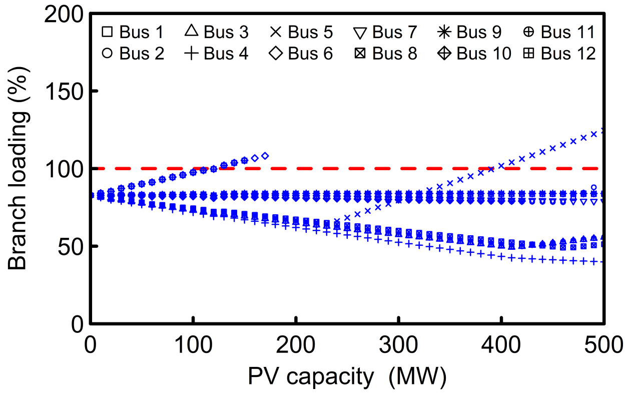

Figure 15. Maximum transmission line loading. Depending on the POI, PV integration may lead to substantial reduction in transmission line loading.

For this example study, a PV capacity is acceptable if all the bus voltages are within 0.9–1.1 pu, voltage differences with and without PV do not exceed 0.08 pu for any bus, and the thermal loading for any of the transmission lines is below 100%. Study is primarily focused on PV penetrations without significant changes to existing infrastructure, therefore, supplementary devices such as voltage regulators, capacitor banks, and other complementary tools were not considered. This study demonstrates that the maximum PV capacity without any network violation depends on the PV POI (Figure 16). Based on the maximum PV capacity for the analyzed cases without voltage or thermal violations, the preferred PV POI for the analyzed network are buses 1, 7 and 9.

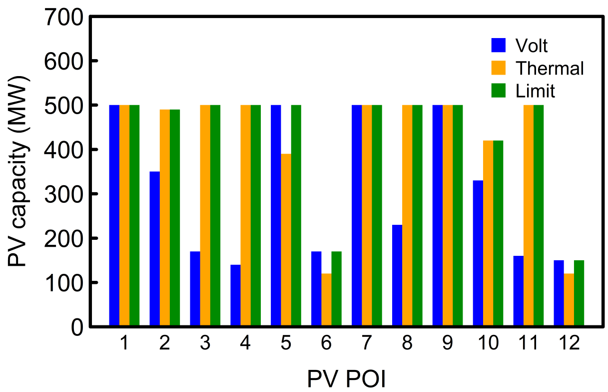

Figure 16. Maximum PV hosting capacity with respect to the circuit solution limit, voltage violation and thermal limits at peak load level.

7. Conclusions

This paper proposes an analytical framework, which includes a minute-to-minute economic dispatch model and a transmission network analyzing module for the evaluation of large solar PV impacts on both the generation and transmission systems. This framework can be employed for multiple applications including studies for estimating the maximum solar PV capacity a service area can support, the generation violations due to solar PV penetrations, the preferred location to connect solar PV plants, and the power system violations on the transmission network due to solar PV penetration. Furthermore, the proposed framework may be adopted for other intermittent sources such as wind power plants, and evaluate their effect on both the generation and transmission network system.

The detailed technical benefits for the proposed framework were demonstrated through the evaluation of the impact of increasing solar PV penetration on both the generation and transmission network for a modified IEEE 12 bus system with four conventional generators. Contrary to conventional approaches based on hourly dispatch models, the proposed technique employs a detailed minute-to-minute economic dispatch model to capture the impact of increasing PV penetration and identify periods of generation imbalance suitable for regulatory practices. Additionally, the framework was used to estimate the maximum PV hosting capacity for the transmission network with regards to the bus voltage and transmission line violations.

Based on the results for the example transmission circuit and generators responses for the day evaluated, the maximum capacity of the solar PV plant a service area can sustain without needing significant upgrades to the existing infrastructure depends on, the available unit specifications, the PV point of interconnections, and the voltage and thermal limits of the transmission network buses and lines, respectively. The results from the example 2248 MW system evaluated indicate that the system can sustain up to 400 MW, 17.8% of capacity, PV penetration without substantial generation violation and up to 120 MW PV plant can be connected to any of the buses in the transmission network without any voltage or thermal violation at peak load. The hosting capacity of the transmission network considering solar PV plants at multiple POI and the integration of battery energy storage systems to improve the acceptable PV capacity on the circuit are subjects of ongoing studies.

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 25

Responding Witness: David S. Sinclair

Q-25. Refer to the Supplemental Sinclair Testimony, page 11, lines 16–22.

a. Explain whether it is a common practice for LG&E to ignore significant uncertainties within its planning practices, including EV and customer load requirements.

b. If so, please provide all examples of LG&E ignoring significant uncertainties.

c. If not, explain and provide examples of how uncertainty is dealt with in other planning areas, such as distribution system planning.

A-25.

a. The Companies are proposing to update their avoided capacity and energy costs biennially. Because future laws or regulations will almost certainly be promulgated with more than a two-year notice, uncertainty regarding such laws and regulations should be ignored in this filing to ensure customers today do not pay inflated avoided costs. Thus, this uncertainty is being ignored as a matter of prudence. If new environmental laws or regulations are promulgated, the full cost of compliance will be reflected in the Companies' avoided capacity and energy costs in a future biennial filing.

The Companies' 2021 BP EV forecast is included in response to Question No. 21a. EV growth is not a significant uncertainty in this context. Electricity consumption per EV is only approximately 3 MWh per year, and EVs are assumed to charge overnight when solar generation is not available and such that there is limited impact on the Companies' need for capacity. The most significant load uncertainty pertains to the gain or loss of a large customer (e.g., a customer with a load greater than a 100 MW). However, because the Companies are closely involved when a large customer locates in the service territory and the process from concept to on-line date typically takes more than two years, any load impacts from the gain of a large customer will be fully reflected in a future biennial filing.

b. The Companies do not ignore significant uncertainties unless it is prudent to do so. For example, in the Companies' 2016 ECR filing (Case No. 2016-00026), significant uncertainty existed regarding the Clean Power Plan ("CPP") and Effluent Limit Guidelines ("ELG"), but compliance with these regulations was not expected to be required until 2022 at the earliest. Therefore, to avoid speculation regarding CPP and ELG compliance costs, the projects were evaluated based only on costs incurred and benefits produced through 2021. In doing so, the Companies demonstrated the projects were prudent even if the units stopped operating after 2021.

c. Uncertainty regarding future environmental laws and regulations has always been a consideration in the Companies' planning processes. In the analysis of responses to the Companies' 2019 Renewable RFP, the Companies demonstrated that the Rhudes Creek PPA was favorable in scenarios with a CO_2 price but given the uncertainty regarding future CO_2 legislation, the analysis focused almost entirely on scenarios with no CO_2 price. In the 2020 ECR filing, given the uncertainty regarding future environmental regulations, the Companies determined the year through which the units would have to operate to justify the ELG investment. In addition, the Companies evaluated the recommended ELG compliance plan in the context of a range of potential CO_2 regulations. The analysis showed that the recommended plan complied with current CO_2 regulations and would comply with CO_2 regulations like the CPP. In addition, the analysis showed that if coal units were replaced with renewables and peaking capacity as an alternative to ELG compliance based on concerns regarding future more stringent CO_2 regulations, and then no such regulations were passed, the downside risk associated with that decision would quickly far outweigh the downside risk associated with the ELG compliance decision.

   Distribution Planning has greater flexibility to deal with uncertainties than does Generation and Transmission Planning. Where uncertainties exist associated with capacity-based investments, the Companies closely monitor commercial, industrial, and residential developments to determine whether to accelerate or defer related projects. Lead times for materials procurement and project completion is typically much shorter and can be quickly delayed or suspended where projected loads (growth) are not being realized. Also, most distribution materials needed for capacity-based investments involve high-turnover items which can be reassigned to other projects if acquired before a project is deferred or suspended. Finally, where higher levels of risk exist, the Companies establish contracts with customers to reassign a portion or all risk to the cost causer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 26

Responding Witness: David S. Sinclair

Q-26. Refer to the Supplemental Sinclair Testimony, page 12, lines 1–2. Explain whether the contrary could also be true. In other words, explain whether LG&E's NMS II customers would be underpaid for capacity if stringent federal regulations were passed on carbon or that encourage clean energy procurement.

A-26. No. NMS-2 rates will be updated in each base rate case so any changes in avoided energy and capacity costs, whether due to future CO_2 laws/regulations or other factors, will be considered at that time. Also, the nature of future CO_2 laws/regulations are not known so it is unknowable how, or if, energy pushed on to the grid by NMS-2 customers would impact the Companies' future compliance obligations and costs.

What is known is that the *most* compensation NMS-2 customers should receive for energy delivered to the grid is the price of an equivalent product, e.g., 20-year level pricing for a utility-scale solar PPA, adjusted for avoided transmission and distribution capacity costs and line losses, if any. As the Companies have noted, their recent solar PPA has a 20-year level price of $0.02782/kWh with liquidated damages if the facility fails to meet guaranteed availability, and the Companies will receive all renewable energy certificates ("RECs") from the facility's production. This is an appropriate comparison because whatever the costs of "stringent federal regulations … on carbon or that encourage clean energy procurement" might be, they will be equally well avoided by utility-scale solar (or other renewable resources) as by net-metering-scale generators. There is nothing unique or special about rooftop solar in this regard: a kWh of energy delivered to the Companies' grid by a rooftop solar facility is *identical* with regard to its impact on carbon emissions or "clean energy procurement" as is a kWh delivered to the Companies' grid by a utility-scale solar facility (after adjusting for line loss differences, if any).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 27

Responding Witness: David S. Sinclair

Q-27. Refer to the Supplemental Sinclair Testimony, page 12, footnote 9.

a. Provide the intermittent renewable generation penetration levels considered in the report and compare those to LG&E.

b. Based on the results of the analysis provided, provide an opinion as to how similarly positioned California and LG&E are with respect to intermittent renewable generation penetrations.

c. Explain whether it is LG&E's position that California utilities and Kentucky utilities have similar clean energy policies and goals. If so, please provide support for that position.

A-27. The reference to the NRRI report was included simply to acknowledge that, while the Companies are aware that the industry is transitioning from reliability metrics like reserve margin, the Companies are currently comfortable computing capacity need as a function of reserve margin because the penetration of renewables in Kentucky is far less than in California. See Mr. Sinclair's Supplemental Direct Testimony at page 12, lines 21-23.

a. In 2020, solar and wind accounted for approximately 23% of total energy in California and less than 1% in Kentucky.

b. The penetration of renewables in Kentucky is currently far less than in California.

c. The Companies have no view on the "energy policies and goals" of California utilities or other Kentucky utilities. However, it is likely that the utilities in each state are responsive to the laws and regulations of the states in which they operate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 28

Responding Witness: David S. Sinclair

Q-28. Refer to the Supplemental Sinclair Testimony, page 16, lines 11–16, which states that customers have the option of choosing to execute a 20-year PPA or a 2-year PPA. For those that choose a 2-year PPA, at the end of the 2-year PPA period, explain whether a customer can then choose to enter into a 20-year PPA.

A-28. Yes, at the end of the 2-year PPA period a customer may then choose to enter into a 20-year PPA.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 29

Responding Witness: David S. Sinclair

Q-29. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-1, Avoided Energy Cost. Also refer to LG&E's Response to the Attorney General and KIUC's First Request for Information, Item 172, Attachment 2. Provide updated support for the revised avoided energy cost in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-29. See attachments being provided in Excel format. Attachment 1 provides updated support for the input assumptions used to calculate avoided energy cost in Excel format and demonstrates the calculation of hourly avoided energy cost for the marginal 1 MW. Because the calculation of hourly avoided energy costs through 2045 for renewable profiles greater than 1 MW is very data-intensive, the calculations were performed with SAS software using the same input assumptions and calculations shown in Attachment 1. Attachments 2, 3, 4, and 5 provide the results of this process for each proposed renewable resource type including the following details on an hourly basis for hours in which renewable generation is forecasted:

- the renewable generation profile,
- the specific generating units avoidable for each MW of renewable generation, up to 80 MW,
- the decremental operating level of the avoidable generating units for each MW of renewable generation, and
- the avoidable energy cost for each MW of renewable generation.

The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Attachments 1-5 are entirely Confidential and are being provided separately under seal in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 30

Responding Witness: David S. Sinclair

Q-30. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-2, Avoided Capacity Cost. Provide support for the avoided capacity cost amounts in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-30. See attachments being provided in Excel format. The first Excel workbook was used in the preparation of Supplemental Exhibits DSS-1 and DSS-2. The second Excel workbook provides a more straightforward calculation of the requested information.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 31

Responding Witness: David S. Sinclair

Q-31. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-2, page 3.

a. Explain how various contracting terms can impact PPA prices and provide examples.

b. Provide examples of all other utilities that LG&E is aware of that use the method to compute avoided capacity costs that the Companies have called "Current Market Price" (PPA price minus avoided energy cost).

c. Provide citations, including page references, to all studies, papers, or other literature that LG&E is aware of that describe or promote the method to compute avoided capacity costs that the Companies have called "Current Market Price" (PPA price minus avoided energy cost).

d. Describe and provide all research or outreach that LG&E has conducted to determine that customers are willing to pay more than avoided energy cost because they see some additional value from the PPA.

e. Describe and provide all research or outreach that LG&E has conducted to determine that customers perceive any relationship between solar PPA prices and avoided energy cost.

f. Describe the process LG&E used when they "sought a third-party source for renewable PPAs." List all third-party sources that the Companies encountered in this search, in addition to the LevelTen Energy PPA Price Index.

A-31.

a. The Companies' 2019 request for proposals for renewable energy resulted in proposals ranging between 10 and 200 MW in size and between 10 and 30 year terms. The attached chart shows the range of prices for the proposed wind and solar projects and demonstrates that 20 years was the proposed term for solar projects with the lowest prices as well as the greatest number of responses. The ibV-Rhudes Creek solar project with a 20-year PPA term had the lowest price of all the proposed projects. Certain information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

b. The Companies have not performed this research. The Current Market Price method is intended to be an intuitively straight-forward method. Whatever ability solar or wind resources have to avoid capacity and energy costs is available to customers through the cost of the resource. The Current Market Price method provides a means of allocating the resource cost to energy and capacity components. Furthermore, whereas the Companies would typically evaluate resources via a competitive process, the Companies have a legal obligation to purchase the output from a QF. By comparing avoided capacity cost estimates based on the Current Market Price and Levelized Cost of a CT methods, the Companies' methodology tries to mimic an outcome from a competitive process for QFs. For example, the Companies had to demonstrate to the PSC that the Rhudes Creek PPA is prudent for customers. There is no such "after execution" review for a QF because of the Companies' legal obligation to purchase.

c. See the response to part b.

d. Currently, the Companies have two business solar customers (Green Tariff Option #2), approximately 1,000 customers that purchase renewable energy certificates via Green Tariff Option #1, and approximately 3,000 customers that participate in the Solar Share Program. In addition, many large commercial and industrial customers have corporate sustainability goals that outline the additional value they see from renewable resources. In early 2020, the Companies entered into Renewable Power Agreements ("RPAs") under Green Tariff Option #3 with Dow and Toyota. The Companies are currently working with other large customers who have expressed interest in Green Tariff Option #3.

e. The best information that the Companies have regarding customers' perspective on the relationship between solar PPA prices and avoided energy costs is from discussions with existing (Dow and Toyota) and potential Green Tariff Option #3 customers. Based on these discussions, it is very clear that their interest in having the Companies' procure solar energy on their behalf is linked to the potential savings they might achieve.

f. The Companies used Google to search for solar PPA price indexes. LevelTen's quarterly price indexes were the primary results, and they were repeatedly cited by other apparently credible sources.[9] In addition, the recent

[9] *See, e.g.*, PV Magazine, "Solar PPA prices in the US rise for the second consecutive quarter — after 18 months of decline," Oct. 16, 2020, *available at* https://pv-magazine-usa.com/2020/10/16/after-18-months-of-decline-solar-ppa-prices-rise-for-the-second-consecutive-quarter/; Utility Dive, LevelTen: "Renewable

LevelTen indexes are consistent with the Companies' own recent experience with requests for proposals for renewable energy and capacity, as well as the PPA prices of Big Rivers Electric Corporation's recently approved solar PPAs, making the Companies comfortable that LevelTen is a credible source. Moreover, LevelTen describes its PPA marketplace as, "The world's largest two-sided marketplace for renewable energy power purchase agreements,"[10] and describes itself overall as "Powering the Renewable Energy Economy: Renewable transaction infrastructure to accelerate the clean energy transition,"[11] which does not indicate that LevelTen is in the business of underselling the promise of renewable energy.

In addition, LevelTen describes its chief executive officer as having "co-founded OneEnergy Renewables, a leading national developer of utility-scale solar projects," as well as having "led the Bonneville Environmental Foundation's nationwide investment in clean power projects, developing more than 160 solar projects in 16 states and establishing the highly acclaimed Solar 4R Schools program."[12] Also, LevelTen recently announced a new partnership with Sustainability Roundtable, Inc. to "help medium-sized businesses set and meet more ambitious and credible renewable energy goals through aggregated procurements of new, utility-scale renewable energy."[13] Again, this indicates LevelTen is in the business of encouraging renewable development, not undercutting it.

Although LevelTen appears to be a respected and credible solar PPA price index, the Companies are open to considering other credible sources of PPA pricing data.

PPA prices maintain upward trend as permitting, interconnection bottlenecks delay new projects," Apr. 21, 2021, *available at* https://www.utilitydive.com/news/levelten-renewable-ppa-prices-maintain-upward-trend-as-permitting-interco/598686/; Environment + Energy Leader, "New Report Shows Power Purchase Agreement Prices Rising Across North America," Oct. 21, 2020, *available at* https://www.environmentalleader.com/2020/10/new-report-shows-power-purchase-agreement-prices-rising-across-north-america/; Solar Builder, "Six takeaways from LevelTen's Q2 2020 North American PPA Price Index," July 29, 2020, *available at* https://solarbuildermag.com/news/six-takeways-from-leveltens-q2-2020-north-american-ppa-price-index/.

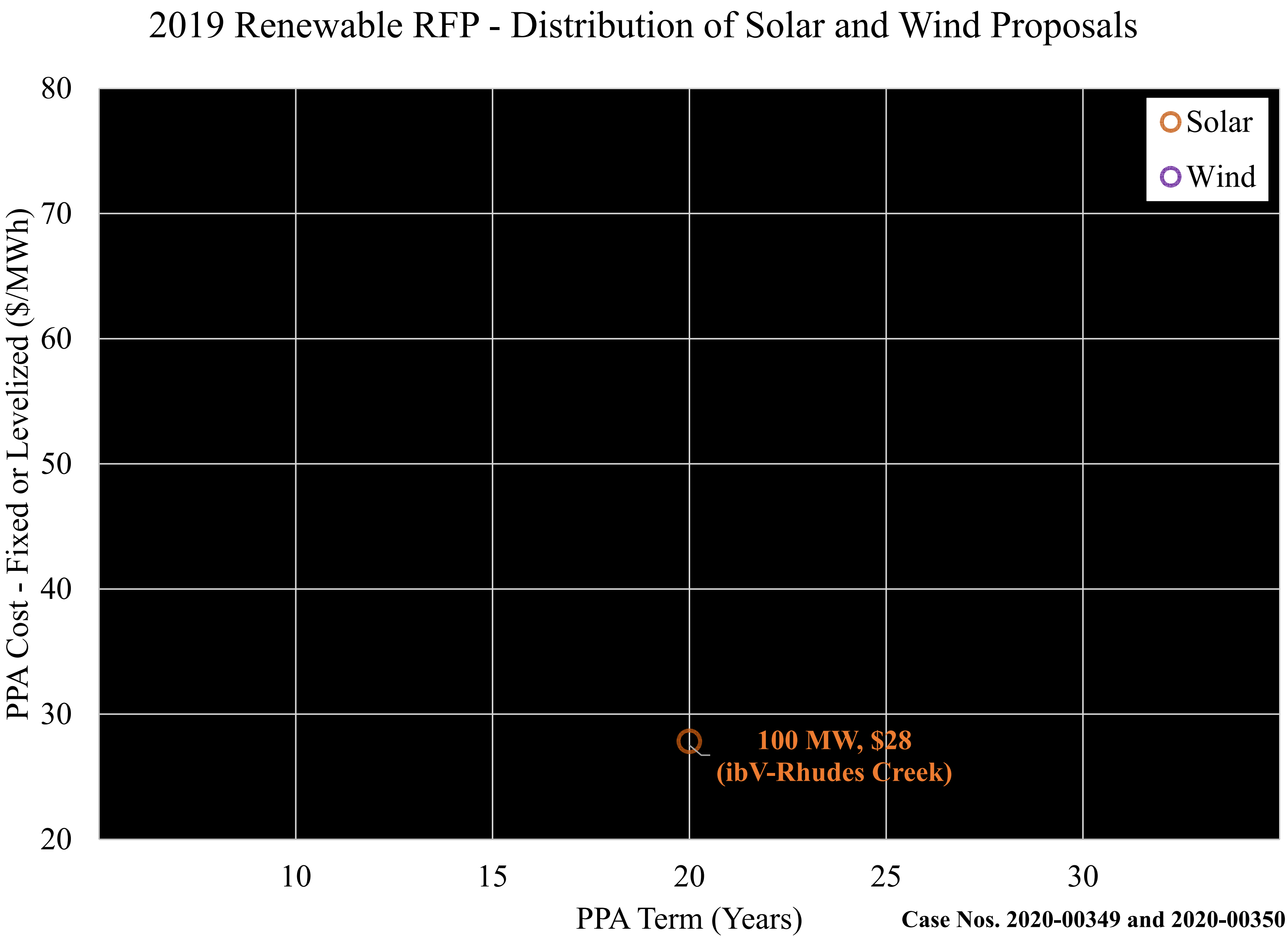
[10] https://www.leveltenenergy.com/platform/energy-marketplace (accessed July 26, 2021).

[11] https://www.leveltenenergy.com/ (accessed July 26, 2021).

[12] https://www.leveltenenergy.com/team/bryce-smith.

[13] https://www.leveltenenergy.com/post/sustainability-roundtable-strikes-partnership-with-levelten-energy

The Attachment is Confidential and provided separately under seal.



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Attachment to Response to PSC-7 Question No. 31(a)
Page 1 of 1
Sinclair

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 32

Responding Witness: David S. Sinclair

Q-32. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-2, page 7.

a. Provide the specific spreadsheet that LG&E used from National Renewable Energy Laboratory's 2020 Annual Technology Baseline to estimate overnight capital and fixed O&M costs, and identify the tab and cell numbers containing the values that the Companies used.

b. Provide the dataset that substantiates the LG&E's cost of firm gas transportation for the Trimble County CTs.

A-32.

a. See attachment being provided in Excel format. See Tab "Natural Gas," cells V236 and V256.

b. See attachment being provided in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 33

Responding Witness: David S. Sinclair

Q-33. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-2, page 8. Provide the dataset that indicates the hour in which LG&E's monthly peak most commonly occurred over the past 20 years.

A-33. See attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 34

Responding Witness: David S. Sinclair

Q-34 Refer to the Supplemental Sinclair Testimony, Exhibit DSS-2, page 9. Describe how LG&E calculated average annual availability factors in Table 8. Provide all workpapers behind those factors, all citations for any assumptions, and all raw datasets that informed the factors and the workpapers in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-34. See attachment being provided in Excel format. For each technology, the monthly availability factor is the technology's average capacity factor in the mode peak hour (i.e., the hour in which the peak most commonly occurred over the past 20 years), and the annual availability factor is the average of the monthly availability factors.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 35

Responding Witness: David S. Sinclair

Q-35. Refer to the Supplemental Sinclair Testimony, Exhibit DSS-3, Recommended LQF and SQF Rates.

a. Provide the avoided capacity prices as per kW prices.

b. Explain why there is no longer a time-of-day option for the avoided energy costs.

A-35.

a. This conversion cannot be performed. As described in Supplemental Exhibit DSS-2, the avoided capacity prices for the LQF and SQF riders for both solar types and wind were based on the Current Market Price method which starts with a PPA price that is in $/MWh and subtracts the Avoided Energy Price for that particular technology. A $/kW capacity price concept is not applicable to these technologies due to their intermittency and lack of dispatchability. This is why all of the solar and wind responses to the Companies' 2019 renewable RFP were quoted in $/MWh as were the LevelTen Energy PPA price indices described in Supplemental Exhibit DSS-2.
b. Avoided energy cost for each QF technology was computed based on each technology's generation profile and reflects the hours in which each technology is available.

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Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 36

Responding Witness: John K. Wolfe

Q-36. Refer to the Supplemental Testimony of John K. Wolfe (Supplemental Wolfe Testimony), page 2, lines 10-16.

a. Explain whether distributed generation customers are required to have smart inverters.

b. Explain the reliability implications of distributed generation having smart inverter versus traditional inverters.

A-36.

a. Although not called out specifically as "smart inverters", the Companies do require that all inverter-based generation comply with all applicable standards and are certified to comply with UL 1741/UL 1741 SA. Per the Companies' Interconnection Requirements for Customer-Sited Distributed Generation, which is a publicly available document posted on the Companies' website, "*any line commutated inverter that is electrically paralleled with the LG&E and KU system shall be tested and certified to UL 1741/UL 1741 SA by a NRTL certified by OSHA*". This certification verifies that each inverter is capable of "smart" functions such as real or reactive power response to voltage, and ride-through capabilities for grid disturbances in voltage or frequency.

b. Smart inverters can provide the capability to support the electric grid during grid disturbances and during normal operation, whereas traditional inverter-based resources typically shut off or disconnect from the grid during those disturbances, therefore resulting in negative reliability impacts to the grid where higher DG penetrations exist. Many smart inverter functions were developed in response to widespread grid disturbances where inverter capacity was lost. But none of these capabilities are available to the Companies without a Distributed Energy Resources Management System ("DERMS") and legal authority to control customers' smart inverters; simply having DERMS without having the right to control customers' smart inverters would not provide the capability described above.

Although the Companies do require all inverter-based resources to comply with UL 1741 and UL 1741 SA, the Companies do not currently specify settings for each of these functionalities other than default. Moving forward, proper management, and verification of inverter settings is crucial to prevent negative impacts from distributed generation interconnected to the distribution system. Again, a method to monitor and manage setpoints on grid-connected inverters, potentially through DERMS functionality, will be required to enable the resources to be utilized for grid services, and the Companies would need legal authority to control customers' smart inverters.

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Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 37

Responding Witness: John K. Wolfe

Q-37. Refer to the Supplemental Wolfe Testimony, page 2, lines 4–9. Provide all costs that have been incurred by LG&E (i.e., not a theoretical utility), and the methods for estimating said costs, by distributed generation that are not collected from customers through the interconnection process.

A-37. See the Companies' Response to Joint Intervenors' Post-Hearing DR No. 2.

Costs incurred by the Companies to accommodate net metering distributed generation and not collected from customer generators during the interconnection process include but are not limited to:

- Labor costs for administrating customer interconnection applications,
- Labor costs associated with inspections of customer installations,
- Labor and material costs required for replacing an existing meter with a bi-directional meter,
- Labor and materials costs for service transformer upgrades where the existing infrastructure did not meet modern standards or requirements,
- Labor costs required for making changes to protective relay settings on the distribution system due to changes in power flows or available fault current, and,
- Labor costs for modeling the impacts of proposed interconnections on the distribution system.

The Companies have not tracked these costs separately or in unique accounts and thus cannot provide detail of costs incurred specifically for interconnected net metering customers. The Companies estimate average costs of $850-$1,000 have been experienced for most interconnections, with some more complex installations approaching $2,900 in costs.

See also PSC 6-22 for anticipated future system issues that will add costs with increased penetration of net metering generation facilities and storage interconnected to the LG&E and KU distribution grid.

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Response to Commission Staff's Seventh Request for Information
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Case No. 2020-00350

Question No. 38

Responding Witness: David S. Sinclair

Q-38. Refer to the Supplemental Testimony of Justin R. Barnes (Supplemental Barnes Testimony), page 8, lines 3–4, in which he states that LG&E's most recent IRP indicates that the next capacity resource would be a natural gas combined cycle station. Explain whether that statement is still accurate.

A-38. The statement is inaccurate because it mischaracterizes the nature of the analysis in the 2018 IRP. The 2018 IRP did not evaluate resource retirements sequentially so there is no "next capacity resource." The 2018 IRP evaluated two generating unit life scenarios, three load scenarios, three gas price scenarios, and two CO_2 price scenarios (36 total scenarios). Table 5-15 in Volume 1 of the 2018 IRP contains the least-cost resource plans for each scenario (see below), which include NGCC, solar, wind, and batteries. In the 65-year generating unit life scenario, the Low and Base load forecast cases did not require replacement generation during the study period.

Table 5-15 from 2018 IRP: Long-Term Resource Plans

Generating Unit Life	Load Scenario	Gas Price	Zero CO_2 Price	High CO_2 Price
55-Year	Base	Base	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 400 MW Solar
		High	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 500 MW Solar
		Low	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 300 MW Solar
	High	Base	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 100 MW Solar
		High	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 500 MW Solar
		Low	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 200 MW Solar
	Low	Base	4 1x1 NGCCs	4 1x1 NGCCs, 300 MW Solar
		High	4 1x1 NGCCs	4 1x1 NGCCs, 500 MW Solar
		Low	4 1x1 NGCCs	4 1x1 NGCCs
65-Year	Base	Base	No additional changes	No additional changes
		High	No additional changes	No additional changes
		Low	No additional changes	No additional changes
	High	Base	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
		High	1 1x1 NGCC, 100 MW Batteries	1 1x1 NGCC, 300 MW Solar, 300 MW Wind
		Low	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
	Low	Base	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		High	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		Low	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs

Note: "No additional changes" in the Base load, 65-Year Generation Unit Life cases means no additional changes to the generation portfolio beyond the assumed retirement of Zorn 1 in 2021, the planned retirements of Brown 1 and 2 in 2019, and the expiration of the Bluegrass Agreement in 2019.

Note that since the Companies published their 2018 IRP, the only resource the Companies have planned to add is the 100 MW solar power purchase agreement.

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Question No. 39

Responding Witness: Eileen L. Saunders

Q-39. Refer to the Supplemental Barnes Testimony, page 15, footnote 12, in which he states that he was aware of a situation where a home on which a net-metered solar facility was installed was disenrolled in net metering upon creation of a new electric account for a renter at the same address. Explain whether LG&E requires new residents of houses with net-metered solar facilities to fill out a new net metering application before providing net metering bill credits.

A-39. LG&E does not require a new resident of a home that has net metering to complete another net metering application to receive bill credits.

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Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 40

Responding Witness: David S. Sinclair

Q-40. Refer to Case No. 2020-00061,[15] Direct Testimony of Stuart A. Wilson, Exhibit SAW-1, page 15 of 41. Provide an updated version of Table 14 (Generation Resources Assumptions) for 2023 and 2024 In-Service dates.

A-40. The following table reflects NREL's 2020 ATB cost data for capital costs for both 2023 and 2024 in-service dates.

[15] Case No. 2020-00061, Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge (filed Mar. 31, 2020).

Generation Resources Assumptions (2023/2024 In-Service; 2018 Dollars)

	Peaking Capacity (SCCT)	**NGCC**	**Solar[16]**	**Wind[17]**
Overnight Capital Cost ($/kW)				
2023 In-Service	915	991	1,173	1,402
2024 In-Service	898	977	1,122	1,372
Fixed O&M ($/kW-yr)				
2023 In-Service	11.39	12.86	14.03	41.43
2024 In-Service			13.43	41.08
Firm Gas Cost ($/kW-yr)	21	18	N/A	N/A
Variable O&M ($/MWh)	4.50	2.16	N/A	N/A
Heat Rate (MMBtu/MWh)	9.5	6.4	N/A	N/A
Transmission Cost ($/MW-Yr)	N/A	N/A	N/A	46,540
Nominal O&M Cost Escalation	2%	2%	(3.3%)-1.0%[18]	1.2%
Seasonal Capacity Ratio	1.09	1.04	N/A	N/A
Capacity Factor				
2023 In-Service	5-90%	10-90%	28.1%	42.7%
2024 In-Service			28.3%	43.1%
Production Tax Credit ($/MWh, After 2022)	N/A	N/A	N/A	0
Investment Tax Credit				
2023 In-Service	N/A	N/A	22%	N/A
2024 In-Service			10%	

[16] NREL 2020 ATB, Solar – Utility PV, Kansas City Moderate
[17] NREL 2020 ATB, Land-Based Wind, Class 5 – Moderate (to reflect wind energy imported to Kentucky).
[18] NREL's 2020 ATB assumes escalation of -3.3 percent in 2025 through 2030 and +1.0 percent in 2030 through 2050.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 41

Responding Witness: David S. Sinclair

Q-41. Provide the contract term and PPA price of all the Companies' solar PPAs signed in the past five years.

A-41. The Rhudes Creek PPA is the only solar PPA signed in the past five years. The term is 20 years and the price is $27.82/MWh with no escalation. The Companies will receive all renewable energy certificates, which they currently plan to sell to offset some of the PPA cost.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 42

Responding Witness: David S. Sinclair

Q-42. Refer to Case No. 2018-00348.[19]

a. Provide LG&E's annual CO2 emissions (in tons) associated with all projected energy supply scenarios for each of the next 25 years.

b. Provide LG&E's anticipated net load (in MWh) for each of the next 25 years. Define net load as provided and include all calculations and data used to isolate net load.

A-42. As requested, this information is taken from the 2018 IRP and does not reflect the planning assumptions utilized in the 2021 BP, which is the basis for Mr. Sinclair's Supplemental Direct Testimony.

a. See attachment being provided in Excel format. As stated in Section 4.3 of the Long-Term Resource Analysis of the 2018 IRP, annual revenue requirements (along with other associated data, such as CO_2 emissions) were evaluated for each portfolio over the five-year period from 2029 to 2033. The Companies' 2018 IRP did not contemplate any new resources online prior to 2029, and the IRP timeline of 15 years ended in 2033. The Companies did not calculate CO_2 emissions outside of this five-year period as part of this analysis.

b. The table below contains forecasted energy requirements (i.e., net load) per the 2018 IRP. Energy requirements are the sum of electricity sales to customers, company uses, and transmission and distribution losses.

[19] Case No. 2018-00348, Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (Ky. PSC Oct. 2, 2020).

2018 IRP 25-Year Energy Requirements Forecast (GWh)

Year	KU	LG&E	Total System
2021	20,153	12,353	32,506
2022	20,116	12,357	32,472
2023	20,094	12,366	32,460
2024	20,143	12,392	32,535
2025	20,113	12,389	32,502
2026	20,107	12,400	32,507
2027	20,102	12,409	32,511
2028	20,120	12,430	32,550
2029	20,086	12,417	32,503
2030	20,066	12,411	32,477
2031	20,063	12,423	32,486
2032	20,078	12,443	32,521
2033	20,052	12,435	32,486
2034	20,048	12,440	32,488
2035	20,043	12,444	32,487
2036	20,058	12,460	32,518
2037	20,028	12,444	32,472
2038	20,015	12,437	32,453
2039	19,995	12,424	32,419
2040	19,999	12,425	32,423
2041	19,962	12,404	32,366
2042	19,944	12,395	32,339
2043	19,932	12,391	32,323
2044	19,952	12,411	32,363
2045	19,927	12,402	32,329
2046	19,933	12,420	32,353

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Seventh Request for Information
Dated July 22, 2021

Case No. 2020-00350

Question No. 43

Responding Witness: David S. Sinclair / William Steven Seelye

Q-43. Where applicable, provide all Supplemental Exhibits for all of LG&E's witnesses as well as all supporting workpapers for each exhibit in Excel spreadsheet format with all formulas, columns, and rows unprotected and fully accessible.

A-43. See responses to Questions Nos. 22, 30, 33, and 34.