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. 2020-00349**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METER INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

RESPONSE OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
COMMISSION STAFF'S POST-HEARING REQUEST FOR INFORMATION
DATED MAY 5, 2021

FILED: MAY 19, 2021

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer 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.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of May 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, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities 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.

Lonnie Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of May 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, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer 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.

Kent W Blake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of May 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, **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 13th day of May 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, **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 11th day of May 2021.

Judy Schooler

Notary Public

Notary Public ID No. **603967**

My Commission Expires:

July 11, 2022

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 17 day of May 2021.

______________________________(SEAL)
Notary Public

Notary Public ID No. 20191350 0120

My Commission Expires:
May 12 2024

SARAH D WELLS
NOTARY PUBLIC
MY COMMISSION EXPIRES MAY 12, 2024
HENDERSON COUNTY, NC

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
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of May 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, **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.

J. K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 11th day of May 2021.

Judy Schooler

Notary Public

Notary Public ID No. **603967**

My Commission Expires:

July 11, 2022

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 1

Responding Witness: Daniel K. Arbough

Q-1. Provide the account in which KU/LG&E included the test-year SEEM expenses.

A-1. The Companies included the test-year SEEM expenses in FERC account 556900. A total of $23,000 is budgeted in the test year between LG&E ($9,660) and KU ($13,340). This expense is intended to cover start up and administrative costs for the program.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 2

Responding Witness: Lonnie E. Bellar

Q-2. Of the $10.766 million increase in in-line inspection, provide a breakdown of inspections performed in the high consequence areas, the medium consequence areas, and any other area.

A-2. A list of transmission pipelines with in-line inspection related expenses in the base year or test year which make up the $10.766 million increase are shown in the table below. The vast majority of pipelines in which LG&E performs in-line inspections contain high consequence areas and are therefore subject to integrity assessments under §192.921. In addition, there are reasons, other than high consequence areas, that can trigger in-line inspection regulatory requirements under §192.710 and §192.624. The table indicates some of the specific regulatory mandates for which in-line inspection will be used to satisfy on portions of each pipeline.

The term medium consequence area is not used in 49 CFR Part 192, but moderate consequence area is used. The presence of a moderate consequence area in and of itself does not trigger action. However, the presence of a moderate consequence area combined with other factors are used to determine if a pipeline is subject to §192.710 and to §192.624.

The only transmission pipeline which LG&E in-line inspects which does not have a section subject to the in-line inspection regulatory requirements under §192.921, §192.710 or §192.624 is the Doe Valley 8-inch pipeline. This pipeline is in-line inspected due to the population density along it and the higher threats to pipeline integrity applicable to it. Pipeline safety regulations in 49 CFR Part 192 dictate the minimum standard for inspections. An operator must determine what they believe is appropriate to do beyond the minimum standard to ensure pipeline safety. LG&E has determined it is reasonable and appropriate to in-line inspect every pipeline which it in-line inspects. These inspections are the best, lowest reasonable cost means of promoting the overall safety and integrity of the gas transmission system.

Prior to PHMSA publishing the *Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments* also known as the Mega Rule Part 1 on October 1, 2019, in-line inspection was already considered an industry best practice for integrity assessments of high consequence areas. The Commission has agreed: "the Commission finds that use of ILI tools to conduct integrity reassessment is preferable to other accepted methods." (In the Matter of: *Application of Louisville Gas and Electric Company for Approval of State Waiver of the Reassessment Interval Required by 49 C.F.R. 192.939*, Case No. 2017-00482, Order of June 3, 2019, p. 14). With the Mega Rule Part 1 now published, the benefits of using in-line inspection are much greater. The in-line inspection data can be used to satisfy not only the integrity assessments of high consequence areas under §192.921, but also new regulatory requirements under §192.710, §192.624, and §192.607. Other assessment methods permitted under §192.921 do not provide the same benefit.

Pipeline	High Consequence Areas (§192.921)	Required Assessments Outside of High Consequence Areas (§192.710)	MAOP Reconfirmation (§192.624)	Base Year	Test Year	Change from Base Year
Validation Digs (across the various pipelines)				$0.266	$1.312	$1.046
Center 20" ILI	No	Yes	Yes	$0.095	-	$(0.095)
Blanton - Paddy's ILI	Yes	Yes	Yes	-	$3.559	$ 3.559
Magnolia 16" ILI	Yes	Yes	Yes	$0.429	-	$(0.429)
Magnolia 20" ILI	Yes	Yes	Yes	-	$1.736	$ 1.736
Muldraugh - Piccadilly ILI	Yes	Yes	Yes	$0.057	-	$(0.057)
Doe Valley 8" ILI	No	No	No	-	$1.660	$1.660
Penile - Paddy's ILI	Yes	Yes	Yes	$0.033	-	$(0.033)
Riverport 12" ILI	Yes	Yes	Yes	-	$1.005	$1.005
WK B ILI	Yes	Yes	Yes	$0.686	$3.134	$2.448
WK A ILI	Yes	Yes	Yes	$0.074	-	$(0.074)
Total				$1.640	$12.406	$10.766

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 3

Responding Witness: Lonnie E. Bellar

Q-3. Regarding the Joint Reliability Coordination Agreement, state whether this will need to be filed at FERC and whether KU/LG&E will be the filing party.

A-3. An executed Joint Reliability Coordination Agreement would need to be filed with FERC; however, the parties are still engaged in substantive negotiations, so the primary filing party has not been determined. In the event the Joint Reliability Coordination Agreement is executed, LG&E/KU would make a filing with FERC to incorporate the Joint Reliability Coordination Agreement into the LG&E/KU electronic tariff records. LG&E/KU will make an informational filing with the KPSC if the Joint Reliability Coordination Agreement is filed with FERC.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 4

Responding Witness: Lonnie E. Bellar

Q-4. Provide an analysis that shows the evaluation of all options considered by LG&E to comply with the Mega Rule, including in-line inspections.

A-4. See attached.

Inline Inspection Technology Expansion

On October 1, 2019, PHMSA published the Safety of Gas Transmission Pipelines: MAOP reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments also known as the Mega Rule Part 1. The original draft of the proposed rulemaking was issued March 22, 2016. The rulemaking is PHMSA's response to the causation issues associated with the 2010 incident in San Bruno, California. The rulemaking established a number of new sections of federal pipeline safety regulations, including the following.

- §192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines
- §192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines
- §192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines
- §192.710 Transmission lines: Assessments outside of high consequence areas.

In 2018, LG&E expanded the suite of inline inspection technologies deployed in response to the rulemaking which was in progress and to achieve a higher overall level of pipeline safety. The inline inspection technologies now being used include inertial, geometry, axial magnetic flux leakage, circumferential magnetic flux leakage, electromagnetic acoustic transducer, and pipe grade sensors. Historically, only inertial, geometry, and axial magnetic flux leakage technologies were used in LG&E's system.

The technologies deployed support compliance with the new PHMSA regulations in a number of ways. The technologies confirm pipe grade and seam type required under §192.607. They also identify anomalies to be evaluated in Engineer Critical Assessments under §192.632. The Engineer Critical Assessments are used to reconfirm maximum allowable operating pressures under §192.624.

Section 192.624(c) provides six methods for reconfirming the MAOP of pipelines.

1. Pressure Test – Estimates for pressure testing range from $538k to $2.2M per mile based on 200 operator pressure test data points (The Interstate Natural Gas Association of America (INGAA), Safety of Gas Transmission Pipeline Rule, Cost Analysis, A Review of the Natural Gas Notice of Proposed Rulemaking (NPRM) and Preliminary Regulatory Impact Analysis (PRIA), July 7, 2016). Segments could fail the test and then need to be replaced which would be an additional cost. Pressure tests also require taking the pipeline out of service, potential interruption of service to customers, can be destructive, and would not provide quantitative data on the condition of the pipeline nor verification of material properties.
2. Pressure Reduction – This method requires the operator to reduce the pipeline's pressure to the highest sustained operator pressure during the previous 5 years (prior to Oct 1, 2019) and dividing by a minimum of 1.25. The highest sustained pressure must be achieved at a minimum cumulative duration of 8-hours for a continuous 30-day period and must account for upstream and downstream pressure differences. This method will not be a feasible solution in most cases, as it would inhibit the Company's ability to meet system supply requirements and maintain system reliability. In addition, reducing pressure does not provide quantitative data on the

condition of the pipeline, does not provide verification of material properties, and does not constitute an integrity assessment. Furthermore, a pressure reduction can cause future inline inspections being conducted to satisfy integrity assessment requirements to be at an increased risk of being unsuccessful.

3. Engineer Critical Assessment – This method involves leveraging inline inspection (ILI) data and performing in ditch repairs and testing. LG&E plans to primarily use this approach to reconfirm MAOP and verify material properties of the gas transmission pipeline on the LG&E system.
4. Pipe Replacement – Replacement of all gas transmission pipeline in order to satisfy MAOP reconfirmation and ensure verification of material properties going forward is not feasible due to the cost and potential timeframes for permitting and acquiring easements. However, in certain cases, replacement of the pipeline will be the best choice due to other drivers including age and condition, class designation and criticality to reliable operation of the system. In some cases targeted replacement may be used to facilitate use of ILI tools.
5. Pressure Reduction for Pipeline Segment with Small Potential Impact Radius (<150-ft). This method has similar requirements as the Pressure Reduction method (reduction factor is 1.1 instead of 1.25) and requires increased leak survey frequency. This method has the same disadvantages as Method 2.
6. Alternate Technology - Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. The alternate technical evaluation process would likely leverage inline inspection data to establish what anomalies exist in the pipeline and then use an alternate analysis method than outlined in Method 3 Engineer Critical Assessment. There is not currently an alternate analysis method established which has been deemed acceptable by PHMSA, but the approach would likely still require inline inspections to be performed.

Inline inspections are an excellent way of thoroughly and timely assessing pipe in a non-destructive manner. They are the only method of thoroughly inspecting long stretches of pipelines with the ability to gather robust data about the pipeline for the entire length being inspected. And the Commission has agreed: “the Commission finds that use of ILI tools to conduct integrity reassessment is preferable to other accepted methods.” (In the Matter of: Application of Louisville Gas and Electric Company for Approval of State Waiver of the Reassessment Interval Required by 49 C.F.R. 192.939, Case No. 21700482, Order of June 3, 2019, p. 14). The benefit of efficiently gathering data along the length of the pipeline is more critical as a result of the creation of §192.710 which requires integrity assessments to be completed in additional locations along the pipeline. Leveraging ILI data is the industry best practice and the most cost effective approach to reconfirm MAOPs, assess the condition of pipelines for safety, determine what actions are needed, if any, on pipelines to ensure continued safe operation, and gather the data needed to ensure our records are complete.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 5

Responding Witness: Lonnie E. Bellar

Q-5. State whether LG&E performs in-line inspections on pipeline segments that do not contain a high consequence area.

A-5. Yes. See the response to Question No. 2.

In addition, LG&E performs in-line inspections on one high-pressure distribution pipeline (Ballardsville). This pipeline was previously a transmission pipeline which had high consequence areas thus the pipeline had previously been modified to allow in-line inspection. It is now a high pressure distribution pipeline. As such, it is not subject to the high consequence area designation under PHMSA regulations. LG&E has determined it is reasonable and appropriate to in-line inspect the Ballardsville pipeline after reviewing the population density along the pipeline and system characteristics. The inspection is the best, lowest reasonable cost means of promoting the overall safety and integrity of the pipeline.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 6

Responding Witness: Lonnie E. Bellar

Q-6. Provide the miles of pipeline inspected using in-line inspections that are high consequence areas and the total miles of pipeline inspected using in-line inspections of all areas of LG&E's gas system. Provide these amounts for the past five calendar years and the next three years' projections, if available.

A-6. LG&E in-line inspects 35 miles of high consequence area pipeline, in addition to 218 miles of pipeline outside of high consequence area in its gas rate base. All of this pipe has been or will be in-line inspected in the eight-year period covered by this question. Because pipelines are typically in-line inspected from one end to the other, in the process of inspecting the non-contiguous high consequence areas pipe outside of high consequence area is also inspected. In addition, there are reasons, other than high consequence areas, that can trigger in-line inspection regulatory requirements under §192.710 and §192.624. See the response to Question No. 2.

It would be more expensive to in-line inspect only high consequence areas of a pipeline than to in-line inspect a pipeline's entire length. This is due to high consequence areas being non-contiguous along pipelines, new high consequence areas occurring due to land use near pipelines, the need to install in-line inspection launchers and receivers at each end of a pipe section being in-line inspected, and minimum charges from in-line inspection vendors for each tool run.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 7

Responding Witness: Lonnie E. Bellar

Q-7. Provide a copy of all studies indicating that using in-line inspections in lieu of other assessment methods is cost-effective

A-7. See the response to Question No. 4.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 8

Responding Witness: Lonnie E. Bellar

Q-8. If LG&E intends to use in-line inspections as the default assessment method for high consequence areas, explain how doing so in all instances or by default is "the method . . . best suited to address the threats identified."[1]

A-8. LG&E does not intend to use in-line inspection as its "default" assessment method for high consequence areas; rather, it is the ***only*** assessment method permitted under §192.921 which provides quantitative data on the condition of the entire length of the pipe within the high consequence area without excavating the entire pipeline the full length of the high consequence area. Excavating the full length of the high consequence area would not be feasible or cost effective and would increase risks to pipeline safety. See the response to Question No. 2.

[1] 49 CFR Section 192.937(c)(" Assessment methods. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment.")

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 9

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-9. Explain whether the Commission should review the Certificate of Public Convenience and Necessity (CPCN) provided to LG&E in 2017 for the Bullitt County natural gas pipeline project given the material change in projected cost, including the expectation that LG&E's most recent cost estimates are outdated. Any explanation should include a conversation about the Commission's reasonable, least-cost alternative CPCN standard and how that standard is implicated given the material change in projected cost.

A-9. LG&E does not believe a further review of the CPCN provided to LG&E for the Bullitt County natural gas pipeline project is necessary. LG&E's most recent construction bids expired pursuant to their own term. LG&E will let the bids again when the construction date is more certain, but LG&E disagrees that its cost estimates are outdated. LG&E's budgeted amount for the project is detailed, well informed, and reflects LG&E's experience with this project, as well as the bids that have been submitted from the market. The difference between having open bids and a sound cost estimate is significant for purposes of responding to this request.

When LG&E obtained a CPCN in 2017, it explained that the pipeline was needed for reliability and to allow for further growth in the area due to capacity constraints. Since it was issued, the necessity for the CPCN has become even clearer, as drivers for increased demand in the area provided in 2017 have now occurred. As an example, LG&E's response to PSC 3-25(a) in Case No. 2016-00370 anticipated light industrial/warehouse buildings in the Cedar Grove, Hwy 480, Hwy 245 and Hwy 61 areas, which is occurring, and a new interstate exit, which is now in operation. As to reliability, 9,500 existing customers depend on service from a line in Mt. Washington, and an outage along the line could result in thousands of customers' natural gas service being interrupted. With regard to capacity, there is no longer any availability for new natural gas hookups in the area. At present, 450 homes and businesses have been denied requests for new or expanded natural gas service. These denials include residential developments, a parish, restaurants, hotels, and schools. The denials of service will continue until the pipeline is constructed. There is no credible suggestion that the additional capacity is not necessary to provide requests for new service or existing safe and reliable service.

LG&E has obtained approximately 90% of the right-of-way necessary to construct the pipeline. The small minority of outstanding rights-of-way are involved in condemnation actions. In those actions, LG&E is requesting an easement to construct the pipeline that will be installed below the surface. LG&E is not proposing to take any property in fee or alter the general use of the property, which is largely farming. The easement sought on property recently acquired by the Isaac W. Bernheim Foundation runs along an existing electric transmission line in an area that is not open to the public and far removed from Bernheim's recreational areas. The effects on the properties following construction are minimal. Further depictions can be found at https://lge-ku.com/bullitt-county-pipeline. On May 18, 2021, the Bullitt Circuit Court entered an order directing seven of the remaining property owners to make conveyance to LG&E the rights and easements sought by LG&E in the condemnation actions should no exceptions be taken to the judgement.

LG&E has updated the Commission in each rate case regarding the estimated cost to construct the pipeline. The $74 million current estimate has been influenced by several factors. First, the estimate includes a significant amount of contingency costs and accounts for the possibility of stand-by construction days due to reasons including, but not limited to weather and unforeseen delays in construction. Second, the Company expects bids were influenced by LG&E's inability to specify a start date for construction due in part to the outstanding rights-of-way.

LG&E has continuously assessed whether the pipeline is the least-cost reasonable alternative for the reliability and capacity concerns that have become pressing problems since the CPCN was issued. In addition to the studies LG&E presented to the Commission in the 2016 rate case in which the CPCN was issued, LG&E subsequently performed additional analyses that considered other alternatives, including looping, intermediate looping, and liquefied natural gas. As shown in response to Question No. 10, LG&E's most recent economic analysis continues to show the Commission's reasonable, least-cost alternative CPCN standard continues to be satisfied for this project given the other options for serving this rapidly expanding area of the Commonwealth. Once the outstanding rights-of-way are secured and a specific start date for construction can be established with more reasonable certainty, LG&E plans to rebid the construction costs for this project to obtain the lowest reasonable cost for the project. Although LG&E will need to rebid the construction contract, LG&E's current budget estimate is not out of date.

In each of these reviews, the pipeline for which the Commission issued a CPCN has remained the lowest cost option to address the reliability and capacity constraints in Bullitt County. Had any of these analyses resulted in a determination that the pipeline was no longer the lowest cost option, LG&E would have filed an application with the Commission seeking approval of the new project and notifying the Commission that it was allowing the CPCN for the pipeline to lapse.

A further review of the CPCN is particularly unnecessary because the issuance of a CPCN is not a finding that the utility can recover the construction costs in rates. It instead is a finding there is a need for such facilities and an absence of wasteful duplication, meaning a thorough review of all reasonable alternatives has been performed. The record regarding these points is undisputed; the pipeline is sorely needed and there is no lower cost reasonable alternative. The Commission will subsequently review the costs incurred to construct the pipeline to ensure they are reasonable for recovery in rates.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 10

Responding Witness: Lonnie E. Bellar

Q-10. Provide a copy of the most recent economic analysis of the Bullitt County natural gas pipeline project.

A-10. Results from the most recent analysis are shown in the table below. The pipeline estimate in this analysis and the current estimate are based on construction bids received from a second bid solicitation. The estimate for the pipeline option in the analysis below was lower than estimates for alternate routes reviewed.

Alternative	PVRR ($M Dollars)	Levelized RR/ccf[2] ($)	Levelized RR/ccf less Incremental Revenues[3] ($)
Pipeline	79.2	0.509	0.359
Looping	107.8	0.796	0.651
Intermediate Looping	43.0	2.315	1.753
LNG	320.3	1.921	1.770

[2] Levelized revenue requirements per incremental ccf of gas served.
[3] Incremental revenues are estimated based on current rates.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 11

Responding Witness: John K. Wolfe

Q-11. Provide all studies in KU/LG&E's possession or conducted by KU/LG&E involving the installation and use of Distributed Energy Resource Management System.

A-11. As indicated in the response to PSC 6-10, "LG&E and KU personnel have investigated and studied alternatives for managing DER on its distribution system through participation in industry committees, meeting with other utilities with higher DER penetration, evaluating associated regulation changes and outcomes in other states, and reading industry publications."

The Companies continue to monitor developments in DERMS technology through involvement in industry organizations and discussions with peer utilities. Additionally, trends in interconnection applications received will play a role in DERMS justification.

See attached documents.

ELECTRIC POWER RESEARCH INSTITUTE

UNDERSTANDING DERMS

June 2018

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DERMS Origins

With the rapid deployment of distributed energy resources (DER), there is a high level of interest in how these devices can be integrated with utility operations at all levels for management and monitoring purposes. This integration is challenging in that the number of devices is high and that ownership is often that of a customer or third party.

Industry stakeholders first began to address DER integration by identifying and standardizing the functions that individual DER can perform autonomously, in a distributed manner. Device-level functions like "voltage ride-through", "volt-var", "frequency-watt", and "dynamic reactive current" were designed and documented and are now supported by communication standards and grid codes worldwide, making grid-supportive capabilities mandatory for new interconnections.

This was a first step. A necessary step, but not sufficient to achieve end-to-end integration of DER with the grid. **A substantial gap was recognized between the granular controls of individual DER and the type of organized services needed for grid support, integration with distribution management systems (DMS) and grid operations.** In 2012, stakeholders began working to define a common set of grid-supportive services and means to integrate large quantities of DERs into utility systems in a way that is practical, sustainable and extensible. Because multiple parties could be involved; utilities, DMS providers, DER aggregators and facility/microgrid controller providers are working together.

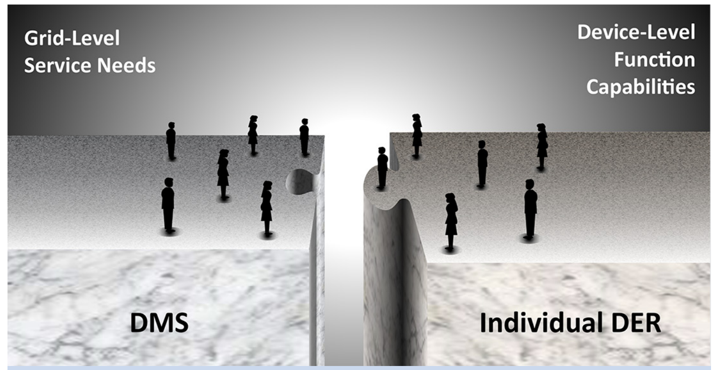
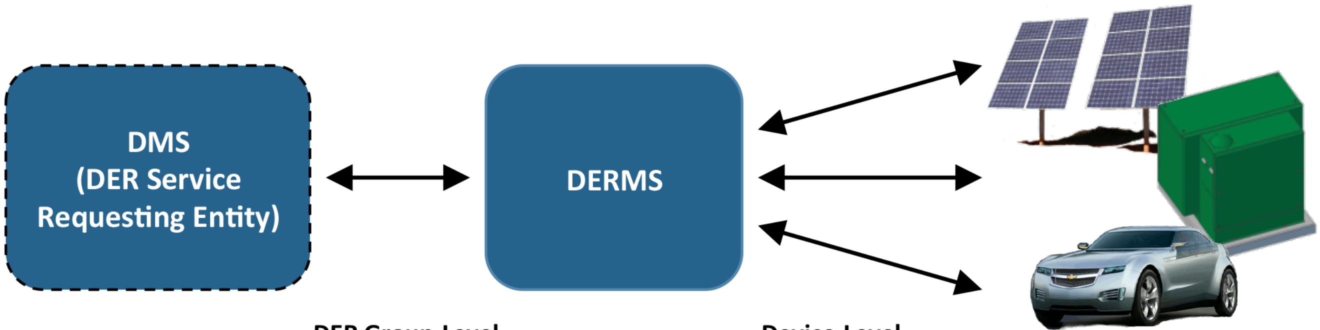


Figure 1 – The Gap Addressed by DERMS

Several needs have been targeted:

- ***Quantity:*** To be utilized effectively in a power system, DER will have to work in harmony with other control devices: load tap changers, capacitors, voltage regulators and switches. Their capabilities will have to be aligned with the power system: by feeder, phase, circuit segment, etc. This requires a flexible means to aggregate DER into groups by which they can be viewed and managed collectively.
- ***Complexity:*** The many complex functions of smart inverters coupled with their continuously-variable settings results in an infinite number of potential settings and multiple ways to achieve similar outcomes. DMS algorithms are concerned with the net effect of such settings on the grid, not the specific functions or settings used to achieve the effect.
- ***Sustained Nature of Service:*** Power system management systems need services provided in a stable, sustained fashion. Because many DER are variable (e.g., solar), achieving this involves intelligence, and potentially frequent adjustment of device settings to maintain targets set for DER groups.

A logical component that satisfies these needs is called a DER Management System, or DERMS. In short, a DERMS bridges the gap between DER group-managing entities, e.g., a DMS, and devices by taking the complex capabilities of many and presenting them as a simpler more manageable set of services.



DER Group-Level
- Fewer groups
- Less frequent interactions
- Device-type agnostic
- Simple settings
- Net result-based

Device-Level
- Many devices
- Frequent interactions
- Device-type specific
- Complex settings
- Explicit instructions

Figure 2 – DERMS Functionality

DERMS Core Capabilities

As described later, a DERMS can be integrated at a wide range of levels and can vary broadly in scale. Regardless of the placement or scale, a DERMS provides several key functions:

- *Aggregation*: DERMS take the services of multiple (potentially millions) individual DER and present them as a smaller, more manageable, number of aggregated virtual resources that are aligned with the grid configuration. How DER are organized into groups is in itself a research question and must be flexible.
- *Translation:* Individual DER may speak different languages, depending on their type and scale. DERMS handle these diverse languages, and present to the upstream calling entity (e.g., a DMS) in a cohesive way.
- *Simplification:* DERMS provide simplified aggregate services that are useful to distribution operations. The services are power-system centric rather than DER-type centric. Complex device-level settings, such as volt-var curve points and fast iterative settings updates are abstracted away as services are achieved and sustained. The simplified services provided by DERMS are standardized supporting the ability of multiple upstream calling entities.
- *Optimization*: A given service to be provided by a DER group may be achieved in many ways. Different smart inverter functions may be best at different locations or times. Different types of DER (e.g., storage, advanced loads, or solar) may make more sense in one circumstance than in another. DERMS provide requested grid services in the optimal way – saving cost, reducing wear, and optimizing asset value.

These functionalities are important to DER aggregators and downstream energy management system providers because these are intended to be products with intelligence, not as passive communication routers. Innovation is in these areas is beneficial to all stakeholders, improving efficiency and quality, rendering requested services from DER-groups in creative ways that optimize the service to the utility, the interests of the consumer and the lifetime economics of the DER resource.

Organizing DER into Groups

The effectiveness of the "aggregation" aspect of DERMS depends on how well groups of DER are organized. This is an ongoing area of research at EPRI - a new science in which best-practices will emerge over time. Industry stakeholders have identified many ways that one might choose to organize: by feeder, by segment, by phase, by DER type, etc. The standards that have been created (described later in this paper) make no limitation in this regard and allow that any list of DERs could be established as a group if desired.

Perhaps more interesting than "how" DER are organized is "who" organizes them. This question is often posed relative to a DMS and one or more DERMS. The technical answer is that the standard messages are structured so that either entity could create and declare the group to the other. And either could accept or reject this message. This symmetry was put in place because there were both DMS and DERMS providers participating in the standards process that wanted the ability to create groups. The more practical answer is probably that the DMS or upstream entity will create DER groups and declare them to the downstream DERMS. This is likely to create more use value of the group because the entity forming the group is the one that will be requesting its services.

The process of forming a DER group is straightforward, with standard messages that include a list of unique identifiers (mRIDs) for each member of the group and a unique group name. Other messages can query for existing groups, check group version/revisions, perform group maintenance, adding or deleting members from a group, or delete a group. In a simpler implementation, group definitions could be manually set and agreed-upon by DMS and DERMS.

Example DERMS Use Case

An example use case of DERMS is to utilize DER in the management of voltage and VARs on an electric distribution system. By aggregating the monitoring and controllability of many DER, DERMS provides additional control levers for the DMS. A DMS based voltage and VAR optimization algorithm could, for example, require control zones to be delineated by each voltage control device (load tap changer or voltage regulator) as shown in Figure 1. Here, four feeders are divided into six sections, which are further separated by phase to create 18 different control zones. The DER on this circuit could then be assigned to one of 18 groups, associated with these control zones.

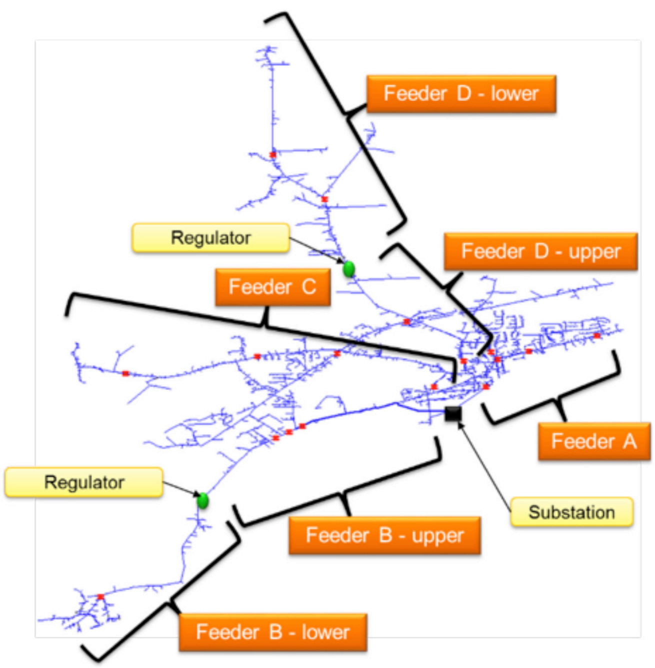


Figure 3 – Example of DER Groups Created for VVO

As system conditions or objective functions change over time, the DMS would analyze those changes and issue new instructions to the voltage and VAR controlling assets. In addition to settings or direct control of the traditional utility devices (load tap changers, line regulators, capacitors) the DMS would consider how the group-level services of the DER could be utilized and send commands to the DERMS accordingly. The DERMS would then translate these group-level commands into optimized settings changes (PF setpoints, volt-var curves, watt curtailment, etc.) or direct commands (load management, storage dispatch), to achieve the desired aggregate outcome. DERMS would then monitor and modify device settings for the duration of the service request in order to sustain it. Other DERMS use cases being actively researched by EPRI include Distribution Automation, Distribution State Estimation, and Forecasting.

Standards for DERMS Interfaces

Standardization at DERMS interfaces is necessary to support natural system expansion. Due to the large number of potential actors and interfaces in the DER integration space, custom/proprietary integration is not practical other than for simple one-off demo projects. Both at the device-level (DERMS-to-DER) and at the DER-group level (DMS-to-DERMS) there will likely be multiple systems and multiple companies involved. Even in the early stages of DER integration if there is a single DERMS and single brand of DER being managed, it is advised to use standards so that the system can be sustained and expanded going forward.

In this context, "standards" refers to two primary things:

- *Standard Function/Service Definitions:* Consistent behaviors to be implemented and provided by DERMS and device providers and to be expected, understood and utilized by DMS systems.
- *Standard Protocols and Information Models:* Consistent communication encodings that allow system components from multiple vendors to be integrated without requiring custom mapping software for each.

Standard Functional Capability at DERMS Interfaces

From the utility perspective, it is not practical to have each DER aggregator or device vendor independently define the grid-services or protocols that they can provide. There are potentially thousands of entities that may offer such services and it is not reasonable to expect distribution control strategies that deal uniquely with each type of offered service.

Likewise, from the vendor's perspective it is not practical to have each utility or DMS provider independently define the services or protocols that they can utilize. There are many utilities, and vendors need volume and consistency in the market in order to provide quality products at feasible costs.

Table 1 – Standards for Functionality at DERMS Interfaces

DER-Group Level (DMS-to-DERMS) Interface	Device Level (DERMS-to-DER) Interface
Standard Group-Level Function Definitions: IEC 61968-5 (Common Information Model for DER)	**Standard Device-Level Function Definitions:** IEC 61850-7-520 and information model in IEC 61850-7-420
Public EPRI report for reference: Common Functions for DER Group Management, Third Edition[1]	**Public EPRI report for reference:** Common Functions for Smart Inverters, Fourth Edition[2]
Defined DER Group-Level Grid Services: • DER Group Creation • DER Group Version and Member Query • DER Group Deletion • DER Group Maintenance (Adding, Updating, and Deleting Members) • DER Group Capability Discovery • DER Group Status Monitoring • DER Group Forecasting • DER Group Historical Aggregate Meter Data • DER Group Maximum Real Power Limiting • DER Group Ramp Rate Limit Control • DER Group Phase Balance Limiting • DER Group Real Power Dispatch • DER Group Reactive Power Dispatch • DER Group Voltage Regulation Function • Set DER Group Curve Functions • Provide Price to DER Group • Request Cost of Service from DER Group • Manage Power at a Point of Reference • Connect/Disconnect DER Group	**Defined DER Device-Level Functions:** • Connect/Disconnect Function • Limit DER Power Output Function • Energy Storage: Direct C/D Function • Energy Storage: Price-Based C/D Function • Energy Storage: Coordinated Charge/Discharge Management Function • Fixed Power Factor Function • Volt-Var Function • Watt-Var Function • Volt-Watt Function • Frequency-Watt Function • Watt-PowerFactor Function • Price or Temperature Driven Functions • Low/High Voltage Ride-Through Function • Low/High Frequency Ride-Through Function • Dynamic Reactive-Current Support Function • Dynamic Real-Power Support • Dynamic Volt-Watt Function • Peak Power Limiting Function • Load and Generation Following Function • Status Monitoring Points
DER Grid Codes with Functional Requirements: DER Grid Codes are not applicable at the group level	**DER Grid Codes with Functional Requirements (U.S. Examples):** • IEEE 1547-2018 (specific set of device-level functions required, three protocol options) • CA Rule 21
Functional Testing: Not yet available. See protocol testing in the next section.	**Functional Testing:** • IEEE 1547.1 – test specification for IEEE 1547, expected Q1 2019. • UL1741SA - Supports Rule 21, to be updated to support 1547.1

1 *Common Functions for DER Group Management, Third Edition.* EPRI, Palo Alto, CA: 2016. 3002008215.
2 *Common Functions for Smart Inverters: 4th Edition.* EPRI, Palo Alto, CA: 2016. 3002008217.

Standard service/function definitions and protocols for DERMS exist and are being actively improved and maintained. Utilities engaged in DERMS projects are encouraged to consider and build upon these standards, offering improvements and extensions as learnings occur. Table 1 provides a concise summary of standards and related documents that support DERMS interface functionalities.

Standard Protocol Capability at DERMS Interfaces

Communication protocol standards have been developed to support DERMS interfaces. The encodings continue to be improved and may or may not be supported in given products. For both scalability and sustainability, communication protocol standards should be required at DERMS interfaces. Table 2 provides a concise summary of standards and related documents that support DERMS interface protocols.

Table 2 – Standards for Communication Protocols at DERMS Interfaces

DER-Group Level (DMS-to-DERMS) Interfaces	Device Level (DERMS-to-DER) Interfaces
Standard information Model: IEC 61968-5 (Common Information Model for DER)	**Standard information Model:** IEC 61850-7-420
Protocol Encodings for DER Groups: • IEC 61968-100:2013 "Application Integration for 61968 Profiles" • MultiSpeak 5.0 • OpenFMB (alignment/mapping in process) • OpenADR 2.0 (mapping being considered)	**Defined DER Device-Level Functions:** • SunSpec Modbus • DNP3 AN2013-001, AN2018-001 • IEEE 2030.5 • IEC 61850-8-2
DER Grid Codes with Protocol Requirements: Not Applicable at the Group Level	**DER Grid Codes with Protocol Requirements:** • Multiple worldwide, unique by region • IEEE 1547-2018 (specific set of device-level functions required, three protocol options) • CA Rule 21
Protocol Testing: UCAI Users Group, CIM for DER compliance testing.	**Protocol Testing:** • IEEE 1547.1 – test specification for IEEE 1547, expected Q1 2019, mandates that DER support at least one of three standard protocols (DNP3, SunSpec Modbus, 2030.5) includes communication/interoperability test requirements. • UL1741SA - Supports Rule 21, to be updated to support 1547.1 • SunSpec Alliance – defines test requirements for the three 1547-specified protocols.
Protocol Certification/Listing: UCAI Users Group, CIM for DER certification and listing.	**Protocol Certification/Listing:** SunSpec Alliance provides certification listing for the three 1547-specified protocols.

DERMS is a Logical Entity

As utilities lay plans for DER integration, it is important to recognize DERMS as a logical entity, not necessarily a physical one. This means that DERMS may be a stand-alone software, or may be bundled with other functionality in combination software products.

This is normal. As an example, consider the logical definition of an Outage Management System (OMS). We know what it is, we can describe its individual purpose and capabilities, and yet vendors often bundle OMS capability with DMS, Work Management Systems, or other systems. The same is true of Geospatial Information Systems, Customer Information Systems, and others that are sometimes bundled.

"DERMS" is a function – a capability to perform a certain set of actions as will be discussed below. A given utility architecture may elect to have DERMS stand-alone or be integrated with DMS, or both. Over time the architecture is likely to evolve. In any case, the role and function of each should be defined and specified separately. If bundled products are used, it is critical that the DMS-to-DERMS interface be exposed and accessible so that other DERMS (other managed aggregations of DERs) can be integrated into the system. Without this the system is neither scalable nor sustainable.

Starting Simple: Manually-Operated DERMS

A DERMS does not have to be driven automatically by a DMS, it may be used standalone - driven manually by human operators. For many utilities the needs for adjusting DER settings are infrequent. DERMS may be used, for example, to make seasonal adjustments of power factor to optimize relative to winter and summer loads or to limit DER export power on a handful of peak days per year.

In these cases, the operator may be provided a user interface with the same basic set of DER group-level monitoring and management services as would be available to a DMS.

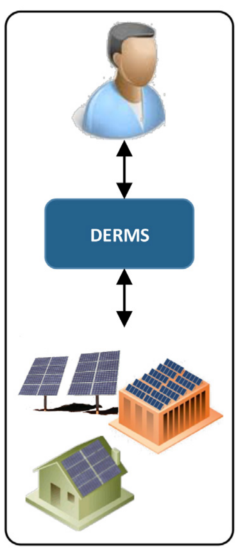


Figure 4 – Manually Operated DERMS

Evolving: DERMS Quantity, Placement and Scale

Utilities may first focus on a single centralized DERMS – a system that will reside in the operations center alongside DMS, Outage Management Systems (OMS) and other large-scale applications. While this may be a proper place to start, the architecture should consider that DER aggregation will eventually happen at multiple levels, and that multiple parties may be involved.

Figure 5 illustrates this principle through an example. In Stage 1, the utility employs a central DERMS which may work alongside or within their DMS. This DERMS connects to the DER that the utility initially intends to manage, making these devices an active part of the system operations. In Stage 2, the system is expanded with third party solar aggregators, storage fleet managers, or any other DER managing entity playing a role in the overall architecture.

In Stage 3, the system is further expanded with distributed DERMS, DER aggregation and management performed downstream, such as at the feeder, community, facility or home-level. Each of these points of distributed intelligence is a DERMS in its own right, providing the same basic logical functions as the central DERMS.

The work of standards groups regarding methods for DER group-level management has been influenced by prior work in the demand response area that enabled aggregation to occur at multiple levels. Accordingly, the standards that have emerged for DERMS apply equally to large-scale central DERMS, feeder-level controllers placed at substations, microgrid controllers, advanced energy communities, or facility/home energy management systems. The methods can be nested, and the services of multiple downstream DERMS (such as third-party aggregators) can be utilized directly or rolled-up into upstream DERMS (such as a central utility application).

A key principle here is that the interface between DERMS and DMS is of critical importance architecturally. While there is no issue with having a DERMS capability included within a DMS, it is not rational to view this as the only DER aggregating system that will be involved. To ensure system scalability and sustainability, the DERMS-to-DMS interface should be accessible.

Another key principle is that DER management can begin in a simple form, such as a single central software application as described in the previous section. Later, if desired, intelligence can be distributed and the overall DER management approach made a system-of-systems as shown in Figure 5.

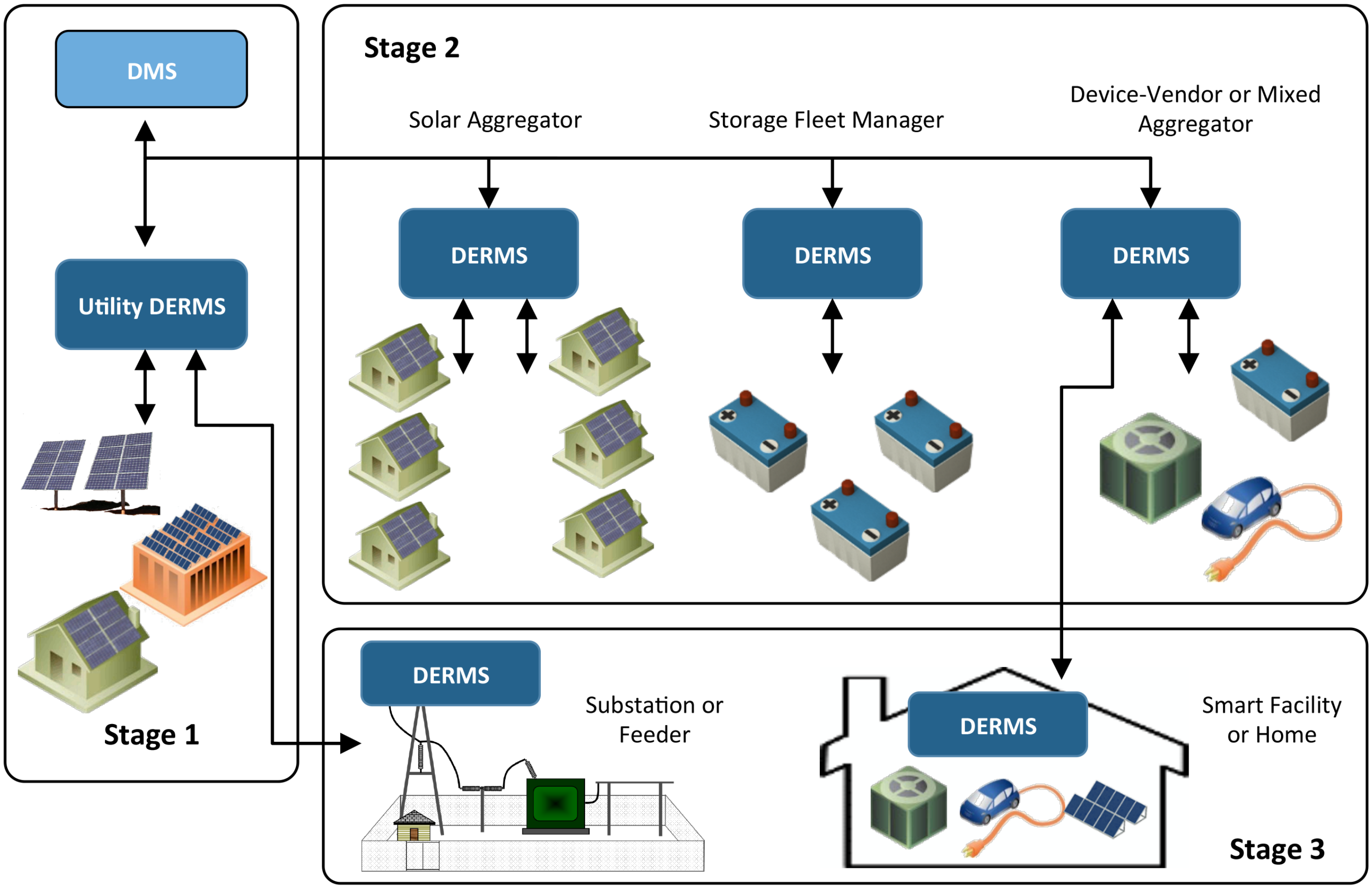


Figure 5 – Central, Distributed, and Hierarchical DERMS Functionality

DERMS vs. DER-Ready DMS

When the term "DERMS" found its way into utility dialogue, a wide range of existing products and systems were quickly advertised as being or including DERMS. Certain providers of DMS, distribution automation, vendor/customer headends, load management software, building automation and home energy management presented their products as DERMS, whether or not they provided the core capabilities or supported the standard service definitions that are necessary for cohesive integration of multiple DER.

A common point of confusion is that of "DERMS" versus a "DMS that is DERMS-ready". Conventional DMS control voltage regulators, capacitor banks, and circuit configuration via sectionalizing switches. They have access to meters, power system models and load models, and perform power-flow analysis on a recurring basis to determine optimal settings of the control devices based on the utility's needs and priorities at the moment.

A DERMS-Ready DMS goes further by having the ability to include the services of DER in the math of determining of an optimal solution. Services such as dispatchable real and reactive power, ramp rate limiting and regulation provided by a DERMS can be utilized in conjunction with the conventional controls to produce overall improved responses.

The logical function of a DERMS, on the other hand, does not involve the power system model and likely does not have access to it as in the case of third-party aggregators. A DERMS may not understand why a given set of DER have been organized into a dispatchable group and likely would not know why a given service is being requested at a given time. The DMS is the part that knows why. DMS has visibility to sensors on the power system, understands it present status and limitations and knows what the operational goals and priorities are at any given time.

DMS determines what service is needed, DERMS provides the service as requested.

Some utilities envision control applications that are distributed (outside the operation center) that do have access to the power system model or a section thereof and solve it as they operate the DER in that area. This is consistent with the logical definitions provided here in that it describes a decentralized DMS. In the same way that DMS and DERMS may work hand-in hand in the operations center, they can also work hand-in-hand at distributed points throughout the power system such as at a substation. Regardless of the location, the portion that is solving the power system model is a logical part of the DMS and the portion that is aggregating, translating, simplifying and optimizing DER is DERMS. Just as in the centralized case, a distributed software or product might do both functions, but requiring exposure of the interface between the two parts limits vendor lock-in and allows other DERMS to be involved in the solution.

DERMS Ownership and Operation

Depending on their circumstances, utilities may or may not prefer to own and operate a given DERMS. Because multiple DERMS can be involved, and at multiple (nested) levels, it is not a simple binary decision. For example, a utility may have a centralized DERMS, or substation-level DERMS that they own and operate, managing a certain set of resources. The same utility may also partner with thermostat aggregators, solar aggregators and storage fleet managing entities and may tie these into utility DERMS or DMS at multiple levels.

What ownership model makes most sense depends on several factors, including the quantity and criticality of the DER being integrated. When the grid-supportive services provided by DER are merely economic optimizers, all options are reasonable. In this case the loss of a service, or its intentional misuse, would result in a sub-optimal operating condition but the grid would remain operational and customers served without interruption. However, when the quantity of DER rises to levels that are mission critical, DERMS ownership options may be narrowed as utilities are required to ensure the power system's availability and operation.

Federated Architecture for DER

The principles of DERMS presented in this paper are supported by EPRI's holistic Federated Architecture for DER Integration (FADER). This architecture is the product of a decade of DER integration research, testing and trials. The term "federated architecture" in this context refers to a system that is integrated end-to-end (e.g., from central operations to system edge) while enabling the optimal placement of intelligence throughout the system. A federated architecture is intended to "provide the highest possible autonomy in order to reduce the complexity, which at the same time shall increase what is called agility. The expected result is a high degree of flexibility — which at the end means, taking local particularities seriously and solve local problems locally whenever possible."[3]

Federated architectures are generally aimed at addressing problems with unmanageable complexity. This is fitting for the problem of DER integration with the roll-up of impacts from the device-level, to buildings, to communities, to feeders, to distribution, to transmission, to ISO. The matter is further complicated by the continuous retirement and replacement of DER over time, including connected loads, storage and generation that play roles in the operation of the grid. A management system that can effectively sustain the breadth of integration required to address this problem must be federated.

DERMS Project Examples

As noted in the introduction, utilities are finding a need for DERMS as DER levels rise and it becomes desirable to actively manage DER settings rather than leaving them fixed. DERMS active management may be manual (human operators) or automated via integration with DMS or energy markets. DERMS projects are occurring worldwide and are diverse in scale, goals, and types of DER involved. The following subsections highlight a few examples.

Arizona Public Service

April 2015 to June 2018

Arizona Public Service (APS) Solar Partner Program is assessing and advancing the use of smart inverters and energy storage in power distribution systems for:

- Managing distribution voltage at individual customer sites
- Improving power factor and reducing overall system losses
- Responding to interruptions and outages
- Adjusting power flows
- Enabling interoperability among distributed resources and existing equipment (such as capacitor banks) and controls

In 2015-16, APS deployed, and integrated with a central control system, utility-owned residential PV arrays outfitted with smart inverters on 1,598 rooftops. To better synchronize solar output with peak system demand, APS selected participants with west- or southwest-facing rooftops. The rollout was based on customer participation, focusing on select areas of the service territory. To

3 https://en.wikipedia.org/wiki/Federated_architecture

investigate the study's different use cases and underlying research questions, APS selected six feeders to be monitored and controlled as part of the research. The feeders are largely residential, with a limited number of small commercial customers that receive three-phase service. Currently, PV penetration varies significantly among the feeders, with the greatest exceeding 4MW of installed PV capacity. The study's smart inverters connect to a central control system (developed by APS and Siemens) that issues commands to individual photovoltaic systems and monitors their status.

In addition to 10 MW of new PV capacity, the Solar Partner Program deployed two battery storage systems, each rated at 2 MW/2MWh for use in peak shaving (flattening the net feeder demand) and distribution voltage management. EPRI and APS have collaborated extensively to address implementation challenges related to continuing technology development in inverters, energy storage, and control systems. The goal has been to equip APS (and other utilities) to make the best operational decisions for reliability, efficiency, and overall cost-effectiveness of their distribution system. Research questions are answered through combinations of laboratory testing, feeder modeling/simulation, field testing, and analytics.

Pacific Gas and Electric

2015 to 2018

As part of California's Electric Program Investment Charge 2 (EPIC 2) program, PG&E built a prototype system to test technical feasibility of a DERMS to coordinate DERs for distribution grid services. This demonstration project's is aimed at informing PG&E and the industry as a whole about technology and process requirements to scale DERMS technology deployments. The project is addressing the following goals:

- Evaluating the technical ability of a DERMS to coordinate DERs (directly and through aggregators) for capacity and voltage support as distribution grid services
- Clarifying DERMS requirements and characterizing barriers to deployment at scale relative to today.

The project achieved its objectives by designing and executing a range of field tests covering seven DERMS use cases, in three distribution feeders in the San Jose, CA area. To enable the testing of the target use cases, project steps included deploying DERs for the DERMS to coordinate, field verification and modeling, developing the prototype system architecture for the DERMS optimization engine, and extending protocol standards to interact with aggregations of third party-owned DERs.

The project included the following products:

- ***Residential:*** 27 Tesla behind-the-meter homes with 124 kW of PV and 66 kW/4hr of battery storage
- ***C&I:*** 3 Green Charge/Engie behind-the-meter sites with 360 kW battery storage/2 hr
- ***Utility scale:*** 1 PG&E-owned, customer-sited front-of the-meter 4 MW battery storage/7 hr. (wholesale resource)
- ***Communication System:*** Applying the IEEE 2030.5 protocol with custom extensions
- ***DERMS system used:*** GE Grid IQ

And addressed the following use cases:

- ***Situational awareness related to DER impacts on the distribution grid:*** Load unmasking to visualize hidden load
- ***Managing capacity constraints and reverse power flow***
- ***Mitigating voltage issues***: Using real power
- Mitigating voltage issues: Using reactive power
- ***Operational flexibility:*** Optimization under abnormal switching conditions
- ***Economic dispatch:*** Least-cost economic dispatch as the method for dispatching resources
- ***Dual use of DERs:*** For both distribution grid services & for wholesale energy market participation

PPL Electric Utilities

January 2017 to December 2019

PPL Electric *Utilities Keystone Solar Future* project is supported in part by an award from the DOE "ENERGISE" program to develop and demonstrate an advanced DER integration system.

The *Keystone Solar Future* project plans to pilot the central DMS/DERMS platform on select circuit in part of PPL EU's service territory to monitor and control new 3rd party assets in coordination with Company-owned devices. Through the project, PPL EU seeks to avoid uncontrollable and uncoordinated photovoltaic (PV) generation integration on the grid. The project involves:

- A centralized system fully capable of monitoring and controlling interconnected DER devices that is scalable for a sustainable high penetration solar framework
- Enhanced Distribution Management System applications for visualizing and automatically controlling DER in an intelligent way, addressing Volt/VAR Optimization (VVO), Fault Location

Isolation Service Restoration (FLISR), Advanced Feeder Reconfiguration (AFR), and islanding connection / disconnection

- Automated customer connection process to reduce the request experience timeline from a multi-day to a one-day event

The project is building on the existing PPL EU smart grid foundation.

Salt River Project

SRP's *Advanced Inverter Pilot* is a demonstration of residential and commercial scale advanced inverters for the purpose of understanding their impact on the distribution system. The project consists of three components:

- Component #1 consists of ~ 2 MW of residential PV scattered throughout SRP's service territory. Component #1 sites have an advanced function set at installation with no subsequent communication.
- Component #2 consists of 1.2 MW of residential PV also scattered throughout SRP's service territory. Component #2 sites have their settings seasonally changed via a cellular network. Settings changes are determined by EPRI and SRP based on measured data.
- Component #3 consists of 600 kW of residential and commercial PV systems connected on a single SRP feeder. Component #3 advanced settings are evaluated and potentially changed every 15 minutes via a cellular network. Settings changes are determined by a "mini-DMS" which runs a power flow analysis.

Component #1 and component #2 will reveal the realities of installing, monitoring, and communicating with large scale DER. Analytics for component #1 and #2 focus on the accuracy of inverters' reactive power functionality – i.e., do the inverters follow the command given.

Component #3 will focus on the coordination of the mini-DMS with traditional assets (capacitor banks and LTCs) and DER. The component #3 testing schedule includes times when the DMS is controlling traditional assets alone, DER alone, as well as combinations of both to understand the impact of DER compared with more well-understood distribution equipment.

Tucson Electric Power

January 2018 to July 2019

Tucson Electric Power's Project RAIN is exploring new technologies for coordinating DER for maximum benefit. This project investigates:

- the state of the industry with respect to DER aggregation
- the real-world capabilities of individual DER as well as groups
- potential for customer engagement in supporting the grid
- practical challenges of communication and coordination
- future strategies for applying DER management to TEP grid operations

Expanding on recent demonstrations of individual technologies, such as smart inverters and battery storage, Project RAIN is one of the first globally to explore how generation might be combined with flexible loads (such as electric vehicle chargers or smart thermostats) to create optimal responses to system needs. Open standards and protocols (such as SunSpec Modbus and OpenADR) will be featured in an effort to improve future system performance and reduce integration costs.

TEP and EPRI have created a set of research questions to guide the project, which will require a combination of laboratory and field evaluation to fully investigate. Several controller vendors (both established and new entrants) will be engaged as part of the process, culminating in a field evaluation of a single control system coordinating DER from multiple suppliers.

Understanding and implementing these capabilities will involve a multi-disciplinary team at TEP, bringing together staff from renewable generation, customer programs, distribution planning and operations, information technology, and cyber security.

Research Needs and Next Steps

Distribution resources, including control devices, small generators and dispatchable loads, have been connected and managed by utilities for many years, but the scale of integration and the central role that is now envisioned with DERMS is new. Available DERMS products are typically recent creations or otherwise have undergone substantial changes to position them to support smart solar inverters.

Going forward, research and evaluations are needed on a wide range of DERMS fronts:

- ***Full Realization of what DER Can Do.*** Furthering the discovery, documentation, and demonstration of new and improved ways that DER can be managed to benefit the grid and the asset owner.
- ***Improving Group-Command Execution.*** Finding through consensus, modeling and field experimentation high performing methods for disseminating group commands across the members of the group.
- ***Better Use of DER Group Services.*** Development and sharing of DMS control algorithms that make maximum use of the services that DER can provide.
- ***Migrate-ability of DER Control Algorithms.*** For both DMS and DERMS, finding open app mechanisms that enable distribution control strategies to be stored and migrated from system-to-system.
- ***Optimal Grouping of DER.*** Discovering methods for DER grouping and organization that finds the best balance between cost, complexity and performance.
- ***Learning Algorithms.*** Achieving control techniques that automatically learn from past data to refine control approaches going forward.
- ***Loss of Communication and Fallback Behaviors.*** As DER penetration levels rise, the functions carried out by DERMS are increasingly critical to operations. With this, it is important to define the behavior of DERMS and individual DER when network connectivity is lost.
- ***Matching DERMS Strategies to Communication Network Performance.*** Figuring out the latency and throughput requirements for communication systems to support given control plans. Or approached in the opposite way: figuring out what control plans are possible for a given communication system.
- ***Addressing DER Monitoring Challenges.*** Even with AMI, DER may be behind the meter and mingled with local load. In addition, a certain percentage of DER may be offline or not reachable by communication systems.
- ***Gaining Value from DER Data Analytics.*** Just as AMI systems brought volumes of data and a wide range of new analytics value, the connectivity of DER brings a new range of information that can provide value both in realtime and after-the-fact. Documentation and sharing of these analytic methods and values is needed.
- ***DERMS Integration with Other Applications.*** Beyond DMS, DERMS may interface with geospatial information systems (GIS), outage management systems (OMS), work management systems (WMS) and other utility software applications for improved value across the enterprise. How this is done, the information exchanged and the uses are not yet discovered.
- ***DER Forecasting.*** DERMS may have a role in providing more granular and more frequent forecasts of DER service capability, aiding in system optimization. How this is best handled, relative to DMS and other utility systems is unknown.

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Distribution Operations and Planning (P200)

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Electric Distribution Operations
Internal Review of PPL DER Efforts and Keystone Solar Future Project

PPL EU Distributed Generation (DG[1]) Web Portal

PPL EU has designed and implemented a customer facing web portal to enable customers to make "on-line" application to connect DG. This web portal eliminated a paper process whereby applicants were required to download pdf forms, manually complete the forms and then mail them back to PPL. Per the "paper" process, upon receipt of the paper application, various groups within PPL EU manually processed the paperwork, creating a substantial response "lag" to customers. Lags of up to 50 days were reported.

PPL's new web portal approves customer applications for DG in less than 24 hours (for customers requesting 10kW or less of DG). PPL is currently executing on an "enhanced" DG web portal that will process all customer applications for DG (any kW). Customer application data will be directly processed by PPL's distribution planning software (CYME). This capability will automate planning studies (impacts, loading, violations, etc.) to determine if the customer's request can be accommodated (hosting capacity). Additionally, the software will add all approved DG locations (and electrical data) to the electrical facilities database (GIS tool) for inclusion in their Distribution Management System (DMS) connectivity model. This is a key enabler for implementing a Distributed Energy Resource Management System (DERMS).

PPL's achievement of creating a web portal received <u>positive</u> attention from their Public Utility Commission (PUC). PPL EU wishes to be seen as an "embracer" of renewables, and is striving to eliminate processing delays to further support and enable customers who are opting to connect DG.

PPL is currently seeing a somewhat "linear" request for DG connectivity, versus the anticipated exponential growth that was expected. This is not a utility issue but rather an indication of how customer interest is leveling off in DG and how aggressive third party DG providers are successfully pursuing customers.

<u>Editorial:</u> At LGE-KU, we continue with a "paper process" for DG applicants wishing to connect to the LG&E and KU electric system. Per discussions during the Strategic Initiatives and Opportunities (SIO) workshops earlier in 2018, the topic of a similar web portal was discussed and subsequently deferred to "later". Similar to PPL EU, there is an approval "lag".

At this time, we are not experiencing any significant DER ramp-up. EDO has created a set of metrics to track DER resources installed and planned to be installed on the LGE-KU system, and will include the data in their monthly report card.

[1] PPL EU uses both the term DG and DER (Distributed Energy Resources). The terms are synonymous… In LGE-KU, we tend to use DER as is the trend in the utility sector.

PPL EU DERMS (Distributed Energy Resource Management System)

PPL EU has engaged its DMS vendor *General Electric* to commence development of a DERMS application. Software coding is in process for this capability. The DERMS "server" facilities the remote access to customer DG sites, processes the data sent/received and makes the data available for inclusion into DMS applications such as load flow, fault locating, and volt-var optimization. The current scope of the Keystone Solar project is to "pilot" nine distribution feeders and gain access to the DG connected to these feeders. Efforts are underway to gain permission from these DG connected customers to participate in the pilot. If successful in gaining such permission, the PPL EUs DMS applications will have customer DG visibility, inverter/generator output data, and ability for the DMS to control certain inverter/generator outputs (e.g. voltage set point and reactive power output). Also as part of the DERMs development activities, PPL EU has engaged *Bridge Energy* to develop a solar forecasting application in DERMs to further support operator situational awareness and load balancing models.

PPL EU has developed "royalty" agreements for the development and future sales of both the GE DERMS and Bridge Energy solar forecasting applications.

Editorial: The PPL EU DERMS initiative is a well thought out strategy, that leverages the existing capabilities of its DMS applications such as power flow, voltage control (VVO), FLISR (Fault locating, isolation, service restoration) and leverages the ancillary data input to DMS such as AMI meter data and the GIS electrical connectivity models. In comparison to the LGE-KU DMS roadmap, LGE-KU will have a nearly identical DMS capability, with the exception (for now) of AMI meter data and VVO capability. The LGE and KU roadmap plans for budgeting future dollars to implement VVO capability. EDO continues to monitor PPL's EU DERMS initiative and see it as directly applicable to LGE and KU once DG starts ramping up in the Commonwealth.

PPL EU Protection Strategy

The PPL EU Protective Relaying Engineering team has performed modeling studies on the impacts of DG contributions during fault clearing of protective devices (fuses and protective relays). A concern was identified with failing to detect blown 69 kV transformer high side fuses (DG output can mask detection.). Their team is considering alternatives to remedy the issue, including replacing high side fuses with circuit breakers or circuit switchers and using protective relays. This could be expansive, expensive, and an untimely effort.

Editorial: There are many similarities to the design of the PPL EU and LGE and KU 69 kV systems and use of high side fuses to protect transformers. Distribution and Transmission are asking to share the knowledge gained from the PPL EU protection Strategy review for applicability to LGE and KU. At LGE and KU, we have changed our design standards to use circuit breakers, however, we have many high side fuses, and many fused transformers.

As an FYI, our vendor for 12 kV reclosers (G&W) is prototyping a 69 kV recloser which could be a game changer in eliminating the high side fuse issue. LGE-KU has scheduled a factory trip with G&W in January to review the new design. PPL EU has been invited to join the LG&E and KU team on this review.

LG&E and KU Distributed Energy Strategy and Planning

In 2017, a cross-functional team was created to address, discuss, and identify solutions for DER related topics effecting LGE-KU. The team, referred to as the **DERWG** (Distributed Energy Resources Working Group) meets regularly (monthly) to assure a DER related discussion and focus is occurring. This team was the catalysts/forum for many SIO projects and recommendations identified in early 2018. For 2019, the DERWG has established an initial set of focus areas/efforts, many of which are reflective of the topics discussed relating to above discussed PPL EU efforts.

2019 LKE DERWG Ongoing Focus/Next Efforts

The DERWG will:

- Review the initial SIO business plans classified as "near term" for applicability, dispositioning, and potential funding opportunities. Per the original 32 SIO business cases, nine items were classified as "near term", including:
    - Volt/Var Optimization in DMS including smart grid capacitor and LTC controls
    - ISO/RTO Services (i.e. frequency control via battery)
    - Utility Owned and Constructed DER Sites
    - Various Communication Infrastructures
- Commence identification of new SIO opportunities;
- Review DER penetration in Kentucky, trends, forecast, LGE-KU opportunities;
- Initiate a conceptual formulation for defining and implementing a DERMS
    - Understand the PPL EU DERMS pilot
    - WPDs efforts to convert to DSO
    - WPD product offerings to manage DER
    - Track and trend other state's efforts
- Continue involvement in EPRI (P200) program on DER;
- Continue involvement in AEIC DER and Electric Technology efforts;
- Participate in Smart Cities, Solar Share, and customer DER efforts (Ford, Toyota);
- Commence dialogue and review of DER Metering Tariff opportunities;
- Consider a need to develop a customer portal for DER applications.

December 12, 2018

Western Power Distribution
Distributed Generation
August 4, 2017

Introduction

Western Power Distribution (WPD) distributes electricity to 7.8 million customers in the United Kingdom territories of Midlands, South West, and Wales.

Figure 1. WPD UK Electricity Distribution License Areas

WPD's physical assets include 220km of distribution lines and 185k substations. Their "distribution" operating voltages include:

- **LV (Low Voltage)** - in general, less than 1kV; in practice this means 400/230 V
- **HV (High Voltage)** - 6.6kV, 11kV, or 20kV
- **EHV (Extra High Voltage)** - 33kV, 66kV, or 132kV.

WPD is not involved in generating, buying or selling electricity to end use customers. Electricity is conveyed throughout the United Kingdom (UK) via the National Grid at 275kV or 400kV, for regional distribution at grid supply points (GSP).

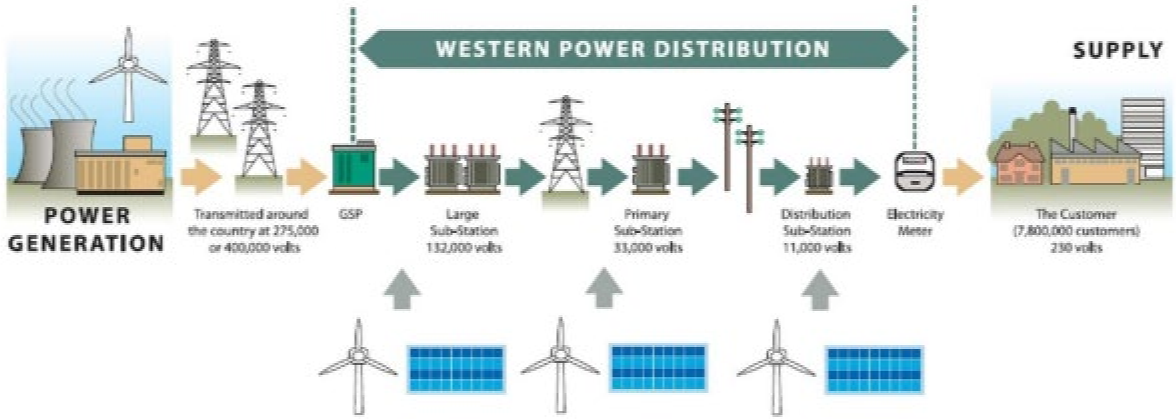


Figure 2. WPD Distribution Network Schematic

United Kingdom Electricity Value Chain

The UK electricity value chain is unbundled, and is comprised of the following components:

- Regulator - The Office of Gas and Electricity Markets (Ofgem) is responsible for regulating prices and performance in the monopoly elements of the electricity supply industry; resolving disputes between different parties when necessary; and granting licenses for the following activities in the power sector:
    - Generation
    - Transmission (and interconnection, a transmission link with another country)
    - Distribution
    - Supply
- Generators - Generators own, operate and maintain power stations which generate electricity from various legacy energy sources such as coal, gas, hydro and nuclear. Newer generation sources include wind, solar, tidal and wave.
- Suppliers - Suppliers buy electricity in bulk from generators, and then sell to consumers. They are responsible for providing bills and customer services, and arranging metering and meter reading. Electricity supply is a competitive market so you can choose and change your electricity supplier.
- System Operator (SO) - Electricity cannot be stored at a large scale and so demand has to be balanced with generation on a second by second basis by the System Operator. The SO makes requests of generators to increase or decrease output from their units, or may ask some large customers to control their demand. National Grid Electricity Transmission (NGET) is the System Operator in Great Britain.
- Transmission System - Electricity is conveyed throughout the United Kingdom (UK) via the National Grid at 275k or 400k volts, for regional distribution at grid supply points (substations).
- Transmission Owner (TO) - A TO owns and maintains the high voltage transmission system, known as the National Electricity Transmission System (NETS). Transmission Owners are responsible for making sure that transmission services are available to the SO. National Grid Electricity Transmission (NGET) is the TO in England and Wales. (Transmission costs are assessed against WPD by NGET through levying of Transmission Network Use of System

(TNUoS) charges to connected generators and users of electricity. Associated tariffs are set annually by the NGET.)

- Distribution System - The distribution system is the network that comprises the equipment between the transmission system and the customer's service switch. In England and Wales the distribution systems are the lines with a voltage less than or equal to 132 kV. WPD's costs account for approximately 16% of the domestic customer's electricity bill.
- Distribution Network Operator (DNO) - DNOs are considered monopolies which own, operate and maintain public electricity distribution networks in one or more of 14 regions in the UK. They must hold a DNO License from Ofgem. Under the terms of their license, each DNO is allowed to distribute electricity both inside and outside its legacy geographic area. There are six DNOs in Great Britain. (WPD is one of them and is licensed in four regions.) To facilitate competition in supply, each DNO is required to allow any licensed Supplier to use its distribution network to transfer electricity from the transmission system (and from Distributed Generation) to customers. DNOs charge suppliers for using the distribution system.
- Aggregators - Aggregators specialize in coordinating demand and generation (including storage) to provide demand response and other market services. DNOs and Suppliers buy demand response and other grid balancing services from aggregators.

Distributed Generation

A generating unit which is connected to a distribution network rather than to the transmission system, is considered distributed generation (DG). Prior to 1990, there were virtually no DG on UK distribution grids. Since privatization of UK distribution companies in 1990, there has been moderate growth of onshore wind and significant growth in ground and rooftop photovoltaic (PV) generation.

Generation Licenses:
Currently all generation in the UK with an export capacity of greater than 100 MW requires a Generation License. A generation license is not required if the generating source doesn't export:

- More than 10 MW;
- More than 50 MW, provided generating units have a combined declared net capacity of less than 100 MW.

Distributed Generation Tariff Structure
The UK has expressed and demonstrated commitment to sourcing 15% of its energy from renewable sources by 2020, an eight-fold increase between 2010 and 2020. To achieve this commitment the Government set out a Renewable Energy Strategy which includes financial support schemes such as a **Feed-in Tariff** (FIT) scheme for electricity installations up to a maximum capacity of 5MW, a **Contracts for Difference Tariff** (for larger generation projects), and a **Renewable Heat Incentive**.

1. Introduced in 2010, the Feed-In-Tariff scheme pays a fixed premium for every unit of electricity generated up to 5MW (or 2kW for CHP) for a set period of time (25 years for solar photovoltaics (PV), 10 years for micro-combined heat and power (CHP), and 20 years for anaerobic digestion (AD), small-scale wind, and small-scale hydro). The scheme and tariff rates are set by the BEIS.

   There are three sources of financial benefit from a generation source receiving FITs:

- Generation tariff: A fixed price for each unit of electricity generated.
- Export (supply) tariff - a guaranteed price for the export of generated electricity onto the grid;
- Import (demand) reduction - reduced electricity use from the grid, resulting in reduced customer/generator costs, due to self-generated electricity.

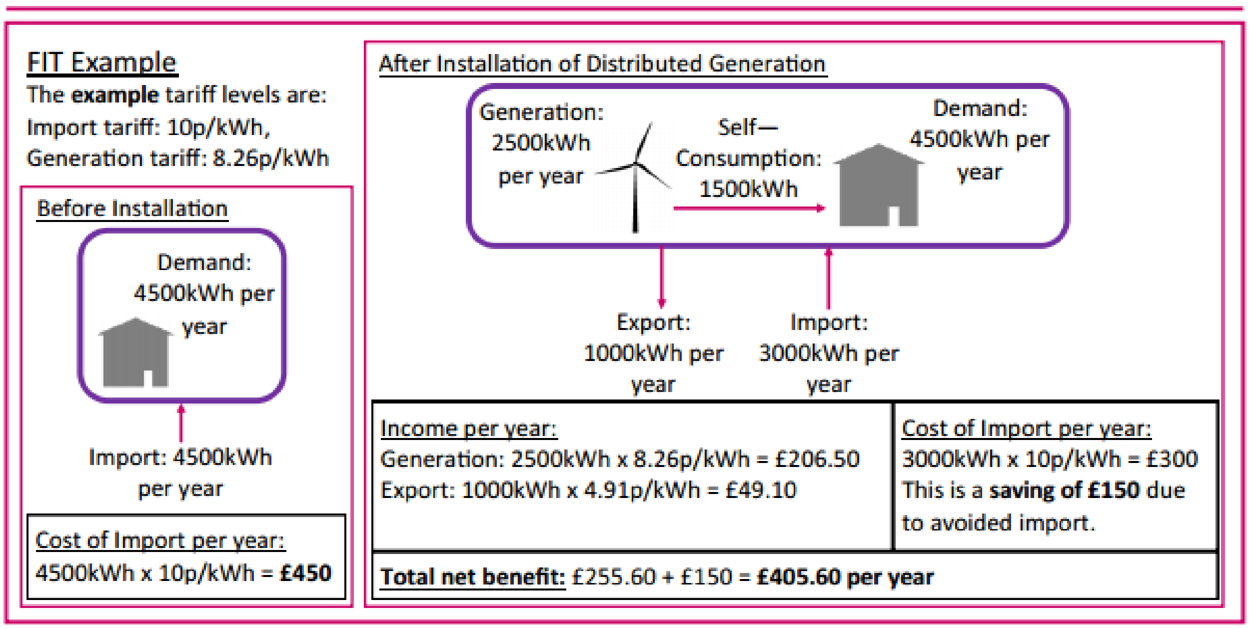


Figure 3. Distributed Generation Feed-In Tariff Example

Rates for the FIT tariffs are assessed by the Department for Business, Energy, and Industrial Strategy (BEIS) and are published by Ofgem.

FITs for PV are structured in a slightly different way. They have an accelerated digression mechanism—PV generation tariffs will change every 3 months, subject to the rate of deployment. Installations are also subject to the following criteria:

- Energy efficiency requirements—the building to which the solar PV is attached should achieve an Energy Performance Certificate (EPC) rating of level D or above for installations up to and including 250 kW; and
- Multi-installation tariffs—applies to any solar PV installation where the recipient of the FIT already receives FIT payments from 25 or more other PV installations.

2. A Contracts for Difference (CFD) tariff is the main financial incentive mechanism for larger schemes of low carbon generation. It has recently replaced a **Renewables Obligation (RO)**[1] tariff which closed to new applications in March 2017. (The RO closure does not affect generation that was already accredited before the relevant closure date.) A CFD is a bilateral contract between a generator and a Low Carbon Contracts Company (LCCC, the CFD counterparty), which is government

[1] The Renewable Obligations incentive was introduced in England and Wales during 2002; it placed an obligation on licenses electricity suppliers to source an increasing portion of electricity from renewable resources. This incentive was closed to all new generating capacity in March 2017. There were earlier closures for solar and onshore wind.

owned. A generator with a CFD is paid the difference between the "strike price" and the "reference price" for generated electricity. The strike price is an agreed upon price for electricity reflecting the cost of investing in low carbon generation. The reference price is a measure of the GB market price for electricity.

3. Renewable Heat Incentive - set up in 2012, this government incentive was initiated to promote consumption of heat by renewable resources such as biomass boilers, solar thermal, and ground source heat pumps. The RHI has two schemes - Domestic and Non-Domestic - with separate tariffs, joining conditions, and application processes. The BEIS sets the scheme policy and rules.

Distributed Generation Interconnections

DNOs are required to maintain a capacity register list for distributed generators that are connected, have enquired but not offered, have been accepted but not yet connected, or have submitted connection offers. WPD maintains their DG capacity register list on their website; each connected generator is listed with its capacity (not net capacity), generation technology, and where it connects to the WPD network. Generators that connect at HV (11kV) and below are aggregated by generation technology at their primary substation level. The following charts summarize DG connections on WPD's system.

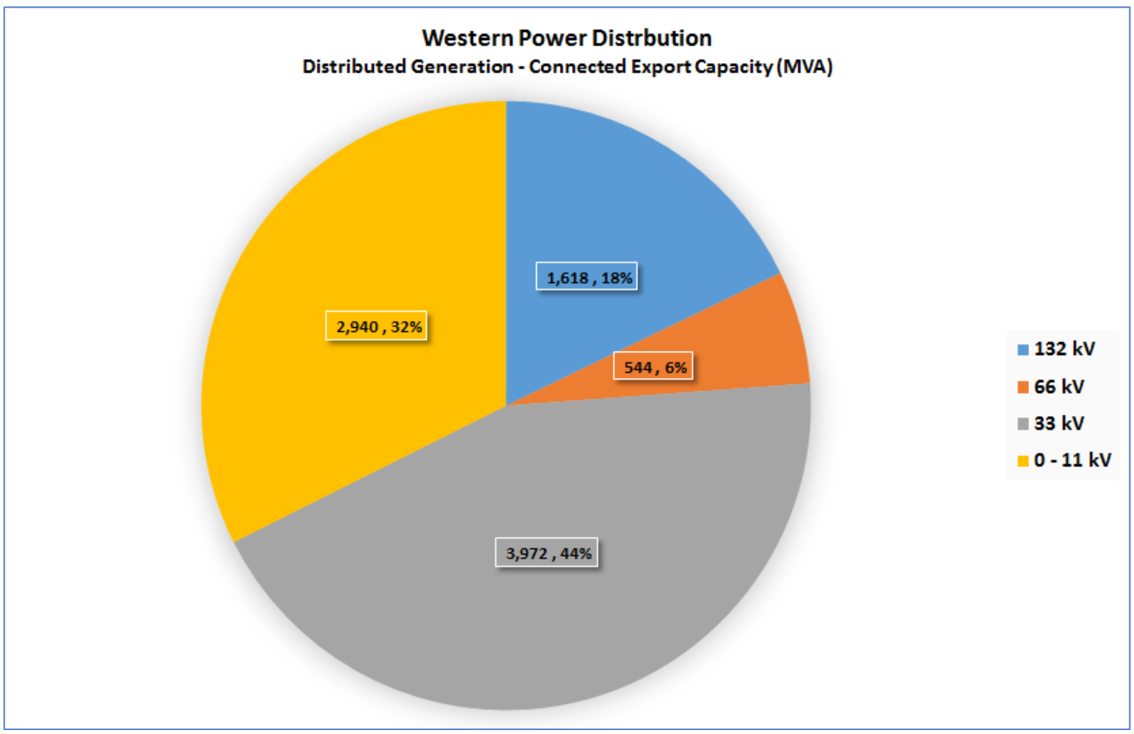


Figure 4. WPD Q3 2017 Connected Distributed Generation Composition by Voltage

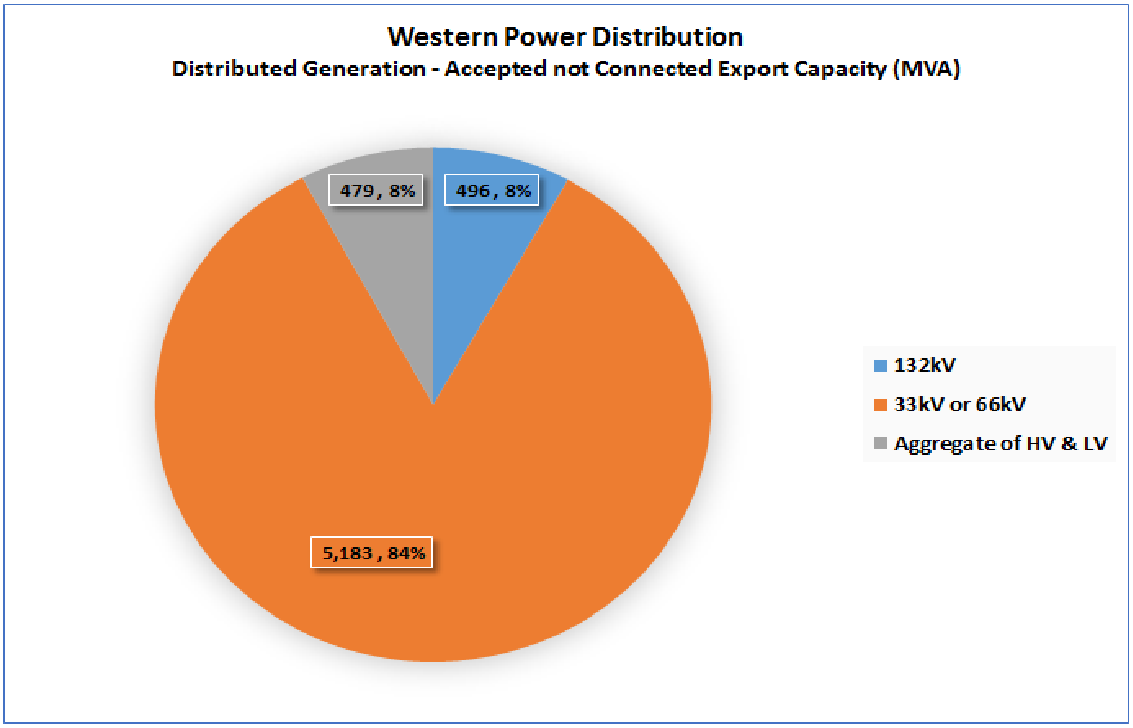


Figure 5. WPD Q3 2017 Accepted Not Connected Distributed Generation Composition by Voltage

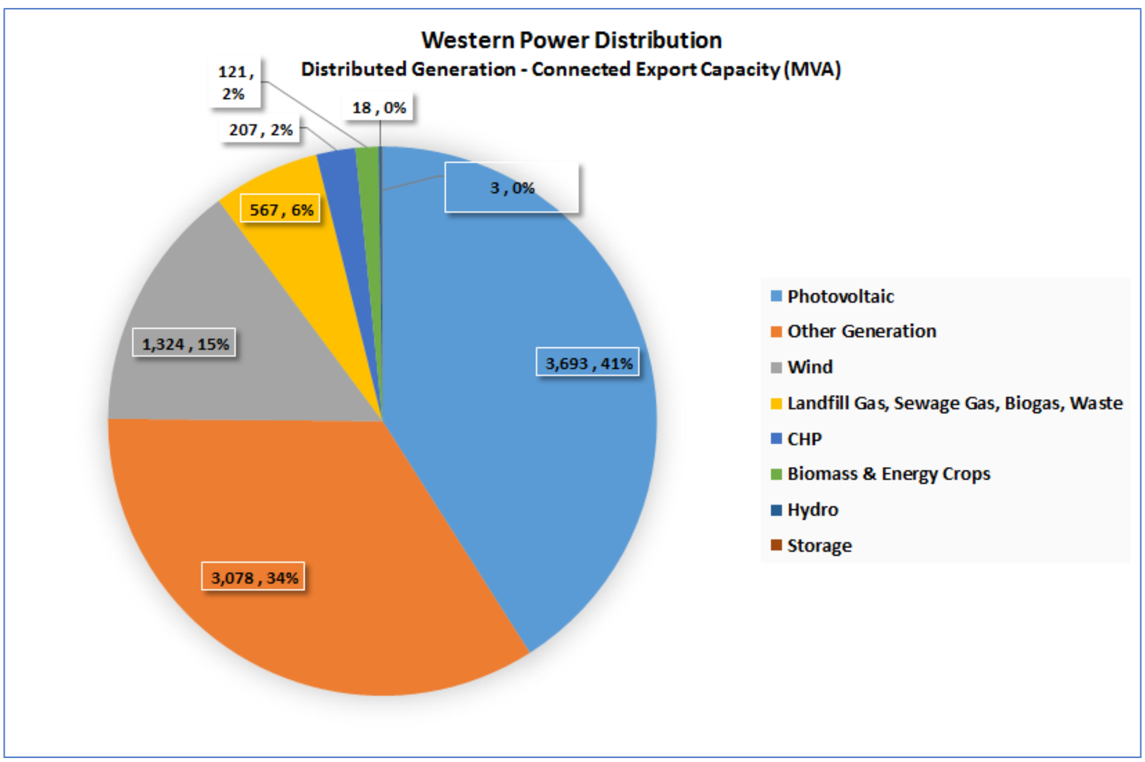


Figure 6. WPD Q3 2017 Connected Distributed Generation Composition by Type

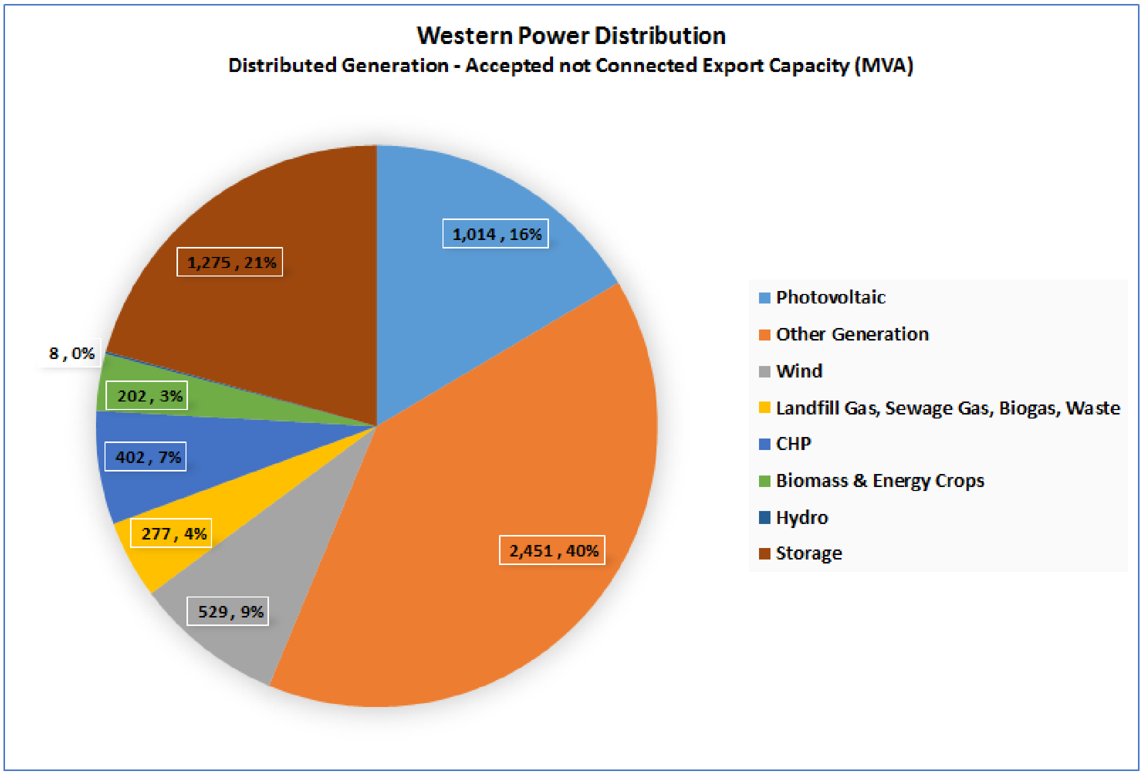


Figure 7. WPD Q3 2017 Accepted Not Connected Distributed Generation Composition by Type

The next two tables were pulled from a public WPD report on strategic investment options for growth of demand. Figure 8 depicts the ratio of connected and accepted distributed generation to 2016 system demand for WPD's four distribution license areas. Figure 9 depicts WPD's total and renewable energy distributed for 2016.

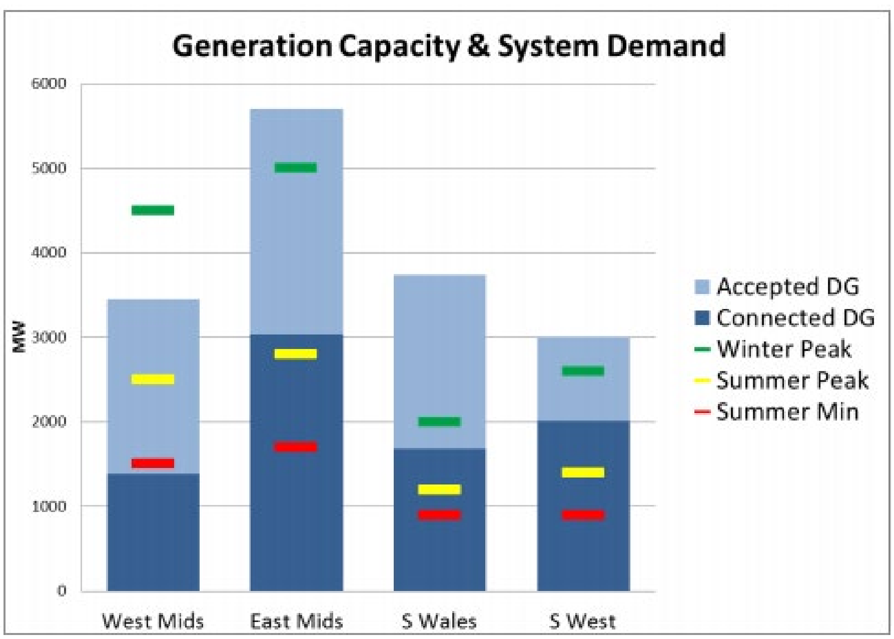


Figure 8. WPD 2016 Generation Capacity and System Demand

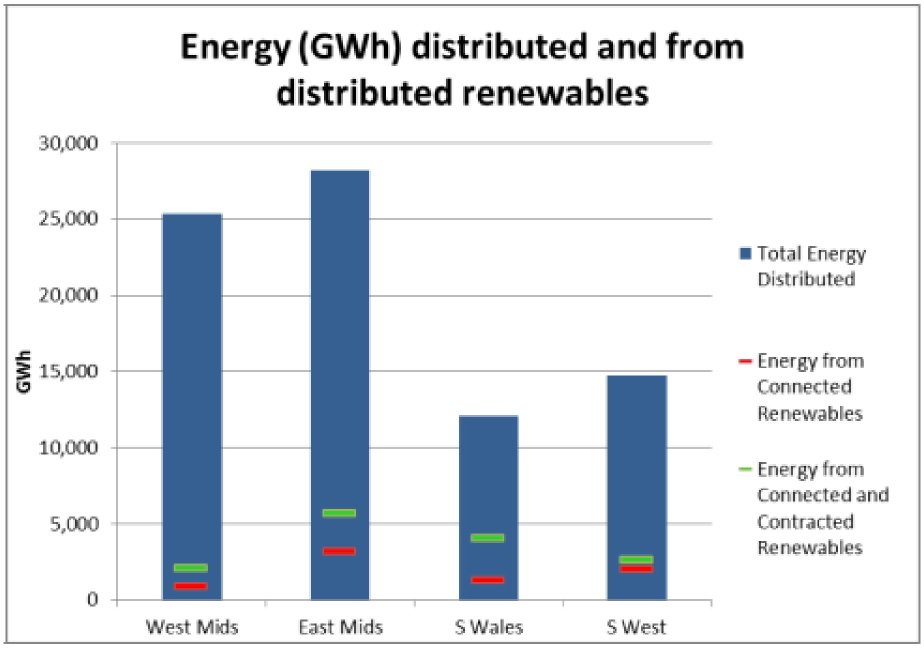


Figure 9. WPD 2016 Total Energy Distributed

The Energy Networks Association (ENA) is a trade association in the UK that represents wires and pipes transmission and distribution network operators (DNOs) for gas and electricity in the UK. The association has developed distributed generation interconnection guides for UK customers, generators, and DNOs.

- **(G83)** Domestic scale generation - for single or multiple premise households
- **(G59)** Small (50kW of less 3-phase) or Large (larger than 50 kW) scale generation - for developers, industry, commercial, or famers

Figure 8 contains a table provided in the ENS DG interconnection guides which specific guide sections, license requirements, incentive schemes, and connection process based on generator size.

Under the SNA Guidelines, <u>Suppliers have the main customer-facing role for distributed generation under the FIT scheme</u>. They register eligible installations, process generation data, and make necessary payments.

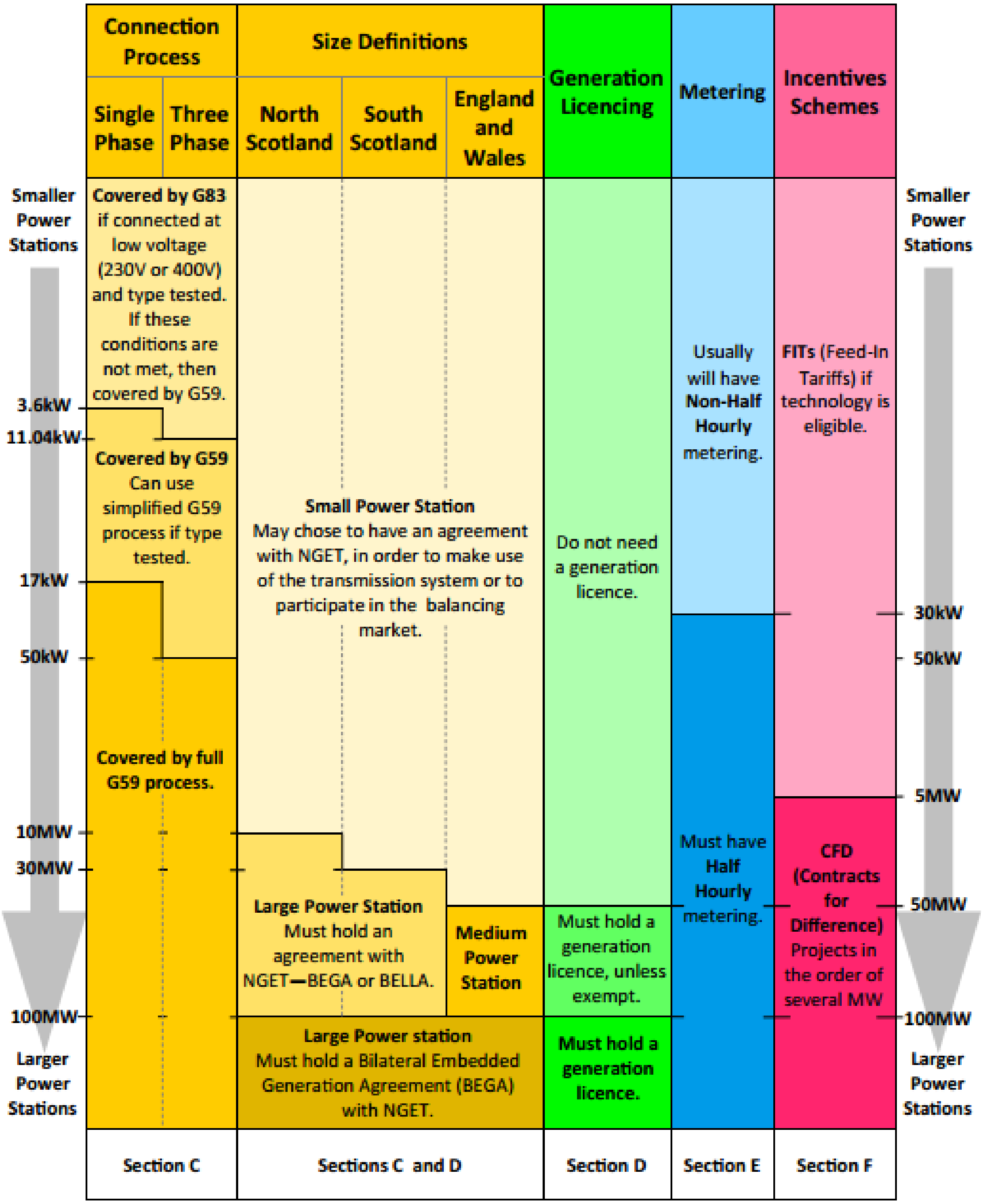


Figure 10. Electricity Networks Association Distributed Generation Connection Guide

<u>Distributed Generation Applications</u>

Upon receiving an application for distributed generation, a DNO may request NGET to assess the impact of proposed generation on the transmission system. This Statement of Works process indicates what, if any, work needs to be carried out on the national transmission system as a result of initial assessments by NGET. As a result of a SoW assessment, NGET may impose conditions on the DNO regarding the proposed distributed generation connection. These conditions would be captured in a Connection Agreement between the DNO and prospective DG proponent. The DNO would be required to secure any financial sums payable to NGET for any required work on the transmission system.

WPD maintains a customer interactive map on their homepage to assist customers and generators with determining where system capacity or constraints exist for distributed generation interconnection. (See Figure 11.) According to the website, generation headroom is calculated using up-to-date statistics incorporating connected, accepted but not yet connected, and quoted generation figures. Red markers on the map indicate locations where grid improvements would likely be necessary to facilitate interconnection of additional generation.

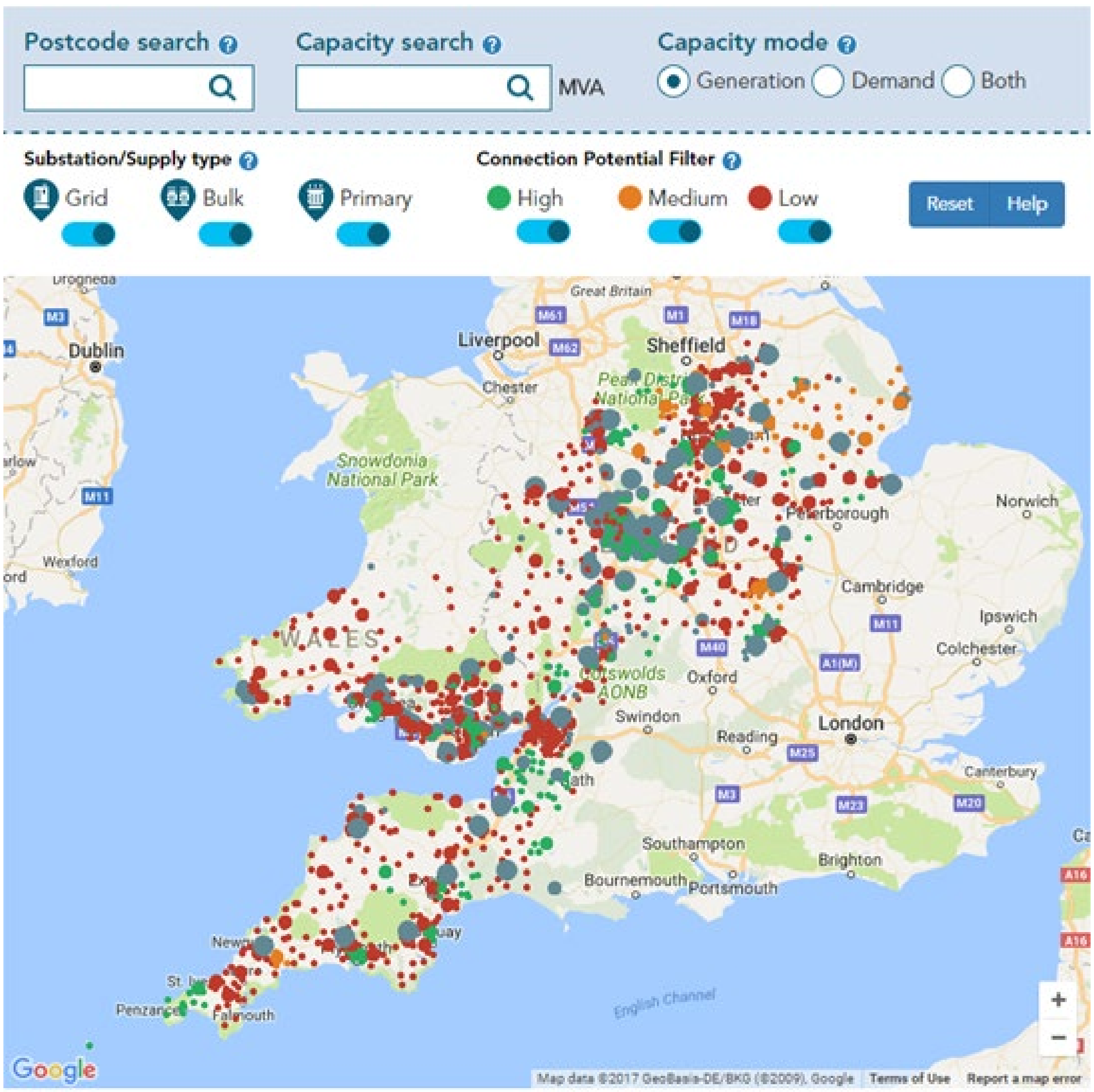


Figure 11. WPD Distributed Generation Potential

The Standard Conditions of an Electricity Distribution License require DNOs to offer terms for DG connection and use of system "as soon as is reasonably practicable" after receiving a request. If a DG customer only requests for Use of System, the DNO must provide an offer within 28 days. If a DG customer requests both Connection and Use of System, the DNO must provide an offer within three months.

<u>Distributed Generation Charges</u>
There are two categories of charges made by a DNO to distributed generators:

- Connection charge - this is a one-off charge made by the DNO, which primarily covers the costs of work and equipment associated with connecting a generating project to the distribution network.
    - New infrastructure
    - <u>Some</u> reinforcement of the existing infrastructure

  Note, the BEIS governs electricity connection charges regulations (ECCR) to assure fair distribution of connection costs.
- Use of System (UoS) charges - these are ongoing charges, which primarily cover operation and maintenance costs and include an element to cover the costs of ongoing network development including general reinforcement:
    - Distribution UoS charges
    - Metering charges
    - Top-up and standby charges
    - NGET transmission UoS charges

  All generators with equipment connected at LV and HV are subject to UoS charges under the Common Distribution Charging Methodology (CDCM) established by Ofgem. (DNOs are mandated to publish a document on their website which describes the basis of connection charges and charging methodology).

<u>Distributed Generation Metering</u>
Metering of distributed generation generally falls into one of two categories:

- Half Hourly Meters (HH) - required for large distributed generators, with generating capacity greater than 30kW; these units measure and record energy passing through the meter for each half hour period; associated data is collected remotely every day.
- Non-Half Hourly Meters (NHH) - generally required for smaller distributed generators; meter records total energy passing through the meter, but do not record the times energy is transferred; meters are the responsibility of the supplier (meter operator, data collector, data aggregator)

<u>Distributed Generation Challenges</u>
Rapid connection of DG to the UK electric grid has resulted in constrained transmission and distribution line segments, necessitating substation capital investment or technology innovation to sustain system reliability and integrity. Examples of the challenges posed to distribution networks by DG include:

- Distributed Generation changes the current flows and shape of the load cycle where they are connected. This could cause:
    - Thermal ratings to be exceeded.
    - System voltage to rise beyond the acceptable limits.
    - Reverse power flows, i.e. power flows in the opposite direction to which the system has been designed.
- Distributed generation can contribute to a fault level which can raise the fault level above network equipment ratings.
- Power quality limits that can be affected by Distributed Generation, including:

- Contributions to harmonics, particularly if a significant number of invertor controllers are present;
- Voltage unbalance which affects power quality, if there are a significant number of single-phase generating units; and
- Voltage fluctuation or flicker, due to rapid changes in distributed generation output.

During benchmarking with WPD, their representatives indicated that none of the referenced challenges have resulted in significant engineering or operational issues for WPD. However, some DG interconnection requests have been delayed to enable WPD or NGET to mitigate system constraints (capacity, voltage, or thermal) on their grid systems.

<u>Technology Innovation Fueled by Distributed Generation</u>
In areas where there are multiple complex system constraints on the distribution system, affecting a number of customers over a long time period, full active network management (ANM) systems are being offered to customers. Distributed control systems continually monitor all the limits on the network and then interactively allocate the maximum amount of capacity to customers in that area, based on the date their connection was accepted.

A Last In, First Out (LIFO) hierarchy is used to prioritize the oldest connections when issuing capacity, but is scalable so that new entrants will get access to the capacity when it becomes available.

Western Power Distribution
Distribution Generation and Distribution System Operator (DSO) Review
May 2019

General Observations

1. **Distributed Generation**
    - **a.** Rapid growth of distributed generation was driven by Feed-In Tariffs and Regulations which support lower carbon emissions and technologies.
    - **b.** As greater penetrations of DG occurred on WPD's grid, WPD could not keep pace with making the necessary changes to their grid to accommodate the additional generation, resulting in extended durations to accept interconnection requests.
    - **c.** As a Distribution Network Operator, WPD is generation agnostics, and maintains responsibility for distributing safe and reliable (SAIDI-29 minutes, SAIFI-0.5) electric service.
2. **Flexible Power Services (FPS)**
    - **a.** FPS offerings were developed to help manage known or forecasted system constraints associated with load/generation peaks, maintenance outages, and system emergencies.
    - **b.** FPS generally provide temporary alternative(s) to infrastructure investment needs, and are leveraged particularly where WPD cannot build infrastructure quickly enough to keep up with DG requests and load growth (electrification of vehicles). Concept is very similar to Non Wires Alternatives being touted/deployed in the Unites States (New York – REV).
    - **c.** WPD continues to pilot other "innovation" services, including a market based platform as an alternative to their Flexible Power Services offerings.
3. **Distribution System Operator (DSO)** – WPD continues to advance DSO capabilities which provide for management, monitoring and operations of distributed energy resources on their distribution grid.
    - **a.** Initially, WPD positioned DSO functions within their Distribution Control Center, taking advantage of personnel with experience utilizing Advanced Distribution Management Systems. As their DSO model continued to develop, WPD separated DCC and DSO functions, but maintained them under a common senior management structure.
    - **b.** WPD's strategy is to demonstrate their unique DSO capabilities to their Regulator, with the goal of maintaining full control of their network operations, and limiting/preventing system operations access to any third parties.
    - **c.** WPD's system planning processes, analytics, and tools needed to be enhanced to provide for more granular and real time understanding of system operating and customer load/generation characteristics.
4. **Data Analytics and Innovation –** WPD is incentivized by their regulator to deploy innovative solutions which benefit customers.
    - **a.** Focus has been placed on hiring an increasing numbers of engineers and data analysts to advance innovation and build analytics around the distribution system and customers.
    - **b.** Individual customer meter data is not available to WPD. Data analytics tools have been/are being developed which enable WPD to leverage aggregated data, from a number of data sources on their grid, to develop customer load/generation and system power flow reports which aid in system planning, innovation program design, etc...
5. **Vegetation Management** – WPD is outfitting their helicopters with lidar, infrared, corona cameras and HD video and using artificial intelligence to review all of that data to find problems that need to be addressed.

Company Opportunities

1. **Proactive versus Reactive Approach –** WPD acknowledges and regrets not being prepared for the rapid deployment of DG and associated system impacts, and suggested that LG&E and KU should aggressively prepare for a future with greater penetrations of Distributed Energy Resources (DER).
    - **a.** Educate and influence regulators. Convince Regulators that the Company desires to be an enabler and not a "blocker" of distributed energy resources. Prepare organization to demonstrate unique ability to be DSO, and accommodate integration of DG efficiently.
    - **b.** Prepare the electric distribution grid.
        - **i.** Conduct distribution system hosting capacity analysis to understand where the system can and cannot accommodate DG. Develop plans to add capacity which potentially encourages/influences where DG is deployed. (Similar to Economic Development strategies)
        - **ii.** Continue to advance system intelligence and automation, which enhances ability to perform key DSO functions.
    - **c.** Advance business processes.
        - **i.** Improve DER interconnection request processes, including development of an electronic application and approval process.
        - **ii.** Advance system planning processes to include greater analytics around forecasts, with input from key government, developer, and investor communities.
    - **d.** Advance Data Analytics and Innovation.
        - **i.** Focus hiring strategies on hiring engineers and data analysts/scientists to provide for greater innovation.
        - **ii.** Advance AMI to enable greater situational awareness and analytics around customer and system operating characteristics.

LG&E and KU Strategies Aligning DSO Model

1. **Centralized Grid Operations Strategy**
    - a. Establishment of Single Distribution Control Center (May 2019)
    - b. Deployment of Advanced Intelligence on the Distribution Grid (ongoing)
        - i. Electronic SCADA Capable Reclosers (ongoing)
        - ii. Expansion of SCADA in KU Substations (ongoing)
        - iii. Deployment of Distribution SCADA for DA (ongoing)
        - iv. Accelerated Replacement of Electromechanical Relays with Microprocessor Based Relays (ongoing)
        - v. Deployment of Intelligent Capacitor Controllers (ongoing)
        - vi. Deployment of Invertor Control Technology (future)
    - c. Deployment of an Advanced Distribution Management System – Ongoing
        - i. Fault locating (ongoing)
        - ii. FLISR (ongoing)
    - d. Implementation of Advanced Applications/Tools
        - i. Real Time Outage Management Detection (future - AMI)
        - ii. VVO (future)
        - iii. CVR (future)
        - iv. DERMS (future)
    - e. Advancement of Employee Skill Sets
        - i. Technical Skills versus Operations/Field Experience (ongoing)
        - ii. System Operator versus Dispatcher (ongoing)
        - iii. Troubleshooter (ongoing)
    - f. Establishment of Communications Center (NOC)

i. DER communications (future)
ii. AMI communications (future)
iii. All back-haul monitoring (future)
iv. Wireless systems (future)

2. **System Planning**
   a. Distribution hosting capacity (future)
   b. Bi-directional power flow (relaying challenge) (future)
   c. Customer behavior analytics (future)
   d. NWA solutions (future)
   e. DER net-metering “hidden load” modeling (future)
3. **Customer Service**
   a. DER portal (future)
   b. Financial/Commercial Service Offerings (like “Flexible Power”) (future)

Update an EPRI DER-Related Projects

Jeff Smith
Senior Program Manager
Distribution Operations, Planning, and Studies

AEIC DER Sub-Committee Meeting
2/28/2018

Point Clear, AL

Overview – Highlight of Recent Activities

Analyzing Impacts of DER (DRIVE)

- Automating hosting capacity analytics
- Automating DER mitigation analytics

Interconnecting DER

- Navigating DER interconnection standards and practices

Operating with DER

- Net-metering impacts on operations
- Defining the role and function of DERMS
- Advanced operational solutions with DER

Protecting the Grid with DER

- Anti-islanding solutions and practices
- Characterizing DER for fault/event modeling
- Protection Interest Group/Task Force Meeting

Planning for DER

- Guidance on DER portfolios as non-wires solutions
- Distribution planner role of the future
- Evolution of the planning process

Analyzing the Impacts of DER

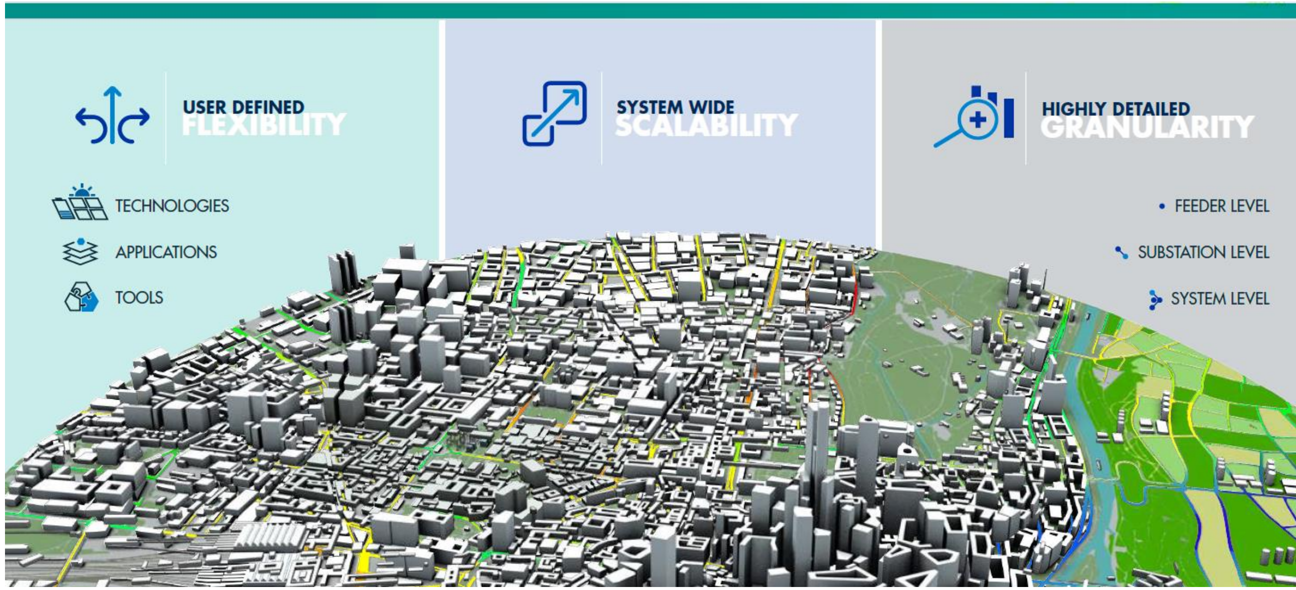
Automating hosting capacity analytics

Automating DER mitigation analytics

What is DRIVE?
Distribution Resource Integration and Value Estimation Tool

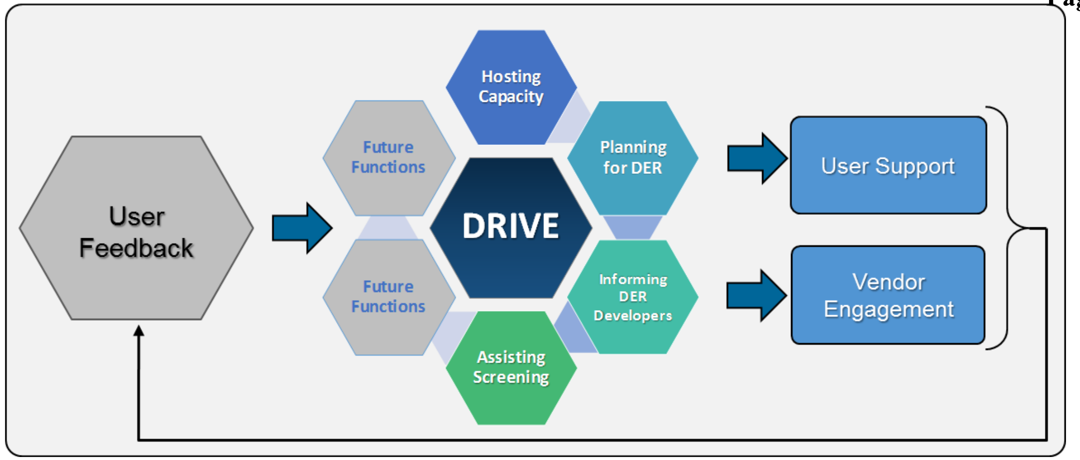
Enables planners to efficiently and effectively evaluate the technical impacts of DER on distribution systems

- Capabilities
  - Voltage, thermal, and protection analysis
  - Multiple DER technologies
  - Location-specific, node-by-node analysis
  - Automated, distribution system-wide analysis
- Applications
  - Hosting Capacity
  - Planning with DER
  - Informing DER developers
  - Assisting interconnection screening
- Compatibility
  - Existing planning tools (CYME, Synergi, Milsoft, OpenDSS, etc.)



DRIVE User Group

- Implementation & release of future enhancements
- Support & forum for users
- Application experience collaboration/sharing
- Opportunities to message consistently across states



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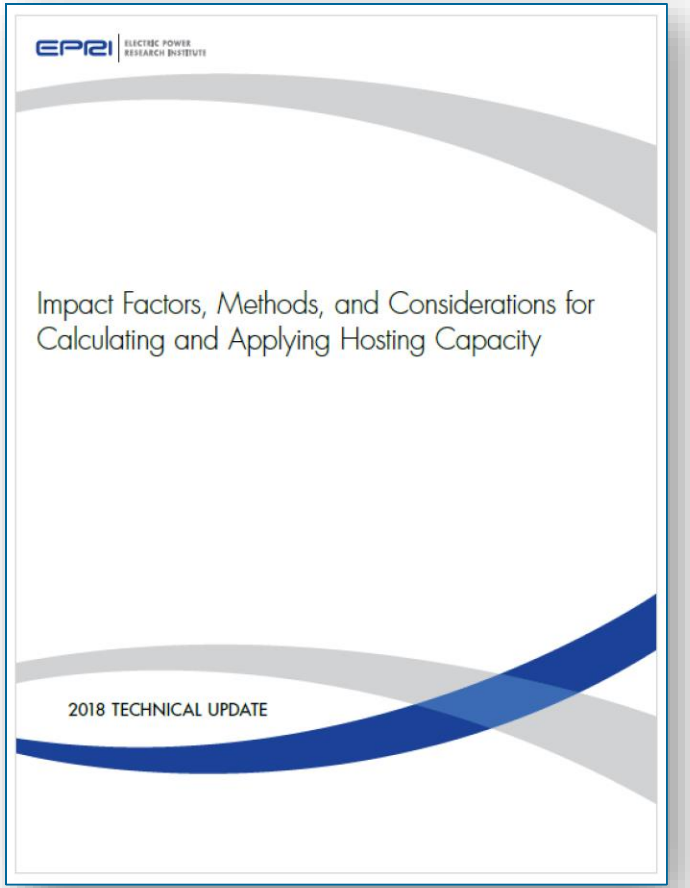
Recent Highlights in 2018

- Considerations for applying hosting capacity
  - Challenges
  - Clarification around methods
  - Recommended applications
- Comparison of Results
  - California Iterative ICA
  - DRIVE
- DRIVE Enhancements
  - Improved accuracy
  - User group requests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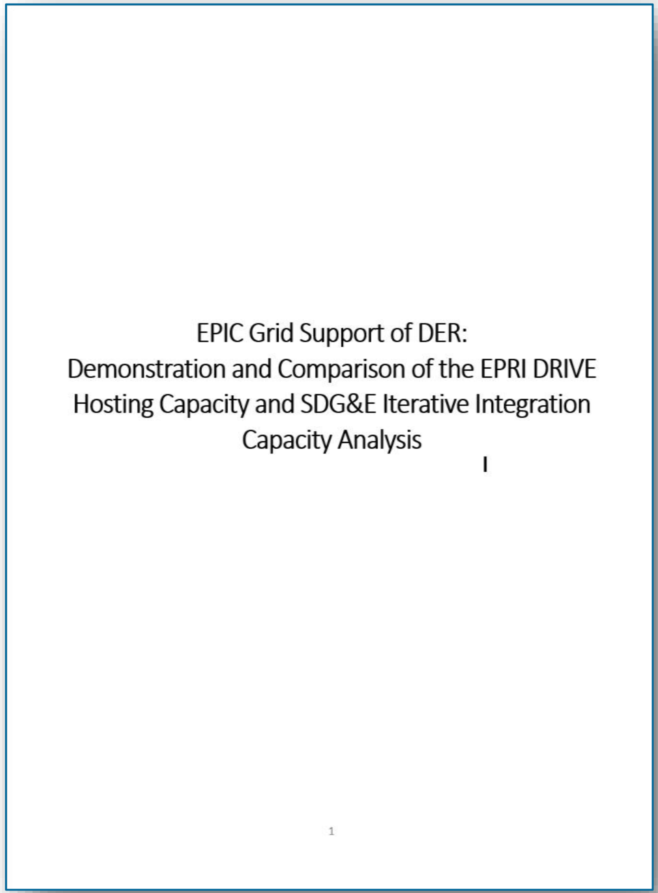
Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity

2018 TECHNICAL UPDATE

Link to Report


EPIC Grid Support of DER:
Demonstration and Comparison of the EPRI DRIVE Hosting Capacity and SDG&E Iterative Integration Capacity Analysis

1

Report available in coming days

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Automating DER Mitigation Solution Assessments

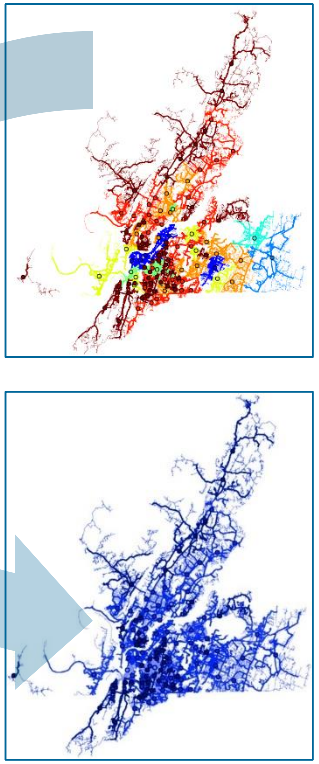
- **Utility Challenge**
  - Methods for increasing hosting capacity depend on many factors
  - Most effective and least-cost integration solutions are unique
  - Current mitigation evaluation is time-consuming and on a case-by-case basis
- **Project Objective**
  - Develop methods to assess mitigation solutions – grid side and technology
  - Implement methods in DRIVE for system wide assessment

NEW YORK STATE OF OPPORTUNITY. | NYSERDA

Integration Solutions to Increase Hosting Capacity

	Mitigation Solution	Hosting Capacity Violation: Voltage	Thermal	Protection
Grid-Side Enhancements	Reconductoring	Yes	Yes	No
	Voltage uprating	Yes	Yes	Yes
	Transformer replacement	Yes	Yes	Maybe
	Additional voltage regulator	Yes	No	No
	Comm/control (curtailment)	Yes	Yes	Maybe
	Additional relaying	No	No	Yes
Operational Changes	Voltage regulation changes (LTC adjustment, etc.)	Yes	No	No
	Relay setting modification	No	No	Yes
Technology Solutions	Smart Inverter (var control)	Yes	No	No
	Smart Inverter (watt control)	Yes	Yes	Maybe
	Distributed var control	Yes	No	No
	Energy storage	Yes	Yes	Maybe
	PV panel orientation	Yes	No	No
	Demand response	Maybe	Maybe	Maybe

Yes | No | Maybe



New methods will allow utilities to…

1. **Simplify mitigation assessment process**
2. **Automatically identifying least-cost solutions**
3. **Identify opportunities to increase hosting**

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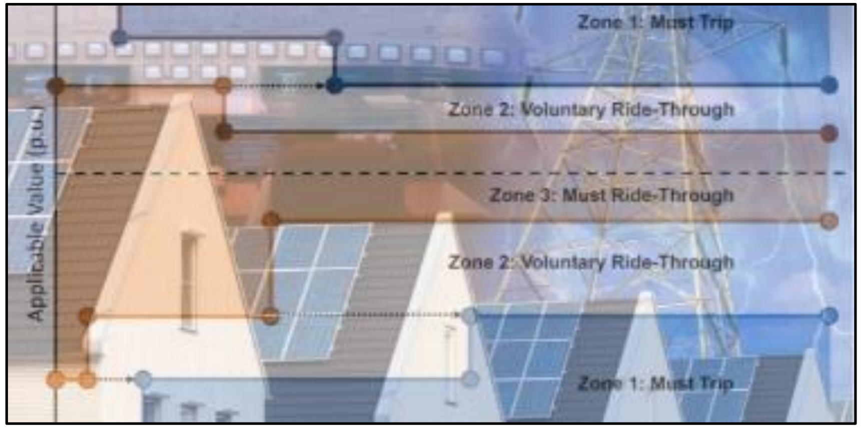
Interconnecting DER

Navigating DER interconnection standards and practices

Navigating DER Interconnection Standards and Practices

Supplemental Project Summary

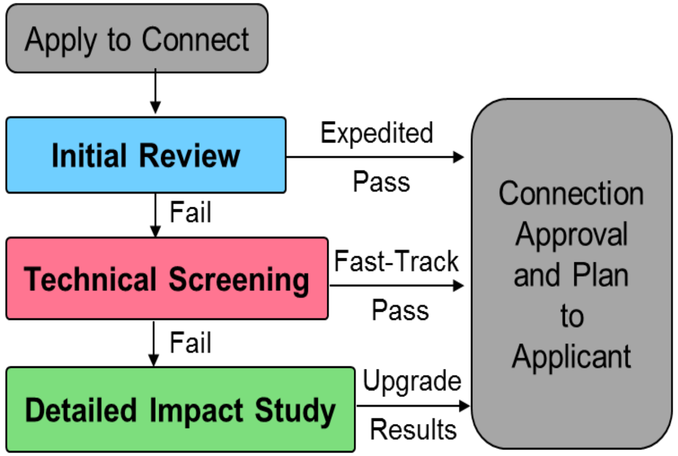


Objectives and Scope

- Support utility-specific application of new IEEE Std 1547 interconnection requirements for DER
- Provide insights into interconnection leading-practices and procedures.

Value

- Adopting requirements: Assistance for adopting new DER interconnection requirements to meet utility/regulatory needs.
- Streamlining interconnection: Strategies for effectively streamlining DER grid connection processes.



Coordination between distribution and transmission planning.

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"Navigating DER" *Proposed Project Approach*

Participation in First Part

Transmission Planners + Distribution Planners

Part I Scope. Support Staff Development to Apply New IEEE Standards

Member-specific training webinars → **Member-specific recommendations** → **Multi-member workshop** | **Member-specific training workshop** *Optional*

Member-specific training webinars

- Requirements (1547)
  - Performance category assignment
  - Grid-specific tuning of DER settings
  - Communication protocols
- Verifications
  - Interim solution UL1741(SA) vs. mid-term solution IEEE 1547.1
  - Type tests vs. composite DER
  - DER evaluations vs. utility screening methods
  - Commissioning testing

Member-specific recommendations

- Evaluate member needs and input
- Address specific challenges, e.g., extended ride-through versus anti-islanding detection
- Recommend next steps considering unique needs for application of new 1547

Multi-member workshop

- Share experiences and learnings of participants
- Identify leading interconnection practices

(workshop includes both the participants in Part I and II

Member-specific training workshop (*Optional*)

- Tailored in-person workshop covers:
  - Application of 1547 in utility-specific context
  - Support and input to inform regulatory proceedings

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"Navigating DER" *Proposed Project Approach*

Participation in both parts I and II

Distribution Planners (only)

Part II Scope. Improving Utilities' DER Interconnection Practices

Member-specific meeting assessing interconnection practices, gaps, opportunities → **Member-specific report re: current practices, alignment w/leading practices** → **Multi-member summary of findings and leading practices** → **Multi-member workshop (Part I+II learnings)**

Note: All Part I scope included in Part II

- Project Objective
  - Investigate, analyze, document current status of utilities to manage interconnections
  - Examine opportunities to further streamline processes and/or design, develop, implement an online interconnection portal
- Approach
  - In-person interviews to gather information
  - Perform streamlining assessment
  - Document findings, present opportunities for improvement

Initial Inquiry
⇩
Inquiry Review
⇩
Application Review
⇩
Installation
⇩
Verification/Testing
⇩
Final Acceptance

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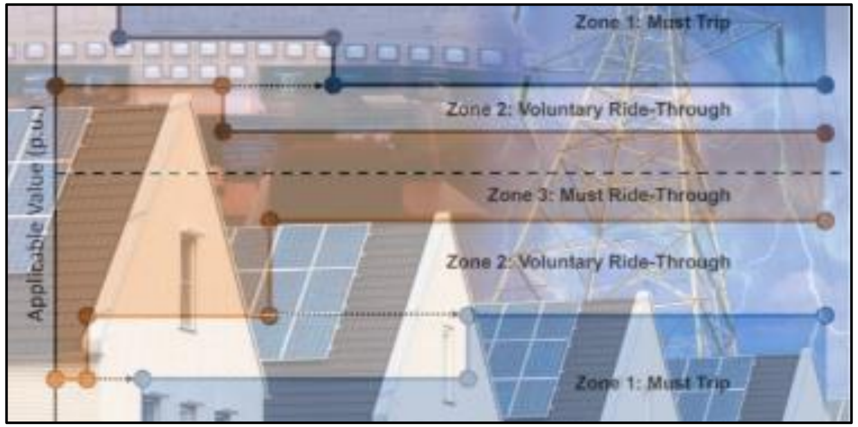
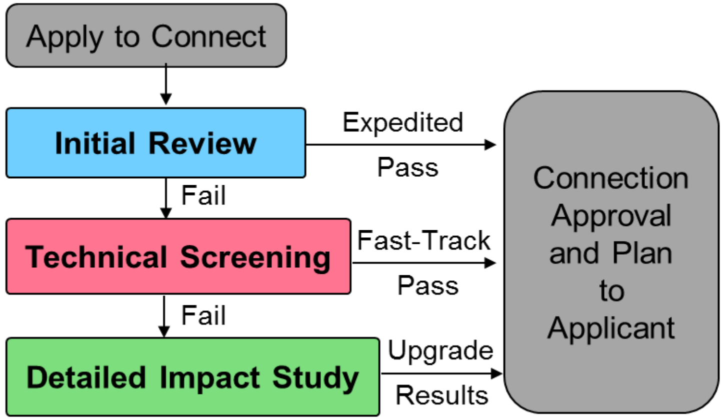
Navigating DER Interconnection Standards and Practices

Supplemental Project Summary



Project Scope

- Conduct member-specific training on changes to and application of 1547/1547.1.
- Based on utility input, develop recommendations for considering new options, technical req'ts, and responsibilities posed by 1547.
- Interview utilities to document interconnection processes, assess gaps, and ID opportunities for improving application mgmt. and technical review procedures.



Details and Contact

- Part I Applying IEEE 1547 for Interc. Agreements: $35,000
- Part II DER Interconnection Practices (incl. Part I): $65,000
- Part III (*Optional*) Utility-specific Workshop: $15,000

Timing: 2018, 12-24 mos.; 5-8 member min. ✓, kick-off: Feb.

Jens Boemer and Nadav Enbar

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- nenbar@epri.com, (303) 551-5208

SPN Number: 3002012048

Coordination between distribution and transmission planning.

Operating with DER

Net-metering impacts on operations

Defining the role and function of DERMS

Advanced operational solutions with DER

White Paper: Balancing DER Metering Requirements & Grid Mod

- **Objective**
  - Outline the need for reevaluating DER metering requirements and the importance of balancing this with future grid operational needs
- **Overarching Themes**
  - Existing requirements that are basis of metering decisions today were not driven by technical requirements of distribution ops
  - Visibility into where DER is and what it is doing is required to make best use of grid mod investments
  - Industry must look holistically for DER to be a full participant

Industry Questions

What level of visibility is needed as grid automation increases?

Is net metering sufficient for effective grid support?

What's the best way to monitor if DER is to be an active participant?

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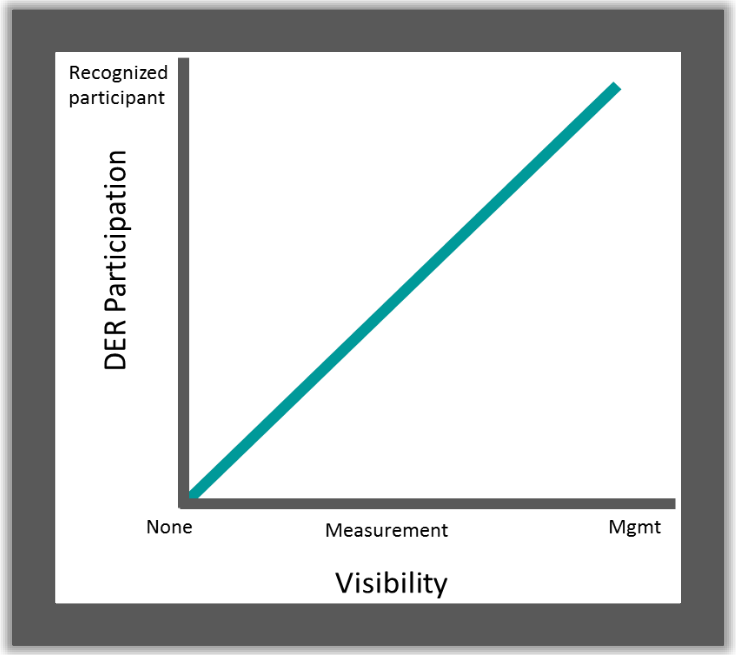
High-Level Draft Outline

- Current Trends and Realities
  - DER on rise
  - Utilities/states have different metering approaches
  - Grid modernization is on the rise
- Risks of the Status Quo
  - Need to get ready to employ DER
    - Relationship of monitoring & management
  - Need for change as DER becomes grid participant
    - DA deployments can be stymied or not optimized
    - DMS optimization can be limited
    - DER participations can be limited
- Summary of Recommendations



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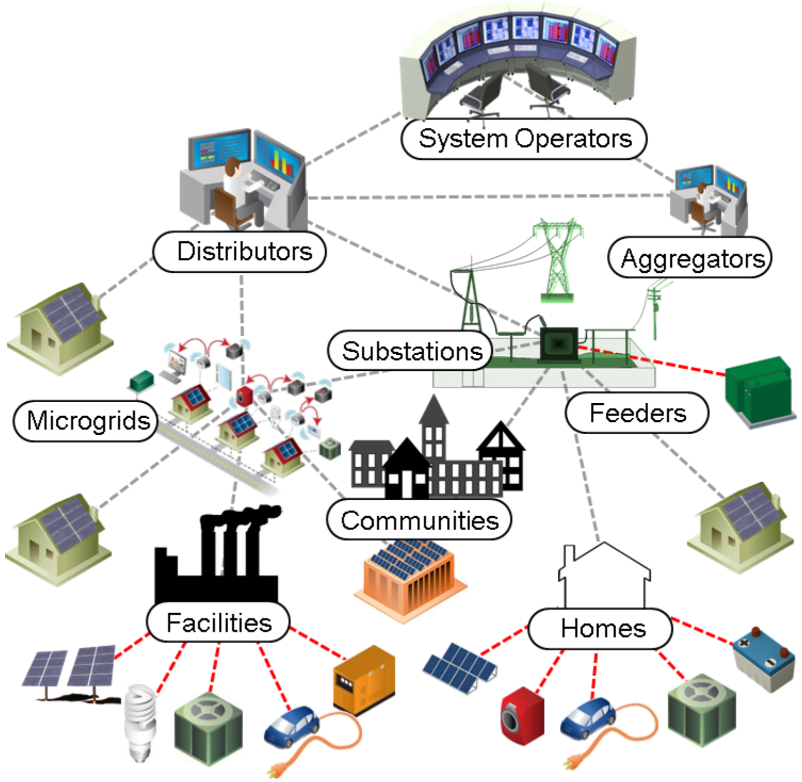
Understanding DER Management Systems (DERMS)

Utility Need
- DER is being deployed rapidly throughout the distribution system
- The need for a solution to manage these assets is apparent

Research Objective
- Fully document what a DERMS is
- Fully document what a DERMS is NOT
- Document how DERMS fits in to Distribution Operations

Member Value
- Clear definition of DERMS to reference when acquiring a DERMS
- Eliminate confusion that presently exists in the industry

Plan for 2018
- Develop clear focused definitions of DERMS
- Compare / contrast with other definitions



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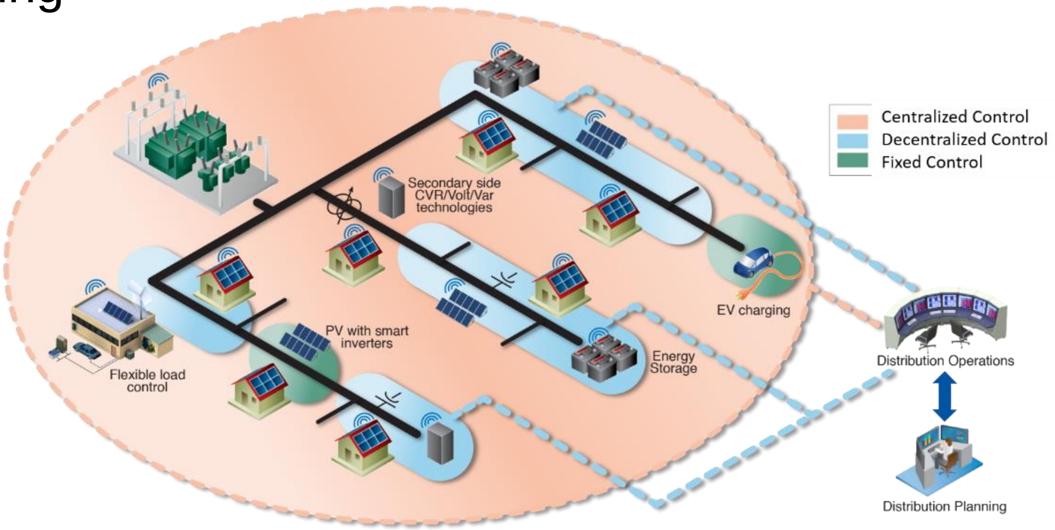
Advanced Operational Solutions with DER

- **Objective**
  - *Develop advanced operational analytics and control algorithms for high pen DER*
  - *Demo hybrid control solutions coordinating existing assets with DER*
- **Approach**
  - Develop adv algorithms to incorporate DER in ops, including measurement & management, VVO/FLISR
  - Coordinate resource utilization using hybrid control
  - Demo effective solutions & control strategies
  - Document lessons learned controlling DER with DMS
- **Outcome**
  - Innovate & develop new control methods & algorithms
  - Demo new control method
  - Identify challenges, gaps, & solutions for DMS applications



Protecting the Grid with DER

Anti-islanding solutions and practices

Characterizing DER for fault/event modeling

Protection Interest Group/Task Force Meeting

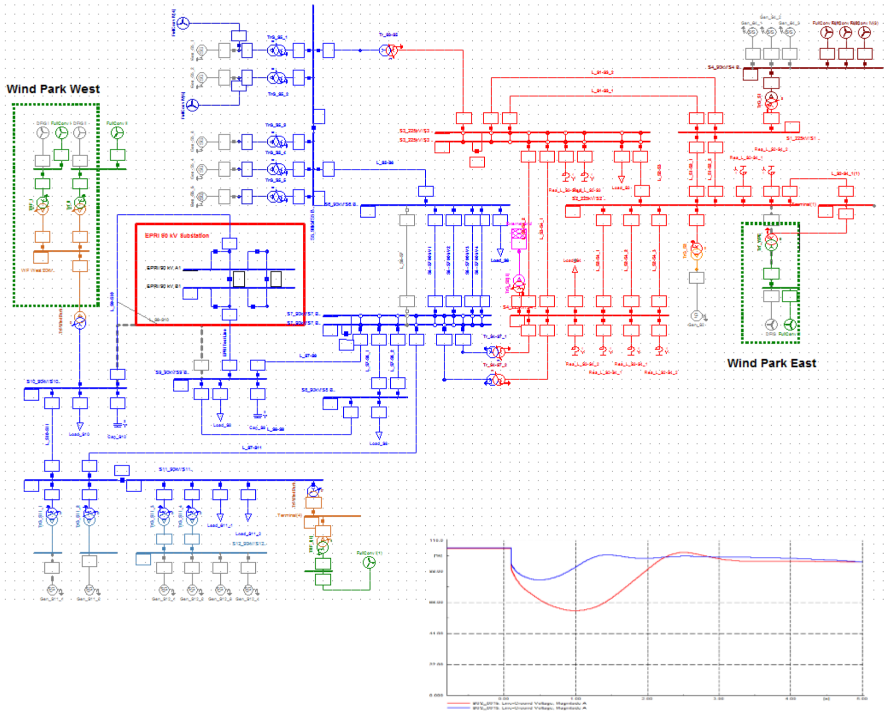
Existing Practices and Potential Future Solutions To Anti-Islanding Protection

Research Objective

- Resolve the modeling challenges, especially around performance of loads and protection when DER is islanded with the ultimate aim of developing and testing better islanding protection schemes

Plan for 2018

- Implement active anti-islanding control models
- Investigate performance of inverter active anti-islanding controllers using the grid models developed in 2017
- Review islanding protection solutions, systems and technologies
- Review existing protection methods against unintentional islanding, such as
  - Automatic grounding (shorting switch)
  - Configuring DER controls to ensure island is unstable (e.g. use Power Factor or var-control to collapse island)
  - More cost effective transfer trip (low frequency PLC etc)
  - Synchrophasor broadcast
- Assess new 1547 inverter impacts



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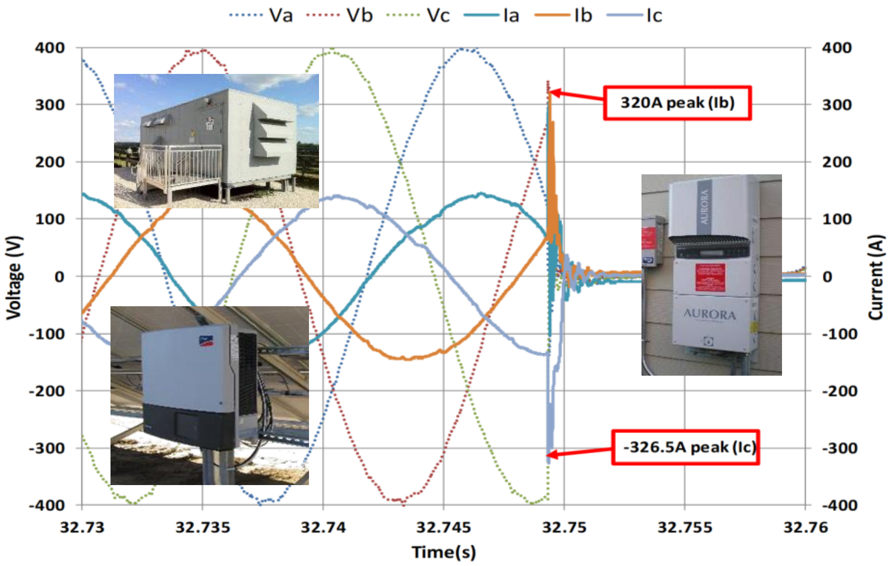
Inverter Fault Response for Protection and Planning

Objectives and Scope

- Improve methods to incorporate DER into planning processes and tools
- Measure device behaviors for a wide range of inverter DER types and scales - single/three-phase; PV/energy storage/hybrid; residential, C&I, and utility scale
- Develop, improve and verify models based on measured data

Value

- Improve system protection design, fault recovery and PQ analysis, and DER integration planning assessment.
- Have a ready knowledge base of commercial DER inverters' dynamic behavior :
  - Short-circuit current magnitude and duration
  - Active/reactive current during fault ride through and TOV
  - Inverter response time to grid fault
  - Grid synchronization during fault ride through
  - Grid reconnection time and behavior after fault
  - Response to distorted grid voltage



Details and Contact

- Project beginning July 2018
- Cost: TBD; Qualifies for TC and SDF

Aminul Huque, Sean McGuiness, Anish Gaikwad

- mhuque@epri.com, (865) 218-8051
- smcguiness@epri.com, (704) 595-2981
- AGaikwad@epri.com, (865) 218-8066

SPN Number: TBD

Improved Distribution and Transmission Planning with full Characterization of Inverters Representing Diverse Commercial Products

ELECTRIC POWER RESEARCH INSTITUTE

EPRI Grid Protection Task Force/Interest Group Meeting

When: July 16-18th,

Where: EPRI Charlotte Office, North Carolina

Who's Invited: Any and all Utility Protection Engineers

High-Level Agenda

Monday:

- Distribution Protection

Tuesday:

- Protection of Variable Generation
- Transmission Protection

Wednesday:

- Transmission Protection and Control

Early Draft Distribution Protection Agenda

- Roundtable of introductions and pressing issues
- Protection Settings – reclosers, outage planning, fuse-saving, and faster tripping
- Disturbances, fault location, restoration.
- Automated Protection Simulations & Analysis
- Member question and discussion session
- Islanding Protection - Practical Solutions and Technologies
- Leveraging Capabilities of Modern Protection
- Network Integration and Future Protection Issues
- Impacts on Protection - Managing Retirements

Planning for DER

Guidance on DER portfolios as non-wires solutions

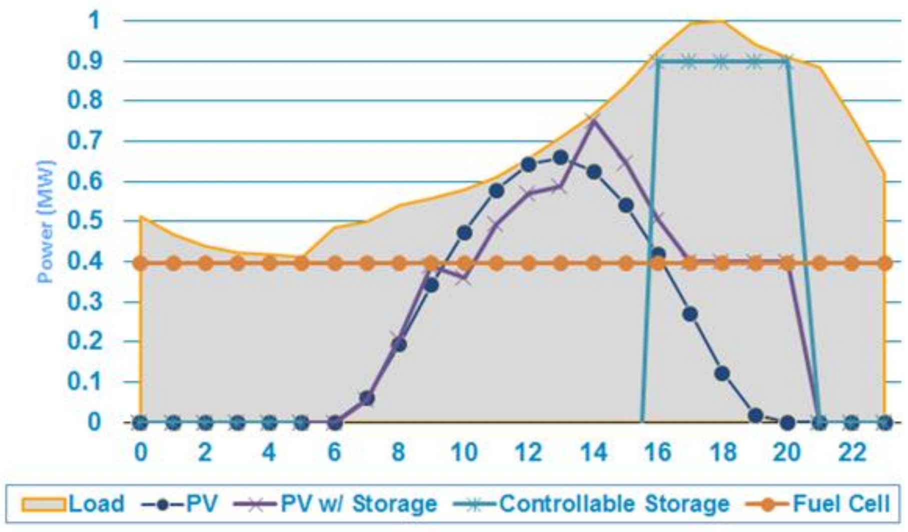
Distribution planner role of the future

Evolution of the planning process

Guidance on DER Portfolios as Non-Wires Solutions

Utility Need

DER may provide system benefits as non-wires solutions (NWS). However, they also introduce new dynamics that require additional models and assessments.



Research Objective

Develop guidance and methods to support the holistic design and evaluation of DER based NWS

Value

- Provide guidance on how DER portfolio limits could be determined for different DER types
- Explain how DER portfolios offer unique characteristics compared to traditional alternatives
- Guidance on the evaluation of DER as a NWS

Plan for 2018

- Identify and document current NWS planning practices
- Identify and classify relevant DER dynamic characteristics
- Derive guidance for defining portfolio performance requirements
- Develop methods for the holistic evaluation of NWS

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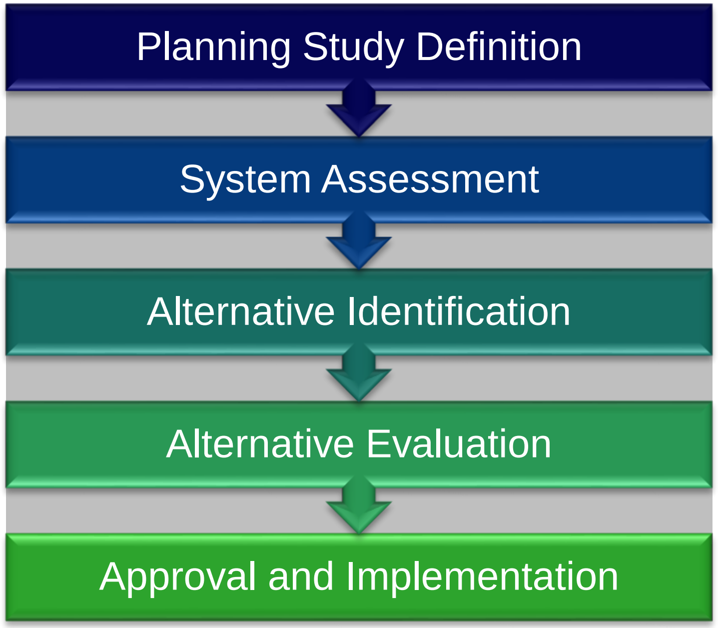
Future Planning Process



Utility Need

Distribution planning process and practices are evolving to meet future planning needs and objectives. As changes are rapidly occurring in discrete parts of the industry, increased understanding of the nature of these changes and ramification to the industry is needed.

Research Objective

Define new and effective planning process and practices to meet the evolving industry needs.

Value

- Inform distribution planning community on current activities
- Improve awareness of current and future challenges
- Provide a uniform industry voice

Plan for 2018

- Summarize recent activities influencing future distribution planning
- Identify current and ongoing planning changes
- Assess key drivers, considerations, and future challenges

Defining the Roles and Capabilities for the Planner of the Future

Utility Need

Technology advancements are changing distribution system designs as well as the methods used to plan the system. These changes may necessitate the need for expanded skill sets and increased knowledge of other technical areas.

Research Objective

Identify knowledge, skills, and abilities that future distribution planning personnel may need to support future planning efforts.

Value

- Increased understanding of future staffing needs
- Identification of key areas for training and education

Plan for 2018

- Member interviews
- Review of relevant engineering and education literature
- Assess future planner competencies (knowledge, skills, abilities, etc.)
- Identify considerations concerning future technical workface availability, retention and training

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NRECA articles and EPRI white papers on 1547

NRECA *Revision of IEEE Standard 1547™* Articles	Availability
1. The Background for Change, November 2016	NRECA + EPRI
2. Reactive Power and Voltage Regulation Capability Requirements, December 2016.	NRECA + EPRI
3. Disturbance Response Requirements, February 2017.	NRECA + EPRI
4. New Power Quality and Islanding Issues, April 2017.	NRECA + EPRI

EPRI white papers	Availability
5. Anti-islanding vs. ride-through	Draft underway
6. Communications interface and interoperability	Published
7. Power quality	Published
0. EPRI 1547 Fact Sheet	Published

EPRI Fact Sheet *available on epri.com*

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Additional Dates of Interest

- March 6-8, IEEE **1547.1** in Richmond, VA, hosted by Dominion
- April 23, EPRI webcast on substation unintended islanding and 3Vo protection, 174/200
- May 2-3, IEEE **1547** and DERMS tutorials and technical sessions at EPRI/Sandia PV System Symposium in Albuquerque, NM
- May 29, EPRI webcast for Inverter on-board anti islanding protection assessment project, 174/200
- June 11-13, IEEE **1547.1** in Boston, MA, hosted by National Grid
- July 16-17, EPRI Distribution Protection Task Force meeting, Charlotte, NC

Together…Shaping the Future of Electricity

ENABLING SMART INVERTERS FOR DISTRIBUTION GRID SERVICES

October 2018

ASSOCIATION 18 EDISON 85 ILLUMINATING CO'S

SDGE A Sempra Energy utility®

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Notice

This understanding of what will be required to enable Smart Inverter technology to become a reliable grid resource was made possible by the technical research to-date undertaken by California utilities, AEIC member utilities and utilities across the U.S. This research has been supported by collaboration and engagement with industry stakeholders such as Distributed Energy Resource (DER) vendors/aggregators, equipment manufacturers, and research institutions such as the Electric Power Research Institute (EPRI) and the National Renewable Energy Laboratories (NREL). Through execution of Smart Inverter demonstration projects in our respective service territories, the Investor Owned Utilities (IOUs) and other utilities have learned about the potential of Smart Inverters and also the remaining barriers to fully realizing their value. In particular, much of the research was enabled by California's Electric Program Investment Charge (EPIC) in its two past cycles (EPIC 1, 2012-15 and EPIC 2, 2015-18). With continuing commitment by regulators to fund this important research, development and demonstration (RD&D) work in the current EPIC cycle (EPIC 3 2018-2020), the IOUs can continue to develop capabilities, define system requirements, and generate technical, process, and human capital learnings related to how Smart Inverter technology can provide benefits to California.

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List of Acronyms

ADMS	advanced distribution management system(s)
AMI	advanced metering infrastructure
BESS	battery energy storage system(s)
BTM	behind-the-meter
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DER	distributed energy resource
DERMS	distributed energy resource management system(s)
DMS	distribution management system
EPIC	Electric Program Investment Charge
EV	electric vehicle(s)
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor owned utility
kW	kilowatts
kVAr	kilovolt amperes reactive
MUA	multiple use applications
PV	photovoltaic(s)
SCADA	supervisory control and data acquisition
SI	smart inverter
SIWG	smart inverter working group
TOU	time of use

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Executive Summary

The presence of Distributed Energy Resources (DERs) on the electric grid has been increasing in recent years, especially in California, and this trend is expected to continue[1]. DERs such as electric vehicles (EV), solar photovoltaics (PV), and battery energy storage systems (BESS) represent an important part of the resource portfolio needed to address California's clean energy goals and expand consumer choices. At the same time, DER integration into the distribution grid presents both challenges and opportunities for grid planning and operations. Recent utility experience demonstrates that Smart Inverters have the potential to enable DERs to support grid needs when combined with new capabilities that enable full integration of DERs into the utility's grid planning and operations. This experience has identified multiple factors for allowing Smart Inverter-enabled DERs to minimize potential grid impacts at higher DER penetration levels and, when cost competitive, to provide distribution grid benefits such as deferral of utility investments, increased capacity, improved power quality, enhanced reliability, and greater resiliency.

This white paper is a joint collaborative effort of Pacific Gas & Electric (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE), collectively the California IOUs, and member utilities in the Association of Edison Illuminating Companies (AEIC) DER Sub-Committee. It is intended to inform electric utilities, regulators and DER industry stakeholders nationwide by addressing the following questions through results and learnings achieved in demonstration projects:

- What considerations need to be addressed for Smart Inverter-enabled DERs to become an effective technology to maintain and/or enhance distribution grid safety, reliability and customer affordability?
- What are the key learnings that the IOUs have gained on Smart Inverters through demonstration projects?
- What questions remain to be answered?

Recent California utilities' experience has highlighted the following six (6) key considerations for Smart Inverter-enabled DERs to become an effective and reliable distribution grid resource:

1. Location and volume of Smart Inverter-enabled DERs on the distribution grid is important

- For most distribution grid services, the distribution system will require location-specific services to address specific system constraints or needs[2]. Significant distribution service needs that require investment do not exist everywhere.

[1] SEIA Solar Market Insight Report 2018 Q2: https://bit.ly/2JyMH9f

[2] Integrated Distribution Planning, Paul De Martini, ICF, for Minnesota PUC: https://bit.ly/2N4Zihn

- The effectiveness of Smart Inverter-enabled DERs to support locational grid services is highly dependent on DER penetration levels and feeder characteristics.

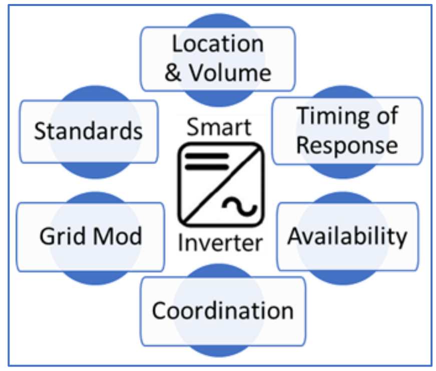


Figure 1: Six factors for Smart Inverter-enabled DER grid value

2. **Timing of Smart Inverter-enabled DER response should align with distribution grid need**
   - The distribution system has dynamic needs that can occur at various times within a day, month, or season
   - Currently, output of most customer-sited Smart Inverter-enabled DERs (e.g. PV, batteries, or EVs) is not coordinated with dynamic grid conditions.

3. **Availability and assurance of Smart Inverter-enabled DERs to provide grid response is needed for critical distribution services that support grid safety and reliability**
   - For Smart Inverter-enabled DERs to successfully provide critical distribution services such as voltage support, capacity and reliability, they should provide distribution services with a comparable level of performance as traditional utility "wires" infrastructure.
   - IOU demonstration experience suggests communications to DER assets requires additional research, development and demonstration.

4. **Coordination between the utility and DERs or DER aggregators is important**
   - Smart Inverter-enabled DERs and their data must be visible and available to the utility and/or aggregator for these resources to be fully utilized by the Distribution Operator.
   - Standardization of communication and operational procedures is necessary between utilities and DER providers to ensure instructions are received, interpreted and executed consistently by different aggregators.

5. **Capabilities provided by grid modernization technology deployments will enable Smart Inverter-enabled DERs to provide distribution grid services beyond autonomous Smart Inverter functions**
   - Utility operational capabilities and systems that automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and DER assets are needed to enhance the value of DERs to the grid.
   - The management systems and communication infrastructure used to integrate DERs are as critical as the DERs themselves and must have reliability and redundancy comparable to traditional utility "wires" infrastructure.

6. **Unified standards, comprehensive testing and certification, and training for DER installers are needed to ensure safe, reliable and resilient Smart Inverter operation, communication and cybersecurity**
   - Phased implementation of standards for advanced Smart Inverter functions has created complexity for manufacturers in getting Rule 21-compliant Smart Inverters to market

and for Nationally Recognized Testing Laboratories (NRTLs) to certify and test Smart Inverters.

- Improved manufacturer product documentation and standardization of Smart Inverter feature names and user interfaces is needed to facilitate proper configuration during field installation.
- Cybersecurity standards need to be adopted by the industry and integrated into relevant communication standards for Smart Inverter interconnection. Existing methods to ensure end-to-end cybersecurity between the utility and Smart Inverter-enabled DERs need significant improvement.

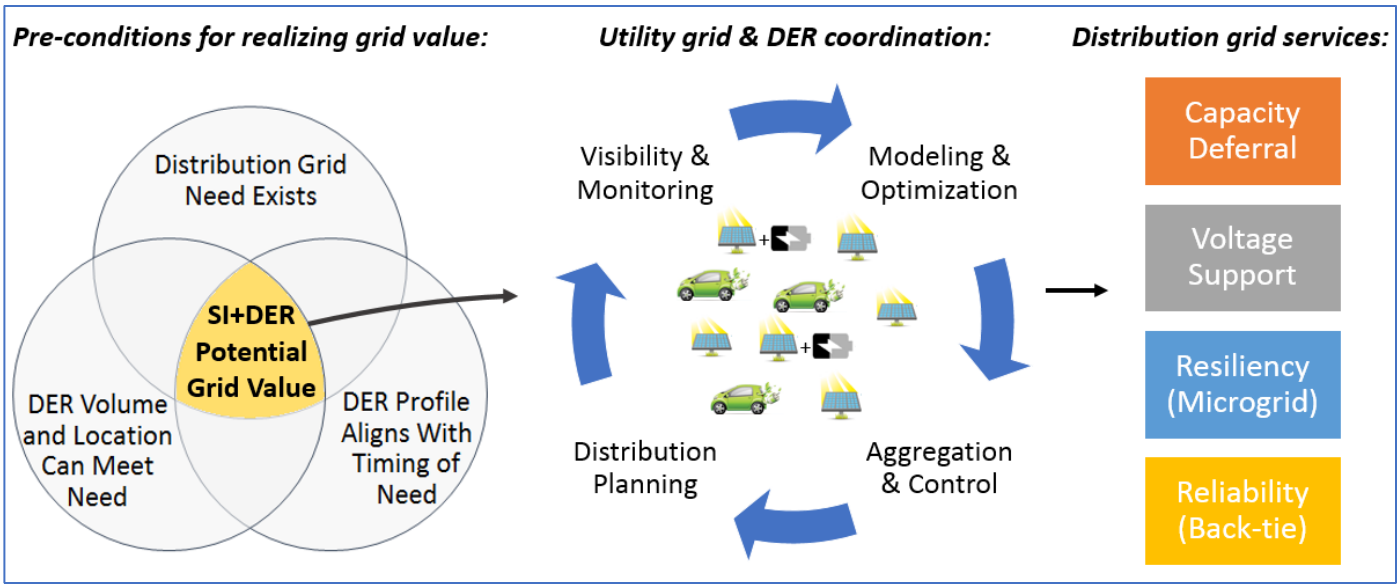


Figure 2: Components of Smart Inverter-enabled DER coordination for distribution grid services

To fully realize the value of Smart Inverter-enabled DERs, utilities need to continually improve methodologies to identify locations where grid needs exist and to assess capabilities and cost-competitiveness of DERs to meet those needs. Standards and utility investments that support interoperability between aggregators and utilities can allow Smart Inverter-enabled DERs to be "good citizens" of the distribution grid at high penetrations and evolve the electric system to be more reliable, resilient, and affordable.

1. Background on Smart Inverters and DERs

The presence of Distributed Energy Resources (DERs) on the electric grid has been increasing in recent years, and DERs are expected to continue to be rapidly interconnected onto the distribution grid[3]. While this trend has been experienced nationwide, it is particularly pronounced in sunny states like California, Arizona and Hawaii where policy, regulation and progressive consumer preferences have, in combination with evolution in DER technology and a subsequent reduction in costs, driven accelerated adoption of DERs[4]. In February 2015, the California Public Utilities Commission (CPUC) issued the Distribution Resources Plan (DRP) Rulemaking R.14-08-013[5], which foresaw incorporation of DERs into day-to-day grid operations and long-term distribution grid planning and investment decisions.

Distributed solar PV and other DERs such as battery storage systems and EVs represent an important part of California's clean energy portfolio and an avenue for customer choice[6]. However, incorporation of DERs onto the distribution grid raises challenges for the electric system, where the primary goals will continue to be delivering safe, reliable and affordable electricity for its customers. Technical grid challenges related to high DER penetration in certain instances include thermal violations, protection system impacts related to bidirectional power flow, and power quality issues[7].

1.1. What is a Smart Inverter?

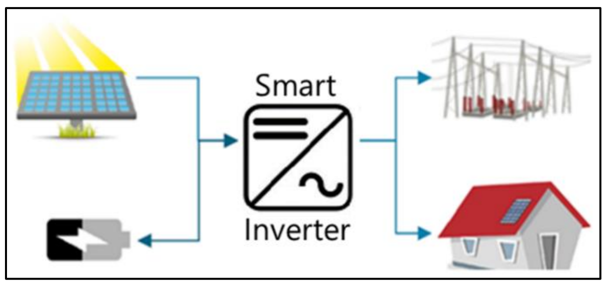


Figure 3: Smart Inverters convert DER output for use in homes and the grid

The basic function of a standard inverter is to convert the direct current (DC) output of an energy source such as a PV system to alternating current (AC) that can be fed into the electric grid or used onsite. California's Rule 21[8], the tariff under which Smart Inverter (SI)-enabled DERs can interconnect to the California IOUs distribution grids, defines a SI as an "inverter that performs functions that, when activated, can autonomously contribute to grid support during excursions from normal operating voltage and frequency system conditions by providing: dynamic reactive/real power support, voltage and frequency ride-through, ramp rate

[3] See Appendix A, "PV Growth in California"

[4] These include CA Senate Bills 350, X1-2, and 100, and energy metering (NEM) policies and federal tax subsidies incentivizing residential and commercial PV adoption (Solar Investment Tax Credit: https://bit.ly/2zDmwYE)

[5] Distribution Resources Plan (R.14-08-013) https://bit.ly/2pRY540

[6] EPRI Integrated Grid report: https://bit.ly/2RJuq9O

[7] Emerging Issues and Challenges in Integrating Solar with the Distribution System: https://bit.ly/2xNqfBt

[8] PG&E Rule 21 interconnection tariff: https://bit.ly/2pRY540

controls, communication systems with ability to accept external commands and other functions."

DER interconnection rules requiring SIs, such as California's Rule 21, can help the grid to host more DERs, can minimize the negative impact of DERs on grid power quality and can potentially lower interconnection costs. IOU experience has shown that when a customer installs solar PV, the PV system offsets their load and sends power to the grid, which may increase voltage levels and variability on the secondary (e.g. low voltage system) of the service transformer[9]. The exact increase is dependent on the amount of DER capacity installed relative to load as well as electrical conditions in the distribution line. This local increase of voltage can not only affect that DER customer's voltage but also raise voltage for neighboring customers served by the same electric service system. Consequently, at high penetrations, DERs can elevate voltage levels on the secondary and primary (medium voltage) systems.

In addition to elevated voltages, high penetrations of DERs can cause thermal problems due to high reverse power flows, can interfere with the operation of protection systems, and can result in issues such as electrical load masking. All of these challenges lead to increased complexity of day-to-day distribution grid operations and can impact electric service reliability and safety.

To address some of these concerns, the electric utilities nationwide have been actively supporting the evolution of SIs. Updated interconnection standards incorporating autonomous SI functions such as Volt-VAr and Volt-Watt are a first step to ensuring that customer-sited DERs do not cause adverse impacts to grid safety, reliability, and power quality. These SI functions can also help delay or avoid some distribution upgrade costs that may otherwise be passed on to the interconnecting customer or rate-based, and lay a foundation for DERs to potentially provide distribution grid services.

1.2. Smart Inverter Functions and Capabilities

Beyond autonomous functions, SIs can also enable active or real-time control of DERs through a Distributed Energy Resource Management System (DERMS) and an Advanced Distribution Management System (ADMS). This distinction between autonomous and active control is illustrated below:

Table 1: Autonomous vs. active control use cases for SI-enabled DERs

Smart Inverter Operating Mode		Use Cases
Autonomous	Pre-programmed parameters that run independent of any additional external control signals, and that may be locally or remotely changed infrequently.	• Help customers avoid paying for distribution upgrades for DER interconnection (for example, upgrading a dedicated customer transformer) • "Ride through" momentary disturbances to frequency or voltage

[9] SDG&E SI Demonstration C Project: In the specific configuration tested in Demo C, SDG&E found that 120 kW of solar PV resulted in a 6 volt increase in voltage at 12pm over the no PV scenario: https://bit.ly/2InkePW

Smart Inverter Operating Mode		Use Cases
	Analogous to a grid voltage regulator or capacitor, which is programmed to automatically respond to a range of grid voltage conditions.	• Inject or absorb reactive power into or from the grid (Volt-VAr) to support voltage within mandated levels • Limit real power output when voltage is high (Volt-Watt) • Provide a "soft start" after power outages • Increase DER hosting capacity[10]
Active Control	The ability to receive and execute remote commands to address dynamic grid conditions using a DERMS/ADMS platform. Analogous to today's grid operator using a DMS to remotely operate a SCADA device such as a sectionalizer to re-balance load across adjacent circuits.	In addition to autonomous capabilities, potential to provide: • Additional capacity (peak load shaving) – example: SI-enabled battery storage dispatched to relieve substation congestion during peak loading hours • Enhanced reliability and resilience – example: PV + storage designed for microgrid operation used to more quickly restore customers following an outage

California's Smart Inverter Working Group (SIWG) has been instrumental in defining the above capabilities including current and upcoming California Rule 21 requirements for SIs. For additional background on the SIWG's activities, Phases 1, 2 and 3 SI functions and evolution of the IEEE 1547 interconnection standard, see Appendices C and E.

1.3. What are Distribution Grid Services?

Electric utilities' distribution planning process evaluates and specifies projects to ensure availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system[11]. This process is focused on identifying and implementing "least cost-best fit" solutions to provide four key grid services: 1) Distribution Capacity, 2) Voltage Support, 3) Reliability (Back-Tie) and 4) Resiliency. Distribution Grid Services can be provided by a host of solutions, ranging from traditional hardware (generators, transformers, voltage regulators, capacitors) to newer technologies such as a portfolio of SI-enabled DERs. These DERs could operate in an autonomous or actively-controlled manner, depending on the use case and type of service needed. An overview of the four distribution grid services in the DER context is provided below in Table 2:

Table 2: Potential distribution grid services provided by SI-enabled DERs

Distribution Capacity	Load-modifying or supply services that DERs could provide via the dispatch of generators or reduction in load that can reliably and consistently reduce net loading on desired distribution infrastructure. These capacity services could be provided by **autonomous DERs** or more likely **actively-controlled DERs** that meet an identified operational need in response to a control signal from the utility.

[10] For more detail, see Appendix B, SIs and Hosting Capacity

[11] For a more detailed description of this process, see Appendix F, Distribution Grid Planning Process

Voltage Support and/or Reactive Power Support	Voltage management services that could be provided by **autonomously or actively-controlled DERs** capable of dynamically correcting excursions outside of voltage limits. A Smart Inverter can support this capability by absorbing or injecting reactive power (Volt-VAr) as well as by controlling real power output (Volt-Watt) to maintain local voltage within Rule 2 limits[12]. Only the ability to support voltage beyond simply mitigating voltage rise caused by the DER itself would be considered a distribution grid service.
Reliability (Back-Tie)	Load-modifying or supply services capable of reducing the frequency and duration of outages. Specifically, the back-tie reliability service provides a fast reconnection from one feeder with an identified operational need to one or more backup feeders that have excess capacity reserves (including those provided by DERs) to restore customers during an outage. This service could be provided by **autonomously** or **actively-controlled DERs**.
Resiliency (Microgrid)	Load-modifying or supply services capable of improving the local distribution system's ability to quickly recover from an outage. This service provides power to intentionally-islanded end-use customers through an ad-hoc microgrid when central power is not supplied, reducing the duration of outages. These resiliency services could be provided by **actively-controlled DERs** meeting an identified operational need in response to a control signal[13]. See section 2.5, *Grid Modernization* for utility investments that would be needed to enable this service.

For SI-enabled DERs to successfully provide distribution services, they must meet similar technical and operating standards as the rest of the distribution system such that when DERs are interconnected and operated in grid support modes, they can maintain the safety and reliability of the distribution grid.

2. Key Considerations and Insights Achieved in Smart Inverter Pilots

2.1. Smart Inverter Demonstrations Undertaken by Distribution Utilities

Recent demonstration projects at the California IOUs and other U.S. utilities have shown that SI-enabled DERs have the potential to respond to certain grid needs. By partnering with DER vendors/aggregators and SI manufacturers, the IOUs have demonstrated that SI-enabled DERs can help with local secondary voltage regulation and provide distribution capacity services, and that remote change of autonomous SI settings using an aggregation platform is possible. Some of the IOU SI findings are also supported by the Arizona Public Service (APS) Solar Partner Program, which performed the largest and most comprehensive SI field deployment to date[14]. However, the IOU demonstrations have revealed challenges that must be overcome for SI-enabled DERs to consistently provide distribution grid services. These challenges include: difficult targeted customer acquisition, unreliable communication to SIs, and inconsistent

[12] CPUC Rule 2 describes electric service requirements, which includes the acceptable secondary voltage ranges of electric service to electric customers.

[13] In a microgrid application it is necessary for a system to match generation to load while maintaining voltage, frequency, and power quality within appropriate limits.

[14] Arizona Public Service Solar Partner Program: Advanced Inverter Demonstration Results: https://bit.ly/2yoKd59

application of SI commands via aggregation platforms. Figure 4 below summarizes the California IOU demonstrations and key findings[15,16]:

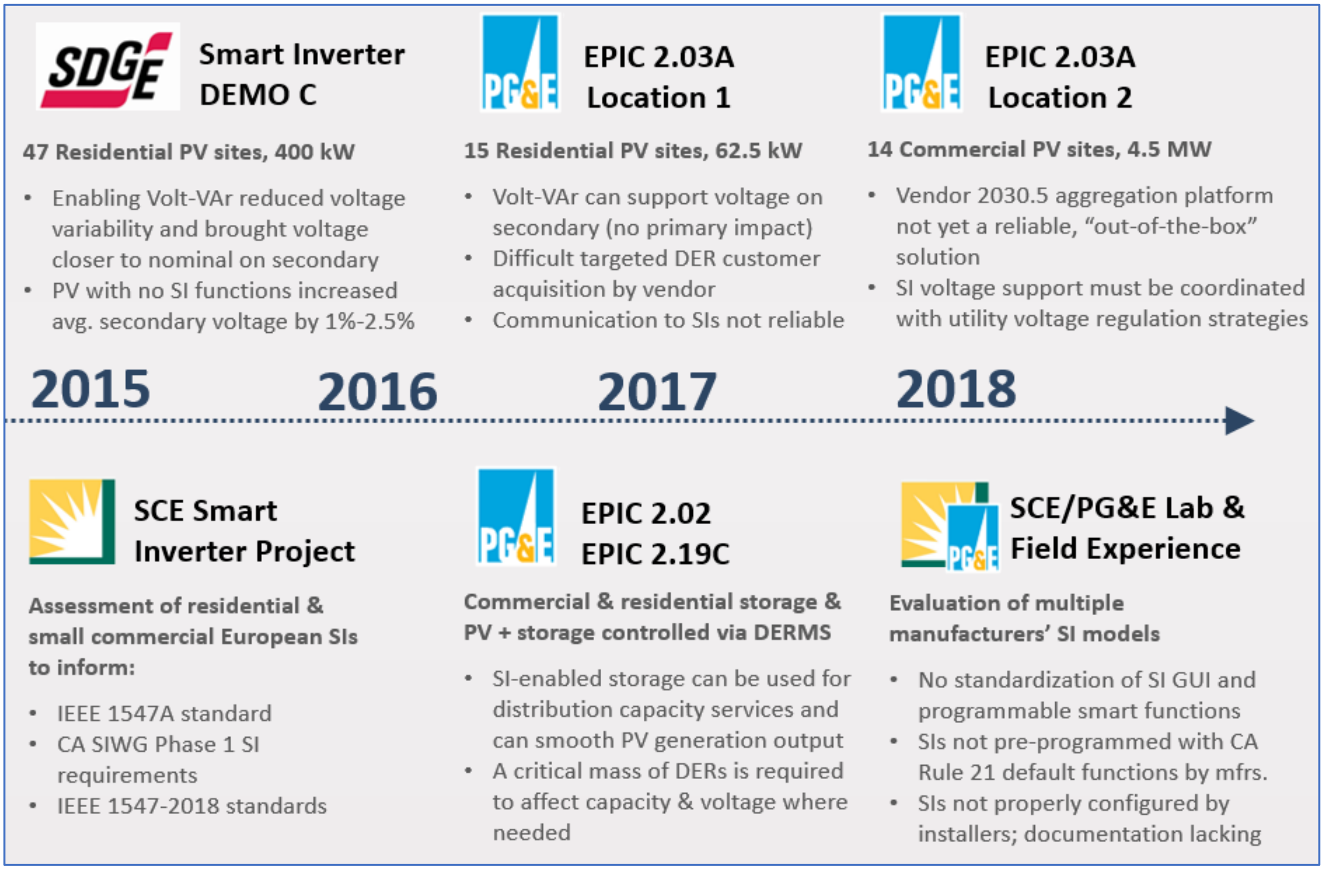


Figure 4: Key Learnings from Smart Inverter Demonstrations Undertaken by California IOUs

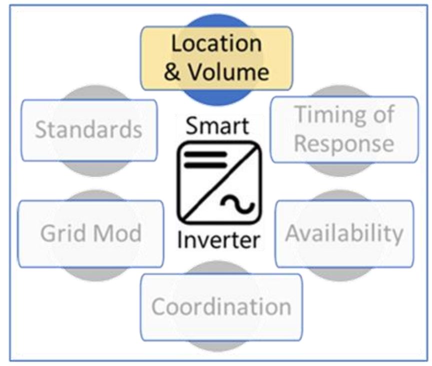
SI demonstrations have also been completed by utilities outside of California and Arizona, such as by the Hawaiian Electric Companies (HECO), Duke, and National Grid, references to which are available in Appendix G. Outside of the U.S., European experience also supports the need for advanced inverter functions. In 2013, Germany was forced to retrofit 300,000 BTM PV inverters with updated frequency ride-through settings, at significant cost to German electric ratepayers[17]. The adoption of communications capability that allows for remote change of autonomous SI settings will prevent such scenarios from occurring in the future.

[15] SDG&E Smart Inverter Demo C Report: https://bit.ly/2OcQNGp; PG&E EPIC 2.03A Interim Report/EPIC 2.19C Final Report: https://bit.ly/2NyvgDp, https://bit.ly/2P7BE5q; PG&E EPIC 2.03A Smart Inverter Final Report (Location 2) and EPIC 2.02 Report: Available Q1 2019; SCE Smart Inverter Project Reports: https://bit.ly/2RziE1A, https://bit.ly/2OgNlLj, https://bit.ly/2IJoyJJ

[16] For more detail on each of the projects summarized in Figure 5, see Appendix D

[17] IEEE: The Impact of Distributed Solar on Germany's Energy Transitions: https://bit.ly/2EcJsSD

2.1. Location and Volume of Smart Inverter-enabled DERs on the Distribution Grid is Important



Significant grid infrastructure needs that require investment do not exist everywhere. Where needs do exist, the distribution system will require location-specific services to address them[18]. For example, the need to replace an undersized substation transformer that could overload may be met with DERs interconnected on the distribution feeder downstream of that transformer. A deficiency on a certain section of a distribution feeder would require that DERs interconnected to the overloaded section operate to ensure that the overload issue is mitigated[19].

California' Rule 21 tariff began requiring SIs with Phase 1 SIWG functions on new inverter-based DER installations in California IOU territories in September 2017. Since these changes to Rule 21 are still relatively new, SI-enabled DER penetration is still low relative to peak load on most California distribution circuits, as illustrated below in Figure 5[20].

With organic growth over the next several years, SI-enabled DERs may begin to reach penetration levels where they can be considered as a solution for distribution grid services in some locations. In the meantime, the CA IOUs encourage the replacement of standard inverters with SIs for existing DERs to reach these penetration levels more quickly.

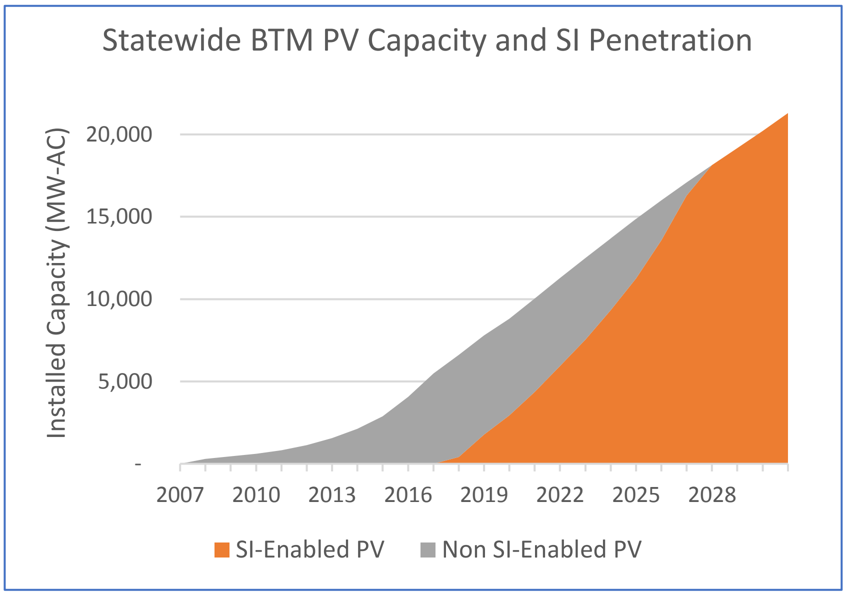


Figure 5: Statewide BTM PV Capacity and Smart Inverter Penetration

In the SI field demonstrations completed to-date by the California IOUs and other utilities[21], it was observed that at low penetration levels it may be difficult to see aggregate

[18] Integrated Distribution Planning, Paul De Martini, ICF, for Minnesota PUC: https://bit.ly/2N4Zihn

[19] The Distribution Resources Plan (DRP) proceeding is developing a Locational Net Benefit Analysis (LNBA) framework to identify locations for DERs to benefit the distribution grid: https://drpwg.org/sample-page/drp/

[20] Data source: CEC historical data for CA installations from 2007-2017; CEC mid-mid forecast for 2018-2030

[21] See appendices D and H for a full list of utility SI demonstration projects completed to date

effects of SIs for improving power quality or increasing hosting capacity[22]. Simulations, such as in HECO's Voltage Regulation Operational Strategies (VROS) project[23] and the Duke Energy Case study[24], have shown the benefits of SIs at higher penetration levels and minimal curtailment due to Volt-Watt curves, but this has yet to be demonstrated on a residential feeder in the field.

Field demonstrations by SDG&E and PG&E evaluated the aggregate effects of 400 kW and 62.5 kW of SI-enabled BTM PV, which comprised approximately 6% and <1% of the test feeders' peak demand, respectively. Due to these low penetrations, aggregate SI functions were observed to have little to no measurable impact on the distribution grid. Specifically, there was no measurable effect on the primary (e.g. medium voltage) system and there were small effects on the secondary service (e.g. low voltage) system. It is also important to note that the electric distribution feeders (e.g. lines) that were used for this demonstration were robust or less prone to voltage disturbances based on their design, making them less likely to be influenced by SI reactive power support[25].

As observed by the IOUs and in the additional utility SI demonstrations cited above**,** the effectiveness of SIs depends on DER penetration levels and distribution system design characteristics at a given location[26] as well as customer load and customer generation operating profiles. Given that SI impacts are highly dependent on penetration and location, the ability of SI-enabled DER aggregations to provide grid services reliably and where needed is currently limited by existing penetration levels, but this capability is expected to grow as SI-enabled DERs proliferate.

2.1.1. Targeted Customer Acquisition Challenges

A related challenge to SI penetration and location is the ability to deploy new SI-enabled DERs or retrofit existing DERs with SIs in a targeted fashion, which may be necessary as localized grid needs are identified. In its EPIC 2.03A SI project, PG&E relied on vendors to acquire new residential customers to participate in the demonstration. Vendors encountered significant challenges in meeting customer acquisition objectives, leading to penetration targets ultimately not being met. The challenges may have been related to limited access to customer information, customer fatigue from door-to-door solar outreach, and existing DERs being ineligible for SI retrofit due to residential solar system ownership structure and restrictions on curtailment. These customer acquisition challenges were not unique to PG&E. SCE, in its

[22]In SDG&E's DRP Demo C/PG&E's EPIC 2.03A projects, the limited amount of Smart Inverter-enabled PV was only able to impact secondary voltages and not the primary distribution where voltage regulation schemes are in place.

[23] Simulation of HECO Feeder Operations with Advanced Inverters: https://bit.ly/2NwauUD

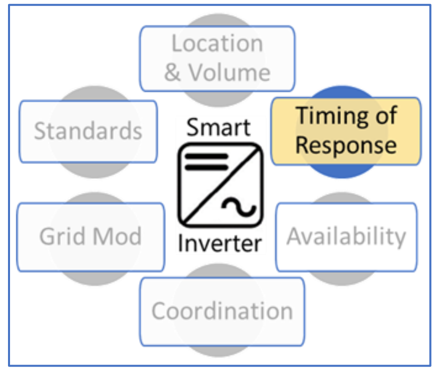
[24] Feeder Voltage Regulation with High-Penetration PV Using Advanced Inverters: https://bit.ly/2IK186M

[25] PG&E is currently evaluating a feeder where SI-enabled PV represent a greater percentage of that feeder's peak load (35% penetration of DERs participating in the demo vs. peak load) and voltage excursions above 105%.

[26] For example, the ratio of system reactance to system resistance (X/R) at a given point, and the location and number of capacitors and voltage regulators. Reactive power support is most effective where X >> R.

Integrated Grid Project EPIC 1 results[27], also encountered difficulty regarding customer participation in a program to monitor Smart Inverter-enabled DER data. More work is needed in this area to develop potential solutions to overcome these challenges.

2.2. Timing of Smart Inverter Response Should Align with Distribution Grid Need



The distribution system has dynamic needs that can occur at various times within a day, month, or season and may change over time. For example, the electric demand loading profile of one distribution feeder may reveal that high loading occurs for a few hours in the evening during the summer months, while another feeder may exhibit high loading in the early afternoon. Similarly, one feeder may experience low voltage in the morning while another has low voltage in the evening. These variations can be attributed to differences in customer types, geography, weather, and other factors.

Currently, the output and/or charging behavior of most customer-sited SI-enabled DERs (e.g. PV, batteries, or electric vehicles (EVs)) is not coordinated with or optimized for these constantly-changing grid conditions. For example, PV supplies peak power onto the grid at mid-day, which may be a time of low loading for many evening-peaking residential feeders. Consequently, an evening capacity constraint on such a feeder would not be lessened by the presence of distributed PV; in this example, the grid need, and DER profile are effectively mismatched as shown in Figure 6.

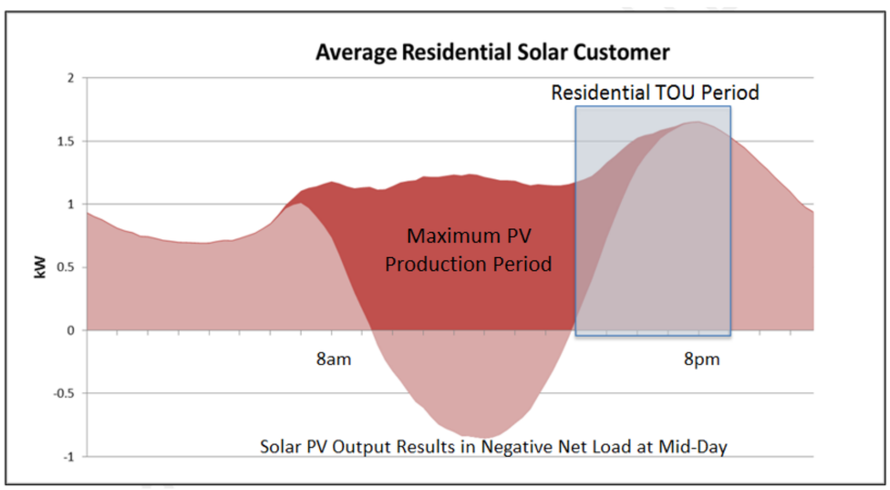


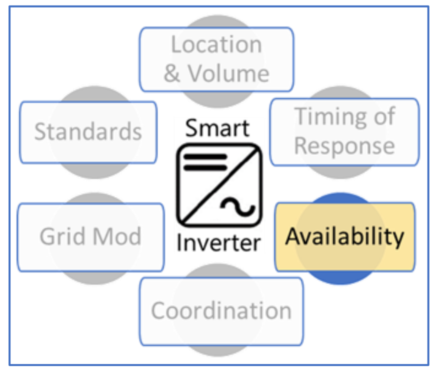
Figure 6: Net load of average residential SDG&E solar customer

By and large, today's customer-owned DER operating profiles are optimized for consumer needs as opposed to local distribution grid conditions and needs; BTM PV production is maximized to offset customer bills and BTM storage is typically charged/discharged for time-of-use (TOU) rate arbitrage or peak demand

[27] SCE Integrated Grid Project EPIC 1 Presentation: https://on.sce.com/2R6Wu6C

shaving[28]. As Smart Inverter capabilities mature beyond autonomous functions, the ability to control DERs in coordination with a DER-aware distribution operations system such as a DERMS and ADMS will improve the potential to match DER capabilities more closely with dynamic grid needs[29]. These systems will consider the specific DER types, sizes, concentrations and locations relative to localized grid needs and will require foundational utility technology deployments to operationalize.

2.3. Availability and Assurance of Smart Inverter-enabled DERs to Provide Response is Needed for Critical Distribution Services that Support Grid Safety and Reliability



For SI-enabled DERs to successfully provide critical distribution services such as voltage support, capacity and reliability, they should meet performance requirements similar to the rest of the distribution system. DERs should be readily available to provide distribution services with a comparable level of certainty that a traditional "wires" upgrade provides today. For example, if an aggregation of SI-enabled PV + storage is used to defer a traditional "wires" upgrade for a capacity constraint on a feeder, it must perform reliably during all hours of the year that the capacity constraint exists and at other agreed-upon times. It must also be able to consistently address the worst-case distribution planning scenario (e.g. a prolonged heatwave resulting in record loading due to concurrent air conditioner usage). Scenarios such as a communications outage that prevents the DERs from receiving commands or relaying data to the utility or aggregator must be considered.

Based on experiences to-date in working with DER aggregators, the IOUs have identified areas for the utility and industry to tackle to enable greater DER value. In PG&E's EPIC 2.03A Location 2 demo, the IEEE 2030.5 SI aggregator solution routinely failed to recover from temporary satellite and cellular communications outages, requiring a manual reset to restore visibility and control of SI-enabled PV systems. Similarly, SDG&E's SI Demo C experience and PG&E's EPIC 2.19C/EPIC 2.03A Location 1 demos showed that the reliability of SI communications was well below the average communication reliability for Supervisory Control and Data Acquisition (SCADA)-enabled devices, such as line reclosers[30]. For distribution services, this creates challenges associated with performance since customer needs require a high degree of distribution system reliability.

In general, the reliability of a DER or DER aggregation should follow the criticality of the specific grid service that is provided. Certain use cases may not require a guarantee of near-100% uptime as, for example, a bulk generator, while others may be absolutely critical where the

[28] "Who Should Own and Operate DERS?" https://bit.ly/2NMFvIR

[29] EPRI "Understanding DERMS" White Paper: https://bit.ly/2OV0J3J

[30] PG&E's average communication reliability for SCADA-enabled devices, such as line reclosers is above 96%.

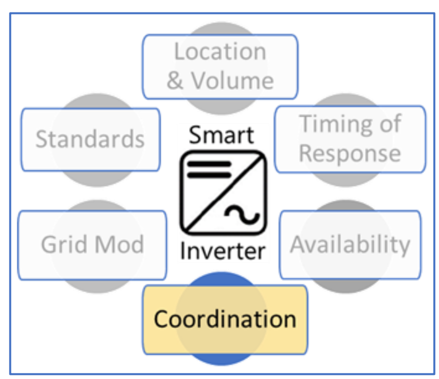
uptime of both the DER assets and their communication systems is equally important. In certain cases, rules, processes, or penalties may be needed to address situations where DERs fail to meet an obligation to provide grid services.

2.3.1. Reliable Measurement and Verification for DER Services is Needed

As opportunities for SI-enabled DERs to provide grid benefits beyond autonomous functions begin to be realized by utilities, customers and aggregators, a robust methodology for validating the DER's grid impact must be established. This capability will be needed for purposes of settlement to verify compliance with a contract, and will also allow grid operations and planning to more fully account for the impact of DERs on the distribution system. Components/principles that need to be further explored include:

1) The SI resource and its data must be visible to the utility and/or aggregator[31]. Currently, most utilities do not have adequate visibility into the impact of DERs on local voltage and capacity. Utility access to DER data should be included in DER interconnection agreements, since even small DERs can have significant grid impact at high aggregate penetrations.
2) The utility must have the systems in place to integrate DER data with its grid monitoring and control platform. Such a system must be capable of performing validation to verify that the SI provided a grid service (e.g. voltage support) beyond simply mitigating the adverse impact of high DER penetration.
3) For non SI-enabled DERs (e.g. legacy systems) where data monitoring is unavailable, utilities will need to develop new forecasting capabilities in order to account for the grid impacts of those DERs.
4) In active control use cases and some autonomous use cases, the DER must be able to be coordinated/controlled to provide the grid service, such as by a grid operator through an ADMS or DERMS.

2.4. Coordination Between the Utility and Aggregator is Important



As SI-enabled DERs play an increasingly important role on the distribution grid, coordination between utilities and aggregators will be critical to ensuring that grid needs and the ability of DERs to meet those needs are communicated in a timely and accurate manner. For example, for a fleet of BTM batteries to meet a temporary capacity constraint on a given circuit, the aggregator will need to reliably communicate the availability and state of charge of those batteries to the utility. The utility will need the capability to accurately model the amount of capacity required and translate that need into a dispatch signal to the aggregator or individual SI-enabled battery assets.

[31] Phase 2 SIWG function – DER to utility communications and Phase 3 function – monitor key DER data.

Alignment and standardization is also necessary between the utility and DER operators to ensure instructions are interpreted consistently by different aggregators, especially if multiple aggregator platforms take different approaches to SI management. Examples include how to handle multiple schedules and/or overlapping control modes, how to measure key operating metrics, and how to interpret instructions. While some of these scenarios are specifically addressed in standards, experience to-date has shown that different vendors may interpret the same command differently. In PG&E's EPIC 2.02 DERMS Project, when a DER was given a dispatch command beyond its capability, one vendor would dispatch as much as possible, while another vendor cancelled the command and did nothing. In SDG&E's Demo C pilot, the fixed power factor setting responses activated by the aggregator were the opposite of requested settings, e.g. producing VArs instead of absorbing VArs[32].

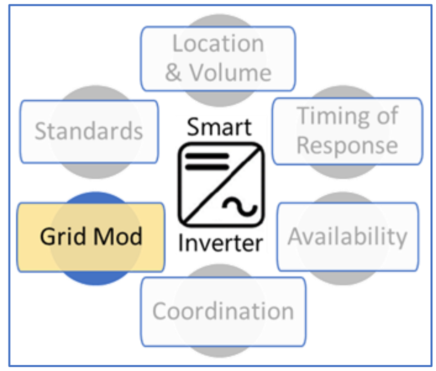
PG&E's EPIC 2.19C project, "*Customer Sited and Behind-the-Meter Storage*", demonstrated both technical potential of SI-enabled BTM energy storage to provide grid reliability support and highlighted next steps required to enable scalability. PG&E found that communication between the storage aggregators and individual SI-enabled storage assets was an ongoing challenge. In some cases, dispatch signals were not followed because a communications outage prevented the storage asset from receiving it. The ability of both participating aggregators to reliably drop load as instructed was compromised due to frequent loss of communications link with the storage assets.

In addition to accurate aggregator communication of DER states and availability, clear utility signals related to loading, voltage, and as-switched grid configurations are equally important. Specific coordination challenges are posed by the dynamic operating conditions of each distribution feeder, frequent rerouting of power to minimize the duration and magnitude of local outages (switching), and the need for work clearances (planned outages) to ensure the safety of the public and utility crews[33]. Operational capabilities and systems that can automatically analyze grid conditions, determine optimized solutions, and communicate signals to aggregators and DER assets are needed to enhance the value of DERs to the grid operator and planner.

[32] Since this demo, the Common Smart Inverter Operating Profile (CSIP) was established and would likely help prevent such issues.

[33] Coordination of T&D in a high DER Electric Grid: https://bit.ly/2qEf8Gw

2.5. Grid Modernization Initiatives are Necessary for Smart Inverter-enabled DERs to Provide Distribution Grid Services Beyond Smart Inverter Autonomous Functions



Utility investments in systems that can integrate SIs into distribution grid operations are foundational to full realization of DER potential. While SI-enabled DER penetration on the distribution grid is still relatively low overall, investment should begin today to prepare for a high DER penetration future, if utilities and DER customers are to derive maximum value from SI deployment.

First, utilities will need new modeling and distribution power flow capabilities to better forecast the operations of and impacts from SI-enabled DERs, in order to utilize the full benefits of SI functionality. PG&E experienced this need in the EPIC Project 2.02 DERMS demonstration, where software was deployed to allow distribution load flow and state estimation for the demonstration feeders in question. These capabilities enabled advanced modeling and forecasting of distribution grid constraints and automated optimization of DER dispatches in concert with traditional distribution operations equipment to resolve real-time and forecasted issues[34]. SCE is also exploring these advanced capabilities in its EPIC 1 Integrated Grid Project, which will demonstrate power flow optimization with DER participation and DER operational data integration into operations[35]. Advanced DMS software deployments will be key to safely and reliably accounting for DERs in distribution grid operations, and to laying the foundation for active DER management to enable distribution grid services.

Second, regardless of DER integration needs, phase identification improvements will be necessary to enable phase balancing with SI-enabled DERs and improve situational awareness for the grid operator[36]. These improvements will rely on investments in hardware, communications infrastructure, and analytical software to produce the required phasing data.

Third, additional hardware devices will be required to complement the deployment of SIs as complexity of power flows increases with DER penetration. These include distribution grid devices such as additional line sensors to augment visibility and monitoring of end devices like SIs and Smart Meters.

Finally, current utility operational systems are not yet capable of using advanced SI technology available today, such as SIWG Phase 3 functions, to its fullest extent. Utility investment in ADMS and DERMS software would provide visibility and control of SI-enabled DERs to the utility

[34] This functionality included the ability to calculate forecast DER contributions, to anticipate day-ahead capacity and voltage violations, and to suggest DER re-dispatch mitigation plans.

[35] SCE EPIC 1 Report, Pages, 64-139: https://on.sce.com/2CSLVAv

[36] For more detail, see Appendix I, "Phase Identification Requirements"

and allow DERs to fully realize their value through dynamic management for distribution grid services.

2.5.1. Enhanced Communication Infrastructure and Interoperability is Critical

To ensure grid safety and reliability, SI communications should be designed for reliable, durable and secure operation. California IOU experience has uncovered challenges to SI integration in two key areas related to communication:

1) Communication Infrastructure: Communications to DER assets at the grid edge currently may not provide the necessary reliability or availability for utilities to rely on these assets for distribution grid services at scale.
2) Communication Protocols: Utility demonstration experience has highlighted that for some DER use cases beyond current Rule 21 requirements, communication protocols such as IEEE 2030.5 may need to be customized with additional capabilities when implementing utility and aggregator interactions.

In multiple IOU residential demonstrations, communication to residential SIs via customers' home internet in combination with ZigBee was not always reliable[37]. Similarly, satellite and cell communication to commercial SIs in PG&E's EPIC 2.03A Location 2 experienced frequent and prolonged outages that led the aggregation software to fail, resulting in an inability to remotely change SI settings or download DER data. While several factors contributed to these challenges, more reliable and standardized communication performance would be recommended for SI-enabled DERs to participate actively in grid services at scale (e.g. if the use cases require active control, such as sending real or reactive power set points).

One potential approach to account for unreliable communication in some DER assets could be to build in a probabilistic expectation for asset availability. Since no network consisting of many geographically dispersed nodes (e.g. AMI or SCADA) will have 100% uptime, it may be unrealistic to expect that an aggregation of SI-enabled DERs will be as reliable as a bulk generator[38]. A probabilistic approach could factor in the likelihood that some proportion of assets will not be able to respond to a grid need, and adjust an aggregator or utility DER dispatch signal accordingly. Any communication reliability and performance standards that emerge should also factor in the use case: are the DER assets primarily operating autonomously (with infrequent remote settings changes), or do they need to be available on-demand for active control cases such as capacity or reliability?

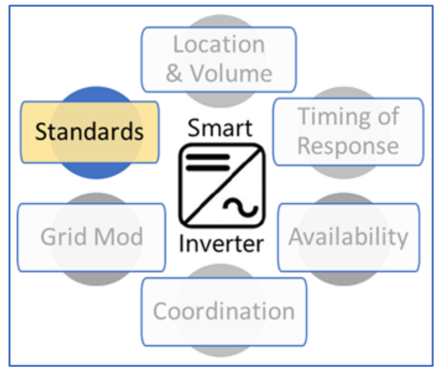
While protocols for communicating to SI-enabled DERs exist, they are still evolving, and there is not yet an "out-of-the-box" aggregator solution that allows seamless interoperability between DERs, aggregators, and utilities. The IOUs have found that the IEEE 2030.5 protocol is a

[37] SCE's Irvine Smart Grid Demonstration also found that communication to other home area network (HAN) devices via Zigbee was challenging: https://bit.ly/2q2xaCv

[38] Bulk generators on the transmission system are typically designed with redundant systems for high reliability.

powerful tool for implementing advanced SI functions as defined by Rule 21. However, extensions to 2030.5 were required in IOU demonstrations for certain active control (DERMS) use cases, for example bidding DER capabilities into a test-scale distribution capacity market[39]. Such customization when implementing DER control functions beyond the current Rule 21 requirements could be a barrier to scalability and interoperability and may contribute to differing interpretations of the same instruction or command between utilities and aggregators. As SIs and DER use cases continue to evolve and DER aggregations begin responding to dynamic grid needs, testing and certification procedures for the 2030.5 protocol should continue to be updated to move the industry towards a more standardized "plug-and-play" state.

2.6. Standards, Certifications, and Field Implementation are Critically Important



As many U.S. regions transition to a high DER penetration world, the standardization of SI technical functions, software and hardware can provide certainty to utilities and aggregators that the devices can be operated safely and consistently across a range of grid conditions. Consistent standards across geographic regions have allowed for reduced cost and complexity for manufacturers, and helped streamline the interconnection process.

As requirements for new advanced functions like communications, Volt-Watt and Frequency-Watt go into effect, it is critical that certification and testing procedures are clear and rigorous and that SIs are properly configured to comply with Rule 21 upon installation. As advanced SI functionality is phased in over 2017-2019, separate standards have emerged for certifying and testing different Smart Inverter functions[40]. This phased implementation has created complexity for manufacturers in getting Rule 21-compliant SIs to market and for Nationally Recognized Testing Laboratories (NRTLs) to certify SIs[41]. The IOUs recognize that with time and subsequent standard revisions, the certification and testing process will become more streamlined.

After a SI-enabled DER is interconnected per Rule 21 with all required default settings, it is equally important to ensure that the default settings are not subsequently changed in unexpected or unapproved ways so as to invalidate the interconnection agreement. California IOU lab and field experience has shown that more consistent manufacturer product

[39] Specifically, PG&E's EPIC 2.02 DERMS and EPIC 2.03A SI demos found that 2030.5 lacked the ability to support market functions, scheduling, and confirmation that SI curves were running after command execution.

[40] The SunSpec Common Smart Inverter Profile (CSIP) provides testing procedures for the Phase 2 and 3 SIWG functions while UL 1741 defines test standards to the Phase 1 utility interactive inverter requirements of IEEE 1547. IEEE 1547.1 and UL 1741 for 1547.1 will likely not be issued until January 2020. Certification of SIWG Phase 1 functions is still covered by the UL 1741-SA test specification.

[41] Appendix H summarizes the complex landscape of SI standards and test procedures.

documentation, user-friendly SI user interfaces, and field verification by installers are also needed to ensure SIs are correctly configured when installed.

In both field and lab settings, the California IOUs have observed variability in different manufacturers' software and hardware performance[42]. Challenges encountered by the IOUs include differences in performance among products for pre-defined Volt-VAr/Volt-Watt curves, implementation of function priority, and SI response to remote commands and variable grid conditions. For example, recent IOU lab testing found that one manufacturer's new SI unit failed to initialize, another stopped functioning upon executing the latest Rule 21 firmware update, and a third shut down unexpectedly under normal operating conditions. IOU field experience also shows that many installers have not been able to properly set all SI parameters to comply with Phase 1 SIWG SI requirements that came into effect in September 2017. Manufacturers should standardize SI feature names in user interfaces and improve documentation to facilitate proper configuration by installers.

Overall, the results from IOU SI demonstrations are promising. However, certain aspects of SI performance require further testing to ensure that manufacturers comply with standards. Prior to implementation of any DER-based distribution grid services or reliability programs, it is essential that aggregator and DER operational and performance requirements are validated to be in place.

2.6.1. Cybersecurity Standards Need to be Developed for Smart Inverters

No national standards currently exist to ensure end-to-end secure implementation of SIs, and aggregator-specific communication protocols for control and coordination are highly variable in their level of security offerings. As such, further testing is required to develop and validate cybersecurity requirements which safeguard against various threat scenarios intended to maliciously operate SIs outside of their expected manner. Cybersecurity requirements should also include the protection of data at rest and in transit, secure over-the-air update procedures, access, authentication and authorization.

While the decision was made to specifically exclude cybersecurity standards from IEEE 1547-2018, cybersecurity standards should be adopted by the industry and integrated into the appropriate SI standards. As other grid-interactive hardware devices (e.g. smart thermostats and IoT routers/gateways) proliferate, these standards should be extended to any such non-SI device that enables communication and control between a DER and a utility or aggregator.

[42] Some of the functions tested were not yet formally required/certified in California. While some of the Smart Inverters tested were compliant with the September 2017 Rule 21 Phase 1 requirement, none had yet been certified to UL-1741SA for Rule 21 Phases 2 and 3 since those requirements go into effect in February 2019.

A key challenge with the current California Common SI Profile (CSIP) is that standards for aggregator communication to SI-enabled DERs are currently out of scope[43]. DER aggregators' highly variable proprietary communications methods are likely to have cybersecurity vulnerabilities that could put both the aggregator and utility (and ultimately the stability of the distribution grid) at risk. New standards to test and certify these proprietary methods for cybersecurity conformity should be developed.

3. Conclusions and Recommended Next Steps

This white paper identifies key factors for the scaled deployment of SI-enabled DERs as an effective and reliable distribution grid resource. These factors include recognizing that distribution service needs that can be cost-competitively met by DERs do not exist everywhere and that DER location and penetration must coincide with those needs when and where they do exist. To realize the full benefits of SI functionality beyond autonomous functions, utilities will need new modeling, control and communication capabilities to better characterize and forecast the operations of SI-enabled DERs, which will require investments in both software and hardware solutions.

To date, the CA IOUs have demonstrated that SI-enabled DERs have the capability to autonomously support secondary voltage and provide some capacity services. This can help to mitigate the impacts of high DER penetration and potentially increase DER hosting capacity in certain areas, avoiding distribution system upgrades and PV-caused voltage violations. The IOUs have found that maturity in SI testing and certification, more robust communication between aggregators and DERs, and improved utility-aggregator coordination are key next steps to support the deployment of SI-enabled DERs as a reliable grid resource in the future.

Future Directions

1) Utilities should continue to assess the capability and cost-competitiveness of SI-enabled DERs to meet distribution grid needs[44]. Additional SI demonstrations at higher DER penetrations are needed to assess SI capability to support voltage and provide other grid services.

2) As DER penetration increases and provides higher levels of bulk system support (displacing existing centrally-controlled generators), national performance certifications should be explored for certain types of DERs that can provide essential reliability services such as frequency regulation[45].

[43] The CSIP currently only covers utility-aggregator communications. For a more detailed discussion of the CSIP/IEEE 2030.5 and potential cybersecurity threat scenarios, see Appendix K

[44] PG&E's EPIC 2.22 "Demand Reduction through Targeted Analytics" project is applying the utility's data resources and industry-leading analytical skills to identify cost-competitive DER portfolios to meet distribution system needs.

[45] See Appendix J "Using SIs for Synthetic Inertia" for more detail.

3) Future SI research and development could explore the capability to interact with other nearby grid support devices independent of a centralized coordination system. Such intelligent, localized control capability could limit DERs' vulnerability to communication outages, increase response time, and otherwise augment autonomous or DERMS/ADMS-enabled active DER control at the grid edge.

With the advancements described in this white paper, continued collaboration between the IOUs and industry partners, and in situations where they are cost-competitive relative to traditional grid upgrades, SI-enabled DERs have the potential to become an effective technology to maintain and potentially enhance the reliability of the electric grid.

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Smart Inverters and DERMS Considerations

Devin Van Zandt
Technical Executive
DER Integration

February 28, 2019

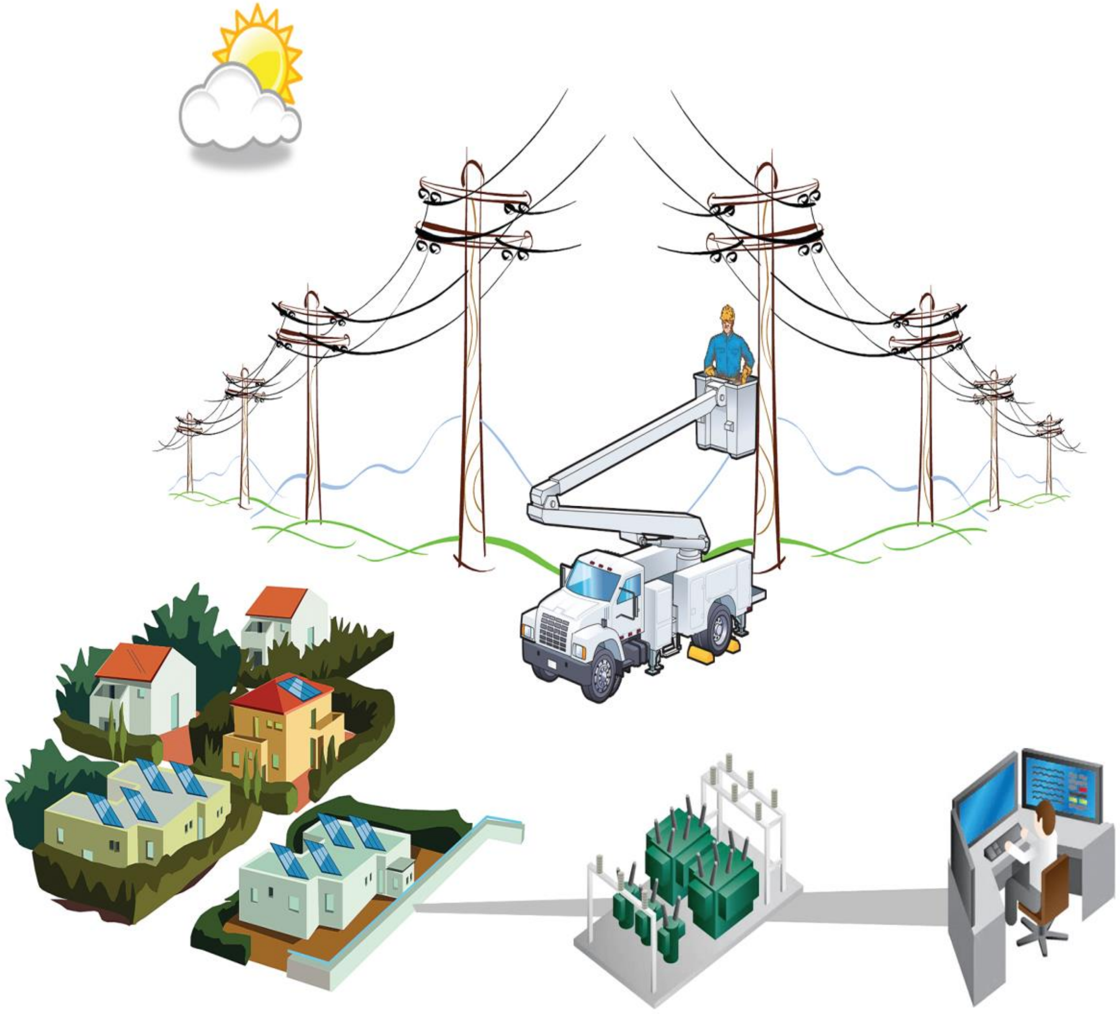
Topics

EPRI Distribution Area Glance

Industry Trends and Observations

Smart Inverter Application Considerations

Quantifying DERMS Impacts



EPRI Distribution Research Area is Growing

P180 – Distribution Systems

Asset Owner Perspective

- Asset management (OH & UG)
- Asset analytics
- New technology & components
- Reliability & resiliency
- Safety

P200 – Operations & Planning

Asset → System

- Advanced planning tools & methods
- Advanced forecasting
- Advanced operations tools (DMS/ DA/FLISR)
- Protection and Control

P174 – Integration of DER

Grid ← DER

- DER technology and grid impact modeling
- Technology assessment
- Monitoring & control/ DERMS
- Integration economics
- Interconnection practices

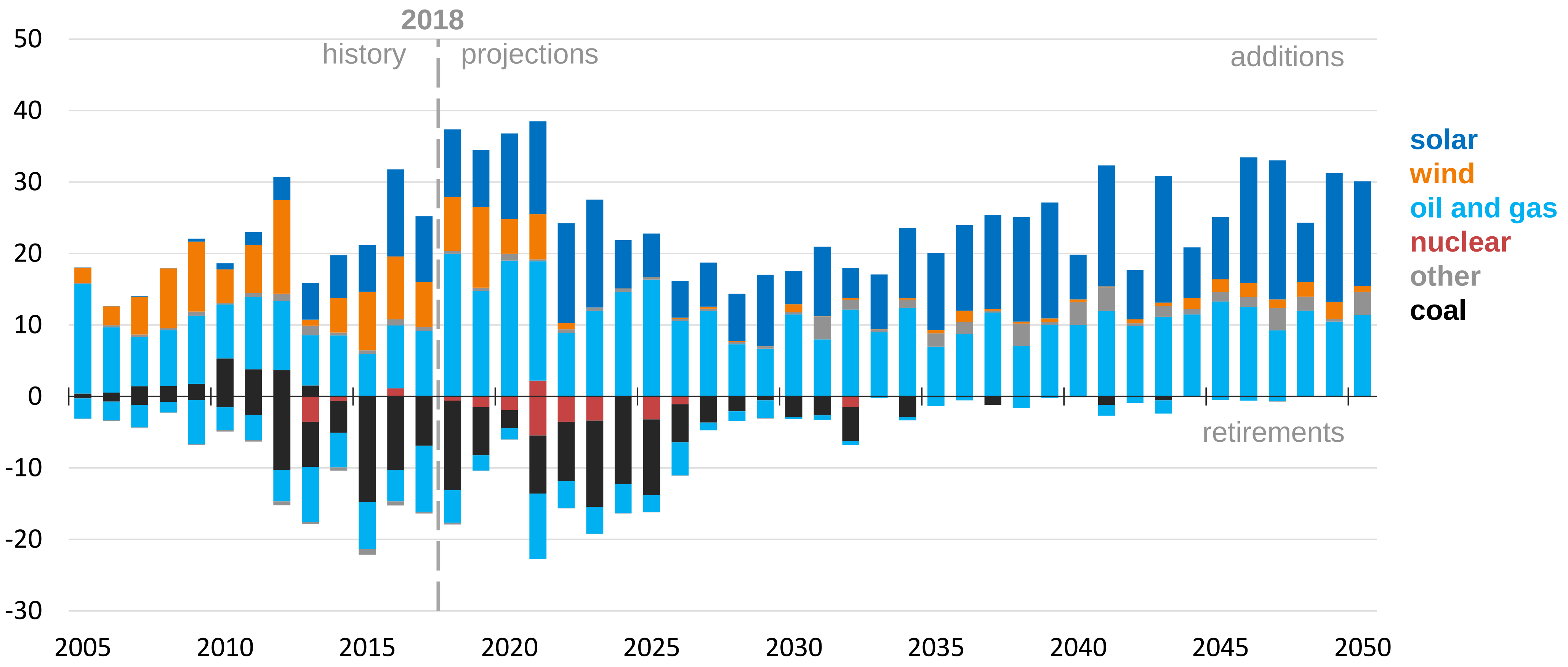
Industry Trends and Observations

Notions about *Solar Power Plants* in February 1976

- Solar-thermal generating stations most promising
- Photovoltaic conversion is attractive but further away in comparison to solar thermal-related technology
- A part-time operation with full time customers needing 24/7 availability
- Capacity displacement is a concern
- Storage may be the key

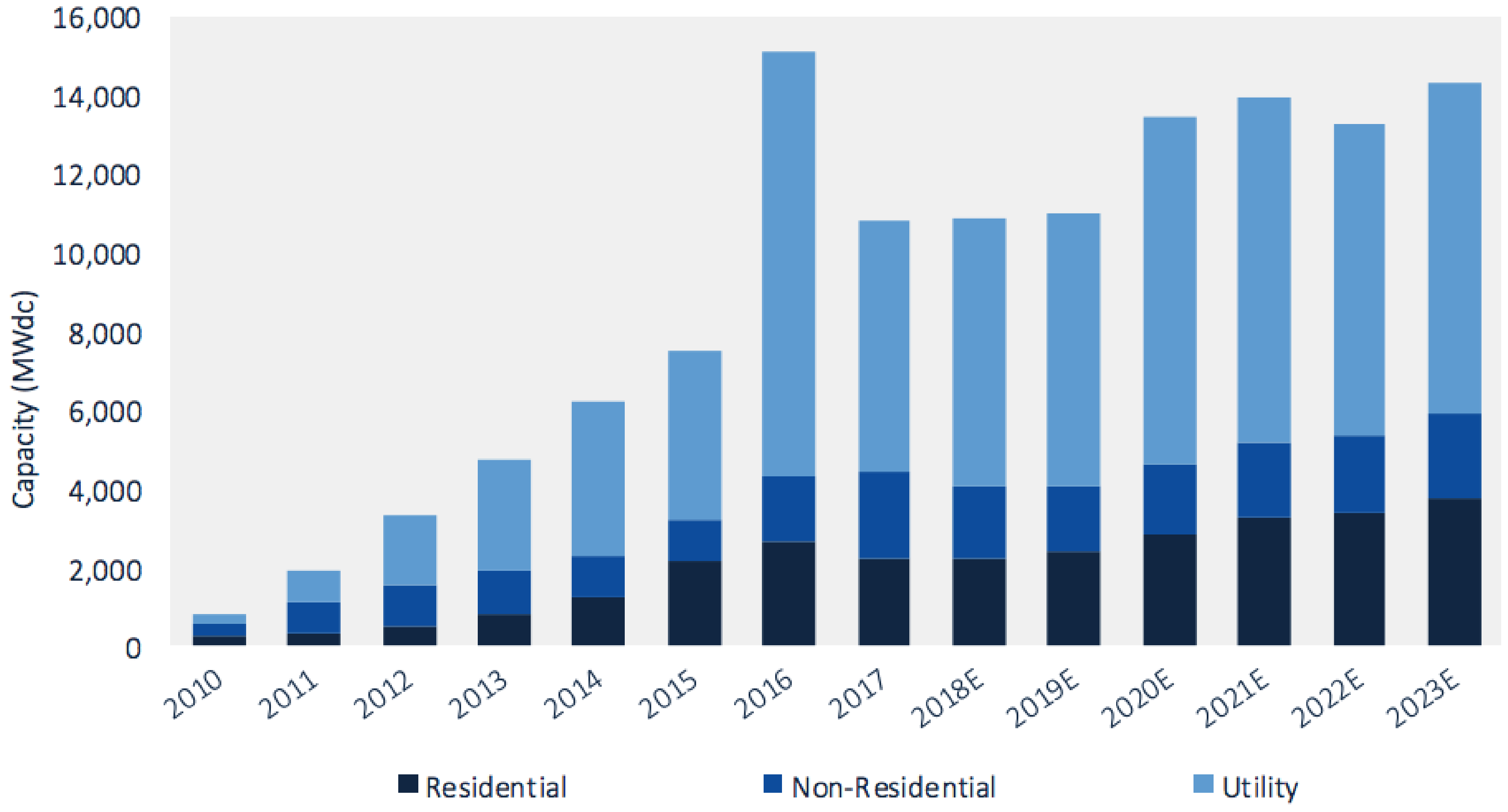
Outlook: 1-2% of the nation's electric power capacity by the year 2000

Annual electricity generating capacity additions and retirements (GW)



www.eia.gov/aeo

PV Installation Growth, total > 58GW



Resource: Courtesy of GTM Research

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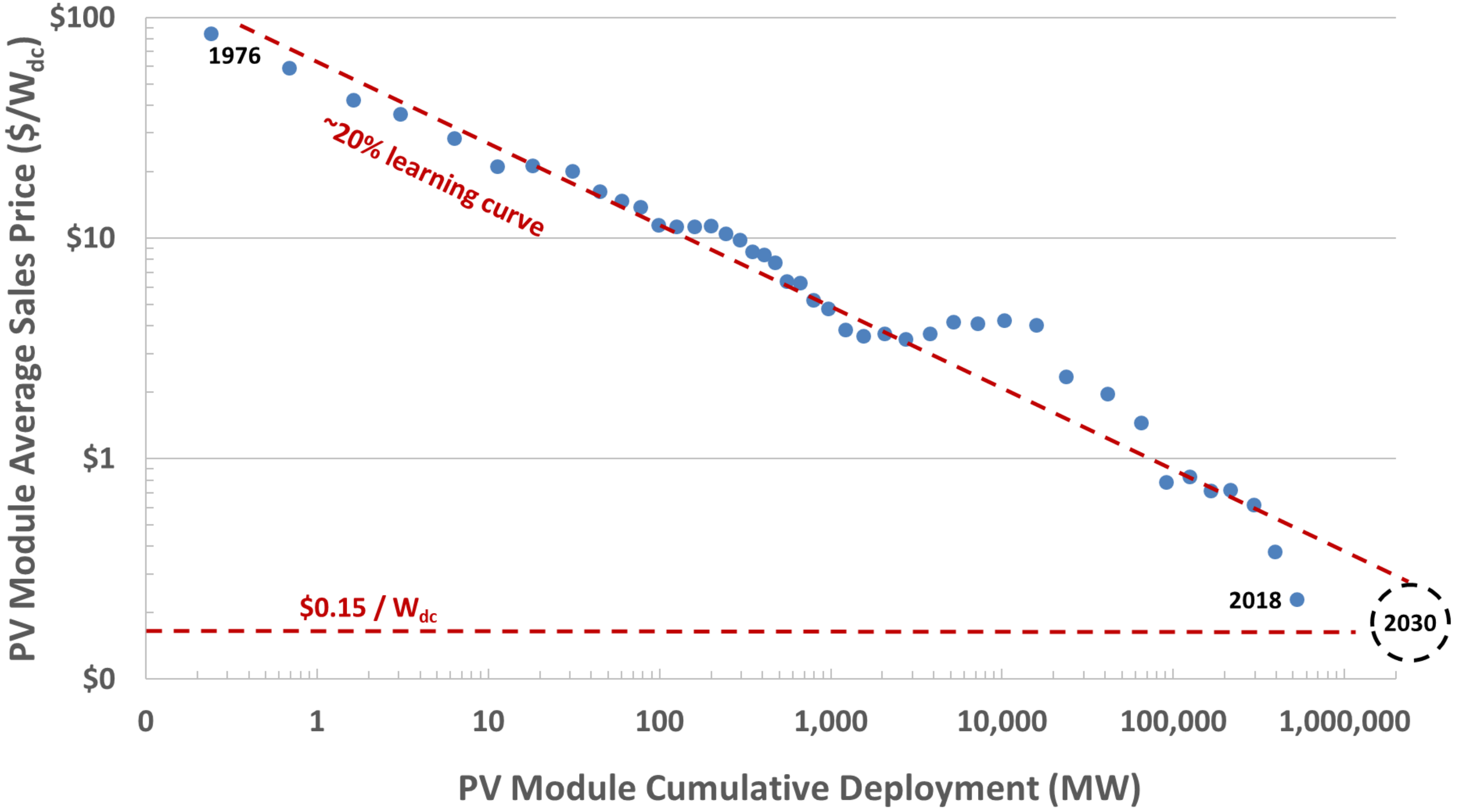
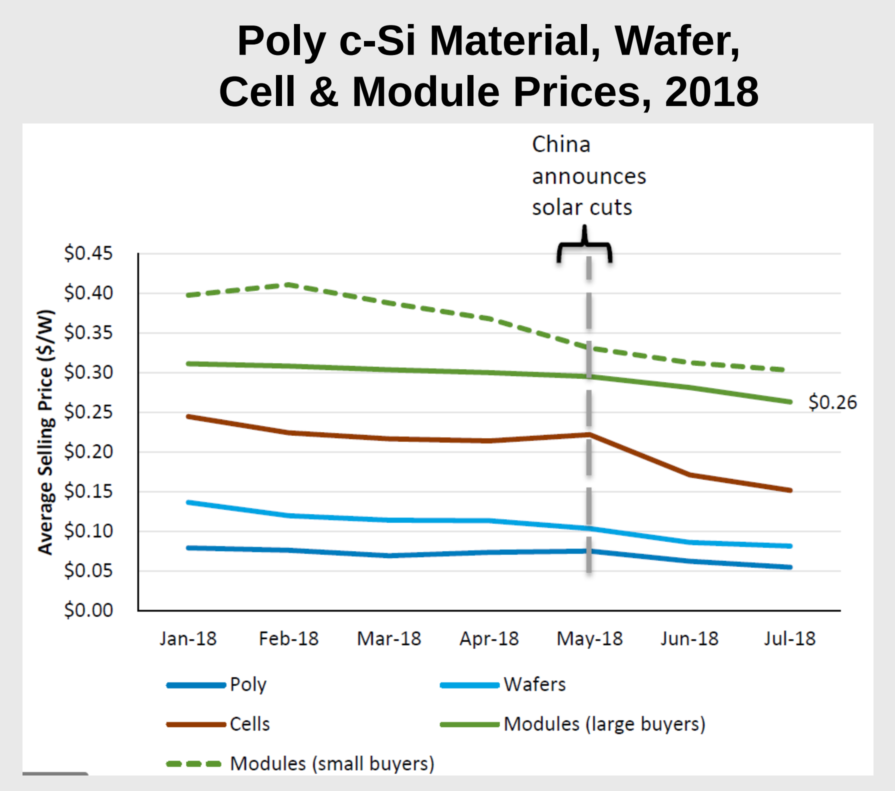
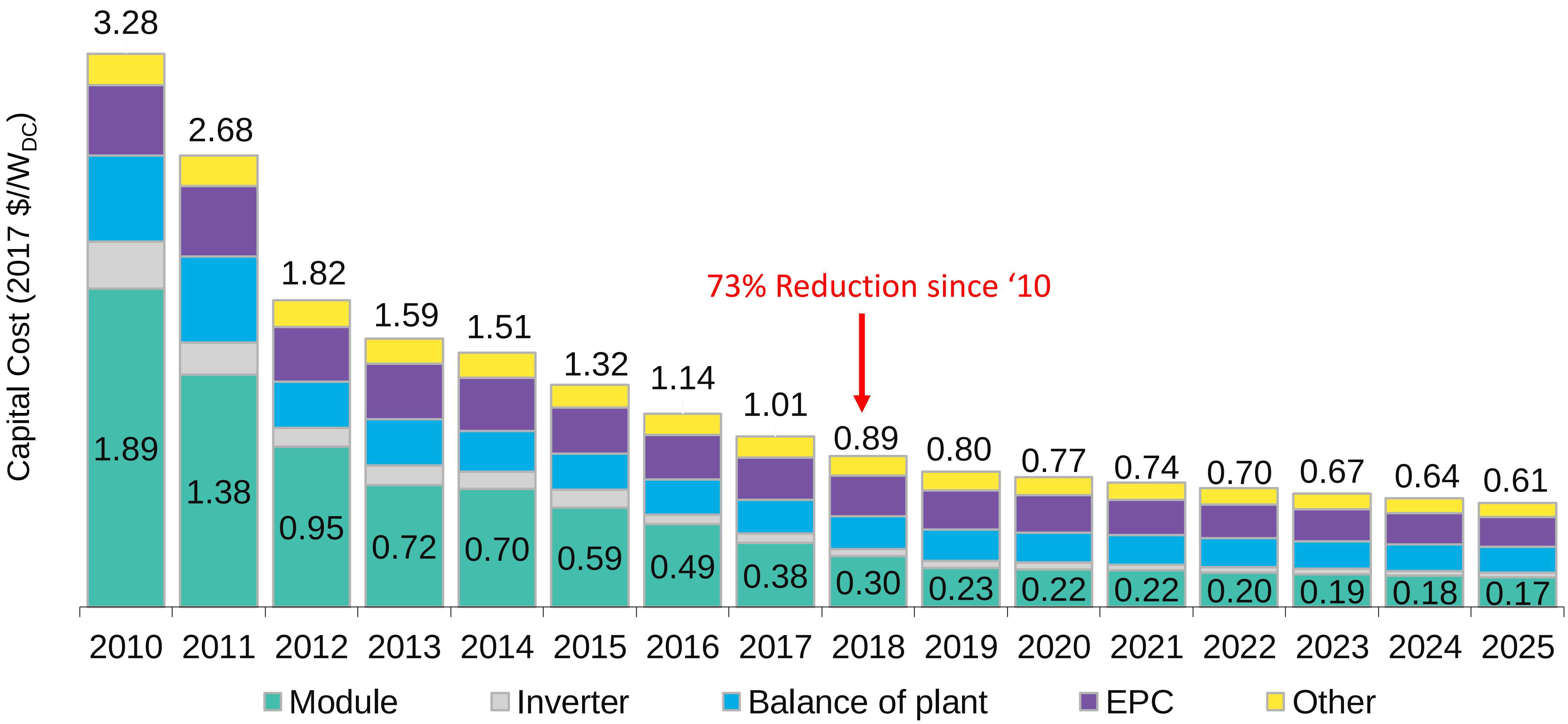
PV Module Pricing Since 1976 (2018 Constant $) & in 2018





Data Sources: BloombergNEF (November 2018); GTM; International Technology Roadmap for Photovoltaic (ITRPV), 2018; BloombergNEF, NEO 2017; IEA, "World Energy Outlook 2017 (New Policies Scenario)"; NREL "Q1/Q2 2018 Solar Industry Update" (August 2018)

Utility-Scale PV Capital Cost History & Forecast, 2010-25e

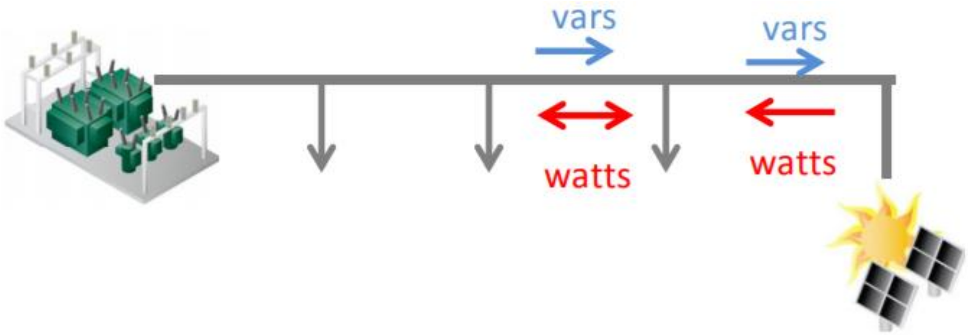


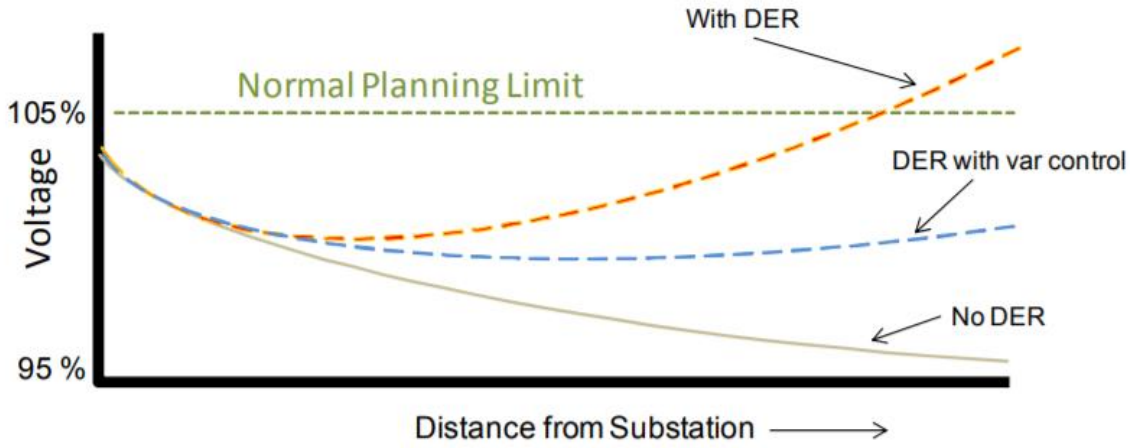
Credit: BloombergNEF, "4Q 2018 Global PV Market Outlook," November 2018

Smart Inverter Considerations

EPRI Smart Inverter Work

- Significant involvement in industry groups (IEEE, CIGRE, etc.)
- Convener of the Smart Inverter Interest Group
- Developing guidelines for smart inverter settings
- Software tools and methods for evaluating the best settings





The DER Interconnection Standards Evolution

Minimal Impact to Grid

IEEE 1547-2003

DER is tripped during abnormal system conditions to avoid interaction with grid and potential safety issue

Interim Solution

IEEE 1547a-2014

Provides for voltage and frequency ride-through capability and also voltage regulation. Not a requirement.

Grid Supportive

IEEE 1547-2018, CA Rule 21, HI Rule 14H

Requires voltage and frequency ride-through capability and advanced voltage regulation functions

California Rule 21 Overview

- Electric Tariff Rule 21, Section Hh
- Phase 1 - Autonomous Functions
  - Capability required by September 8, 2017
- Phase 2 – Communication Protocols
  - Capability required by March 1, 2018 or 9 months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognized communication protocol certification test standard
- Phase 3 – Advanced Functions
  - Timing undefined
  - May include alarms and monitoring
  - Many proposed functions already exist in latest IEEE 1547-2018 (e.g. Dynamic Reactive Current Mode is optional in 1547)

Pacific Gas and Electric Company
U 39
San Francisco, California

	Revised	Cal. P.U.C. Sheet No.	40278-E
Cancelling	Revised	Cal. P.U.C. Sheet No.	36812-E

ELECTRIC RULE NO. 21 Sheet 1
GENERATING FACILITY INTERCONNECTIONS

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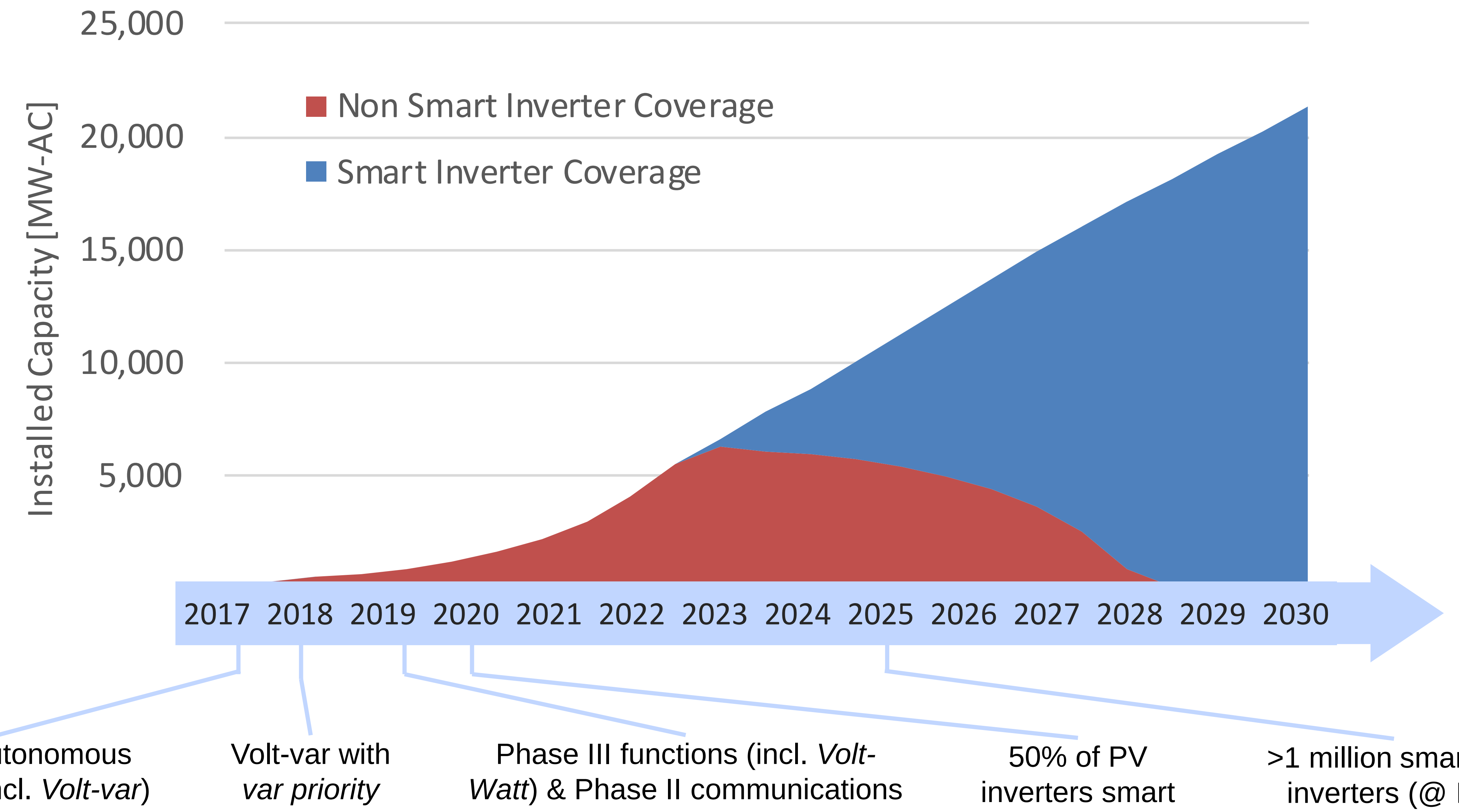
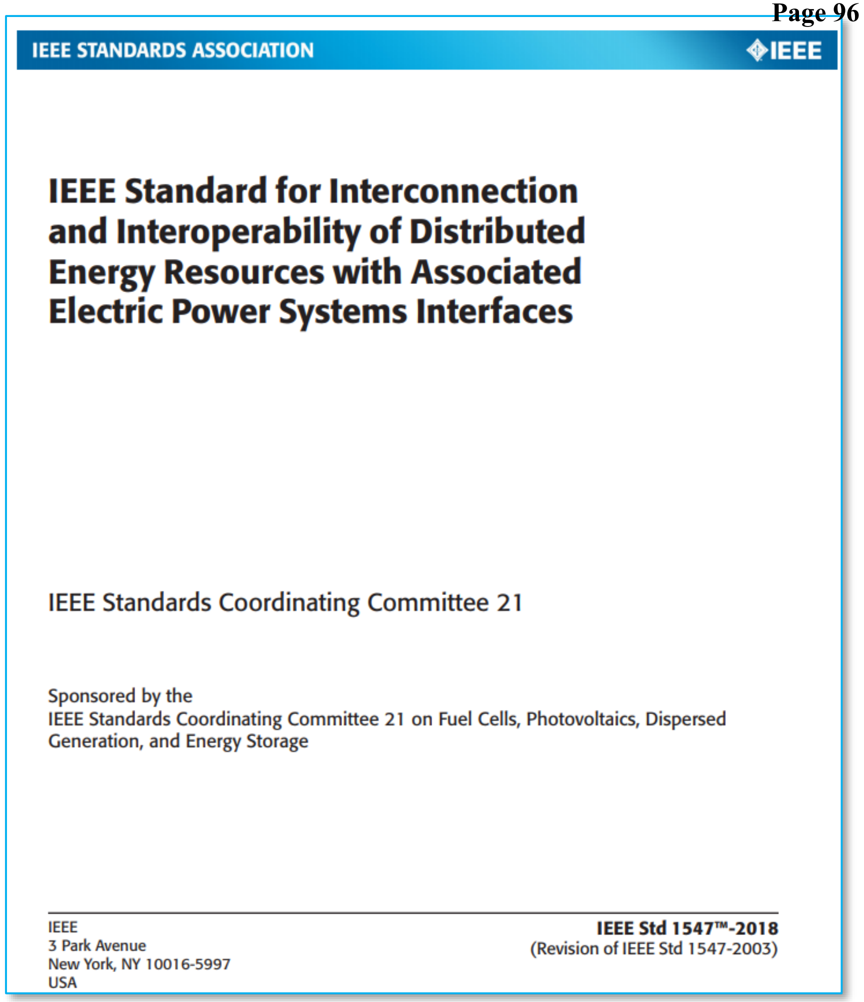
Smart Inverters in BTM PV in California



 www.epri.com

IEEE 1547-2018 Standard

- Approved in February of 2018
- Significant update to previous version
- Very comprehensive and complex standard
- Requires DER to have new capabilities/functions to improve "grid friendliness"
- DER required to have some capabilities of bulk generation resources
- Standard addresses DER operation under both abnormal and normal conditions
- Default settings for functions are provided in the standard
- Testing standard currently under development
- IEEE 1547-2018 compliant (Tested to IEEE 1547.1) inverters will likely become available in 2020-21
- California Rule 21 and Hawaii Rule 14 inverters are available today



IEEE STANDARDS ASSOCIATION   IEEE

IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

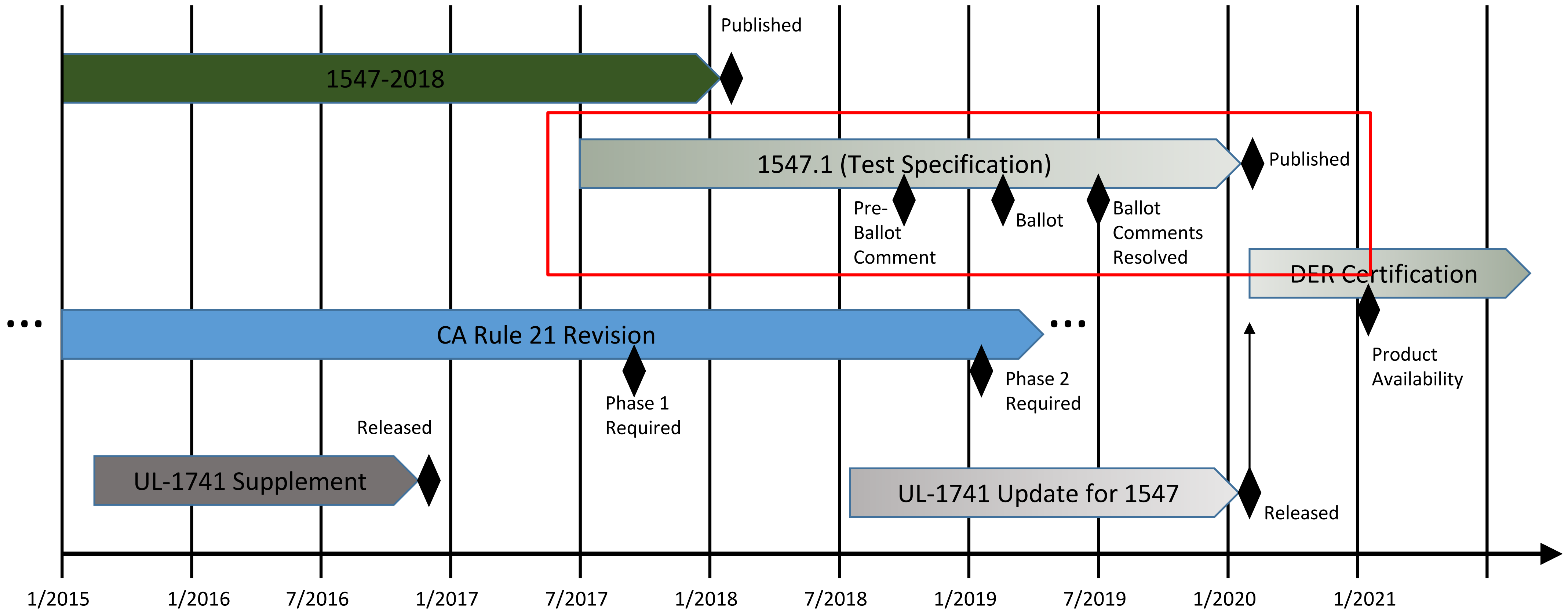
IEEE Standards Coordinating Committee 21

Sponsored by the
IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1547™-2018
(Revision of IEEE Std 1547-2003)

Timeline for Certified Devices



There is uncertainty with regard to the completion date for IEEE P1547.1, the Update of UL 1741, and the DER certification for equipment fully compliant with IEEE Std 1547-2018.

Interconnection Standards Adoption Roadmap Considerations

- UL 1741 certified inverters may also be UL 1741 SA certified!
  - That requires to pay attention to the functional settings of any inverter on the market
- Today, UL 1741 SA certified inverters are shipped either with
  - IEEE Std 1547-2003 settings (Generally the default)
  - IEEE Std 1547a-2014 settings
- That reduces the need of coordination with existing protection coordination
  - Settings other than the ones based on the old IEEE 1547 need to be changed in the field.

Adoption of CA Rule 21 and Hawai'ian Rule 14H by inverter certification per UL 1741 (SA).

Stopgap solution for **adoption of parts of IEEE Std 1547-2018** by inverter certification per UL 1741 (SA).

Full adoption of IEEE Std 1547-2018.

Question from **distribution** perspective:

Early need to increase hosting capacity?

Question from **transmission** perspective:

Early need to address bulk system reliability?

Nameplate Labeling of UL 1741 SA Certified Inverters

"Utility Interactive"

- Traditional UL1741
- IEEE 1547 & 1547.1 (1st ed.) Interconnection Requirements

"Grid Support Utility Interactive"

- UL 1741 SA Grid Support Functions
- Source Requirements Documents like CA Rule 21, Hawai'ian Rule 14H, IEEE Std 1547-2018 (2nd ed.)

"Special Purpose Utility Interactive"

- Specific Manufacturer / Utility Defined UL Verified Compliance
- Custom Source Requirements Documents

UL Certification:

- Grid Support, Utility Interactive Product

Scope:

- Safety & Electric Shock Certification to UL1741 including UL 1741 SA for grid support and general grid interconnection per IEEE 1547

Includes Testing to Verify:

- 1.UL 1741 electric shock/fire tests
- 2.UL 1741 SA grid support tests
- 3.Unique tests of IEEE 1547 for general grid interconnection not covered by UL 1741 SA tests, as needed?

Deliverable:

- UL Certification as a Grid Support Utility Interactive product

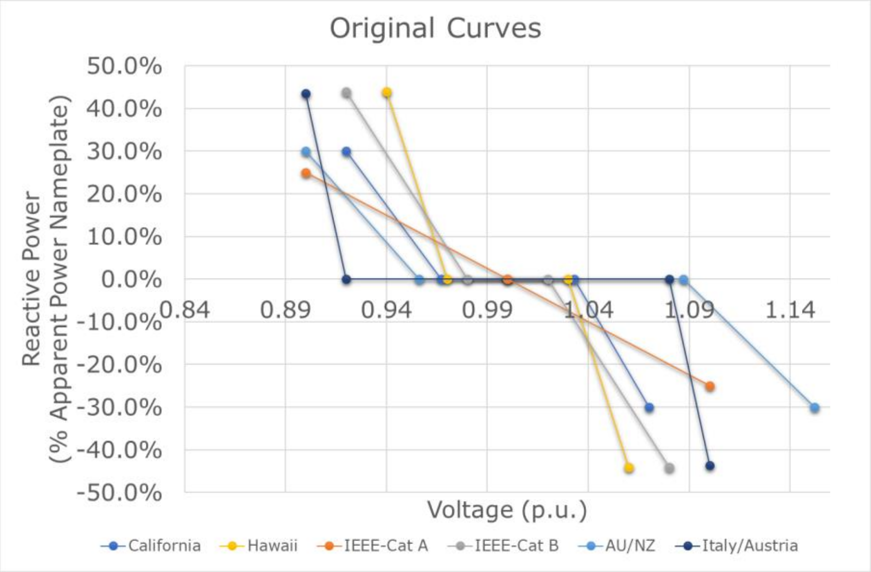
Consolidated Chart of Standard Capabilities

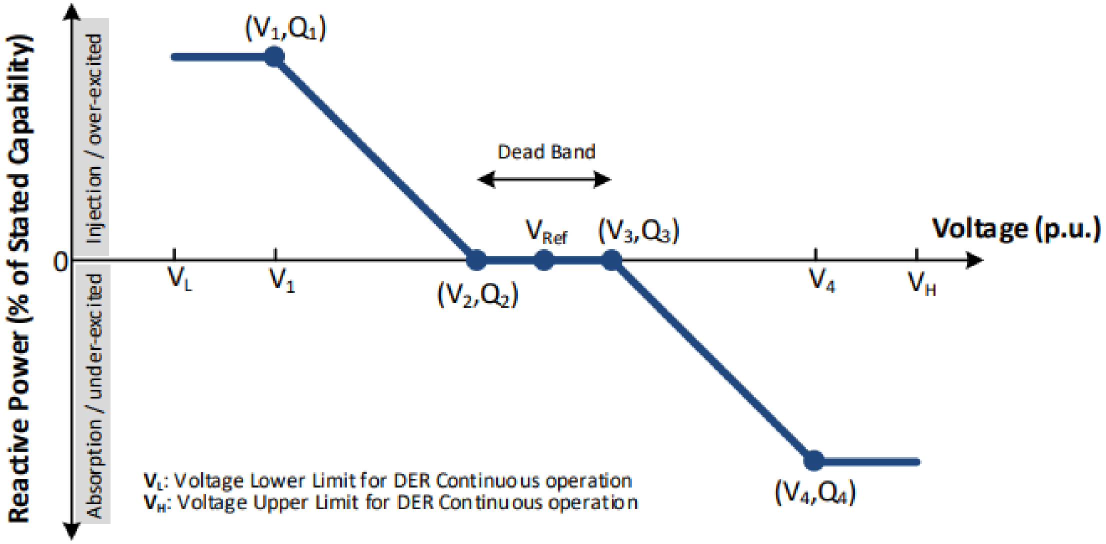
Standards for DER		Listing/ Certification			Interconnection Standards			State/ PUC/Utility	
								CA	HI/HECO
Function Set	Advanced Functions Capability	UL 1741	UL 1741(SA) 2016	IEEE 1547.1 -201?*	IEEE 1547-2003	IEEE 1547a-2014	IEEE 1547-2018	Rule 21 (Phases)	Rule 14H & UL SRDv1.1
All	Adjustability in Ranges of Allowable Settings			Δ		√	‡		
Monitoring & Control	Ramp Rate Control		Δ					‡ (P1)	‡
	Communication Interface			Δ			‡	‡ (P2)	‡
	Disable Permit Service (Remote Shut-Off, Remote Disconnect/Reconnect)			Δ			‡	‡ (P3)	‡
	Limit Active Power			Δ			‡	‡ (P3)	
	Monitor Key DER Data			Δ			‡	‡ (P3)	
Scheduling	Set Active Power							[‡ (P3)]	
	Scheduling Power Values and Models							‡ (P3)	
Reactive Power & Voltage Support	Constant Power Factor	√	Δ	Δ	√	√	‡	‡ (P1)	X
	Voltage-Reactive Power (Volt-Var)		Δ	Δ	X	√	‡	‡ (P1)	‡
	Autonomously Adjustable Voltage Reference			Δ			‡	!!!	!!!
	Active Power-Reactive Power (Watt-Var)			Δ	X		‡		‡
	Constant Reactive Power	√		Δ	√	√	‡		
	Voltage-Active Power (Volt-Watt)		Δ	Δ	X	√	‡	‡ (P3)	‡
	Dynamic Voltage Support during VRT						√	[‡ (P3)]	
Bulk System Reliability & Frequency Support	Frequency Ride-Through (FRT)		Δ	Δ			‡	‡ (P1)	‡
	Rate-of-Change-of-Frequency Ride-Through			Δ			‡	!!!	!!!
	Voltage Ride-Through (VRT)		Δ	Δ			‡	‡ (P1)	‡
	Voltage Phase Angle Jump Ride-Through			Δ			‡	!!!	!!!
	Frequency-Watt		Δ	Δ	X	√	‡	‡ (P3)	‡
Other Advanced DER Functions	Anti-Islanding Detection and Trip			Δ			‡	‡ (P1)	‡
	Transient Overvoltage						‡		‡
	Remote Configurability						‡	‡ (P2)	‡
	Return to Service (Enter Service)						‡	‡ (P1)	‡

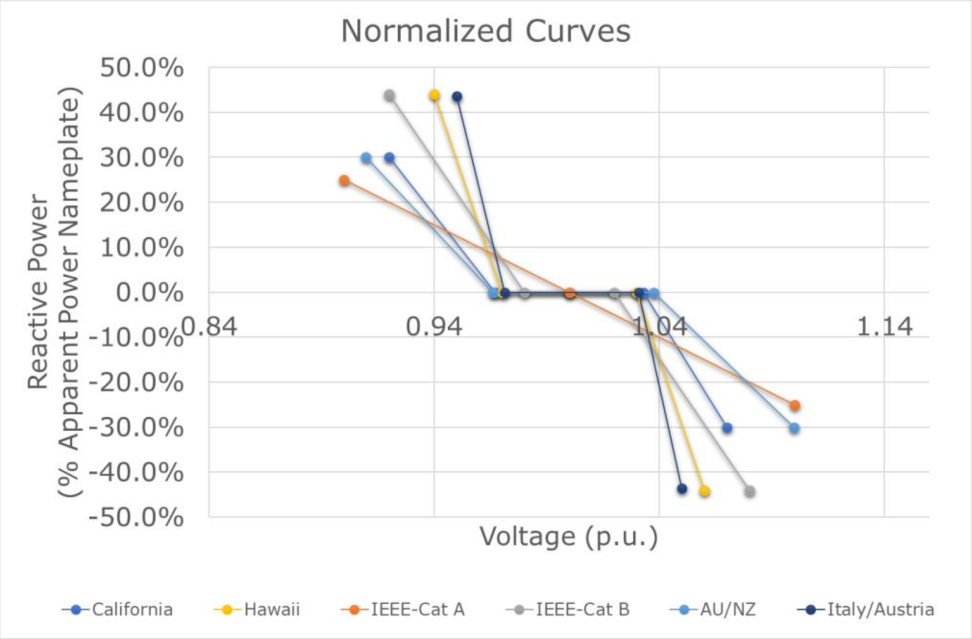
Legend: X Prohibited, √ Allowed by Mutual Agreement, ‡ Capability Required, Δ Test and Verification Defined Source: EPRI.
[…] Subject to clarification of the technical requirements and use cases, !!! Potentially Important Gap

Please contact us for any suggested updates to this table.

Comparison of Default Volt-var Settings for Several Standards





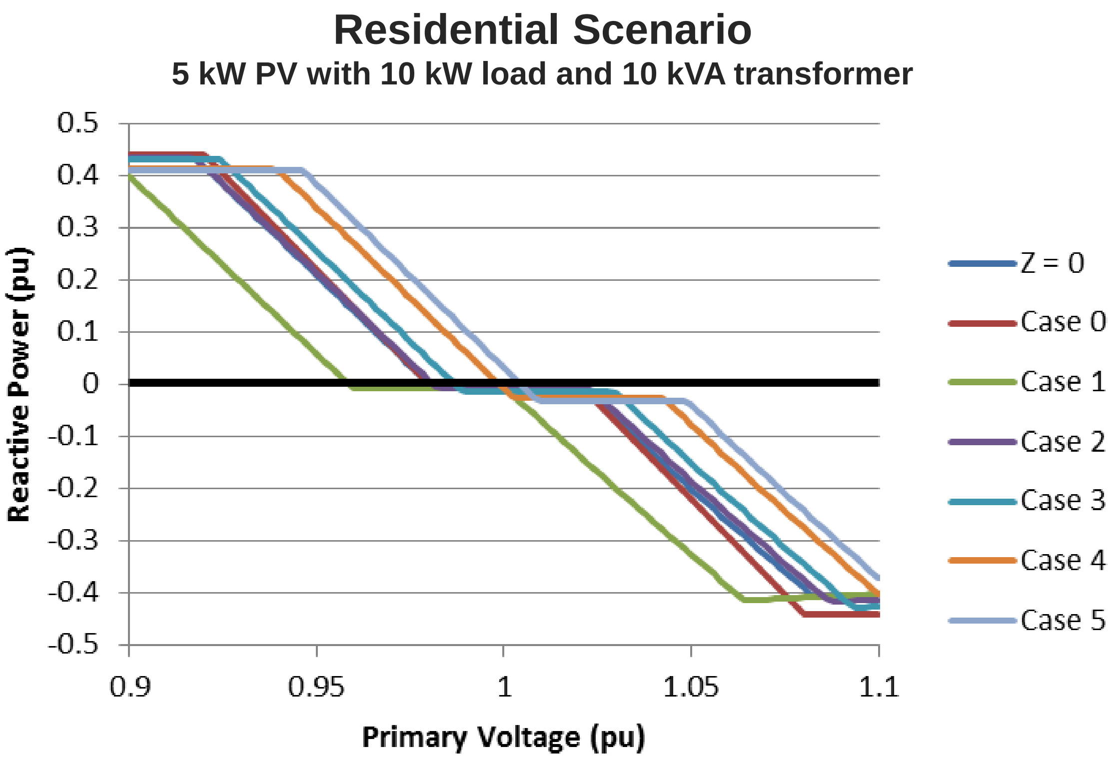


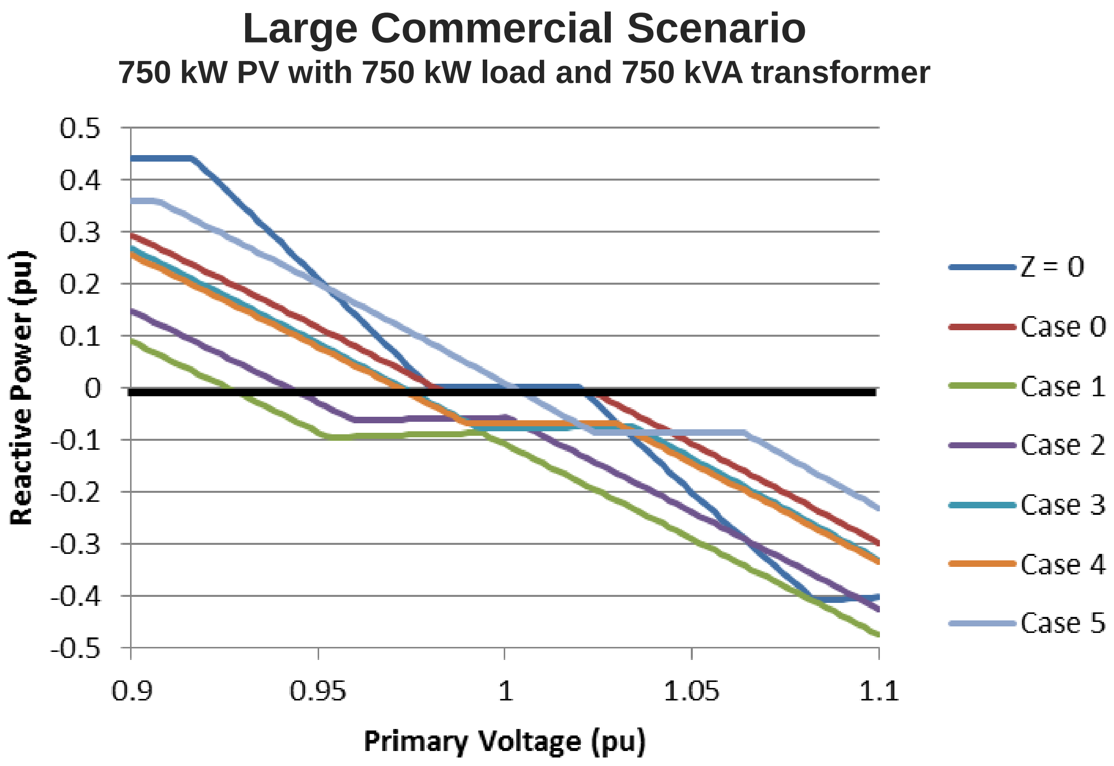
Default Volt-var Settings	USA				Australia		
	General		California	Hawaii		Italy	Austria
	IEEE 1547		CA 21	HI 14	AS/NSZ 4777.2	CEI 0-16	TOR D4
	Cat A	Cat B					
V_1	0.9	0.92	0.92	0.97	0.9	0.9	0.9
Q_1	+25%	+44%	+30%	+44%	+30%	+43.6%	+43.6%
V_2	1	0.98	0.967	0.97	0.956	0.92	0.92
Q_2	0	0	0	0	0	0	0
V_3	1	1.02	1.033	1.03	1.087	1.08	1.08
Q_3	0	0	0	0	0	0	0
V_4	1.1	1.08	1.07	1.06	1.152	1.1	1.1
Q_4	−25%	−44%	−30%	−44%	−30%	−43.6%	−43.6%

EPRI ELECTRIC POWER RESEARCH INSTITUTE

Volt-VAR Regulation

Effective default volt-var curve at the primary side for DER sensing POI voltage



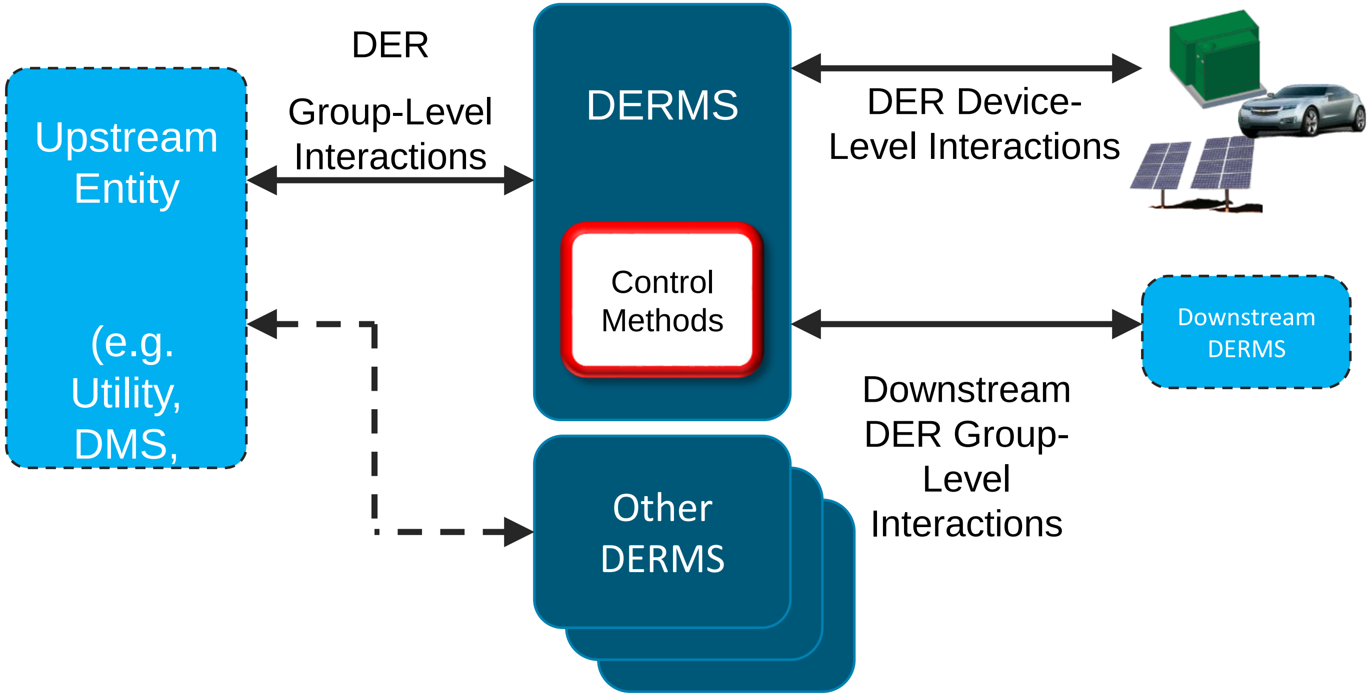


- Uncontrolled factors create uncertainty in primary-side regulation
- Reactive power follows the general trend of the default (IEEE 1547) curve

Quantifying DERMS Impacts

Hosting Capacity Impact of DERMS Reactive Power Control
Overview

- First in a series of projects to evaluate and quantify the technical benefits of DERMS
- Develop methodology and perform analysis to quantify the impact of DERMS reactive power control on hosting capacity
- Determine when and where DERMS has value in comparison to fixed power factor
- Provide guidance regarding the potential value streams for DERMS



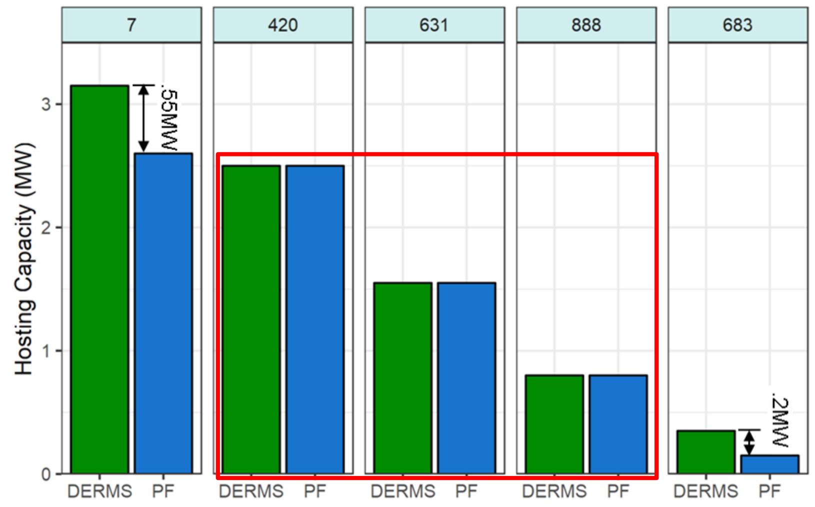
Tightly coupled with DERMS WG

Hosting Capacity Impact of DERMS Reactive Power Control

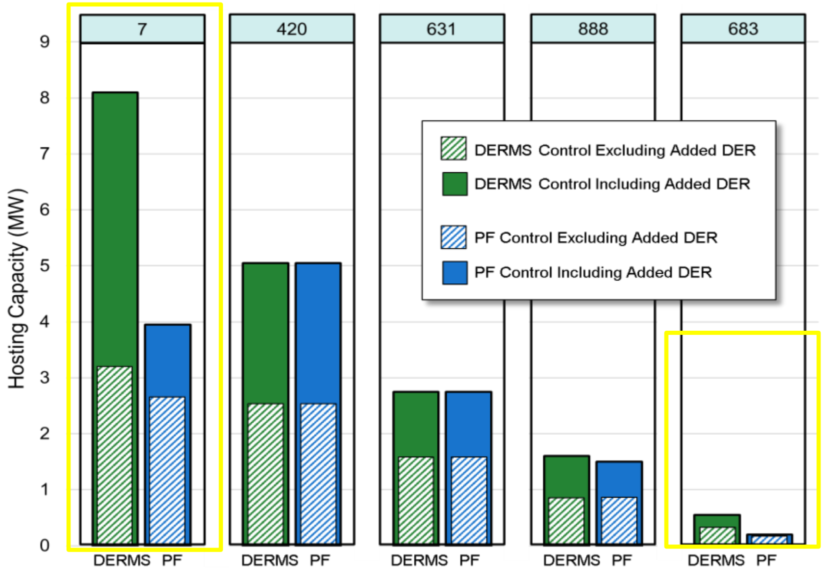
Some Findings

- On 3 (420, 631, 888) of the 5 feeders, DERMS control and fixed PF result in the same HC because both modes are capable of operating the DER at max inductive reactive power
- On 2 (7, 683) of the feeders, DERMS control produces a higher HC because the fixed PF function cannot be set at max reactive power without causing undervoltage issues.
- All feeders show incremental HC gain from reactive power support in comparison to unity PF
- Feeders 7 and 683 show some improvement from DERMS over fixed PF (15% and 133% respectively). With inclusion of DER reactive power control for new additions, feeder 7 HC improves by 105% and Feeder 683 improves by 21%.
- HC improvements vary widely depending on location on feeder

- Sensitivity: Reactive power control for added DER
  - Considering new DER as operating at unity PF is unlikely
  - Limited benefit for most feeders, but feeder 7 exhibits significant benefit
  - Marginal benefit for feeder 888 where none was previously observed



Comparison of Incremental Hosting Capacities from DERMS and Fixed PF

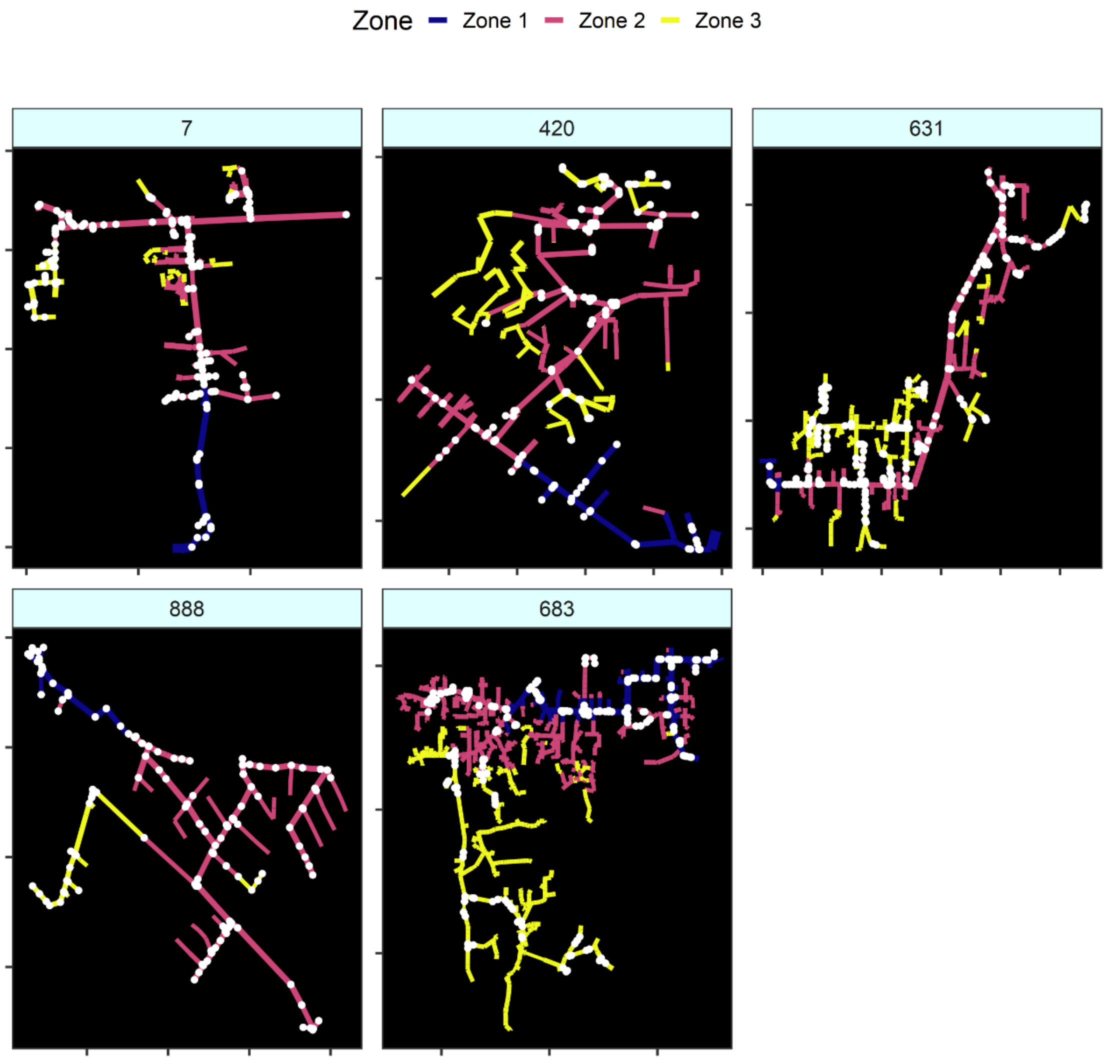


Inclusion of Added DER in Reactive Power Control

Hosting Capacity Impact of DERMS Reactive Power Control

Future Research

- Analyze more feeders to understand the probability and magnitude of HC increases with DERMS
- Evaluate and compare with other DERMS control strategies
- Analyze additional objectives:
  - Reduced losses and DER hitting var limits through lower average reactive power levels
  - Improving alignment with DA, tap operations, CVR
- Validate results against detailed time-series analysis and inclusion of control for added DER
- Examine the impacts of a different composition of existing DER (managed vs. autonomous vs. fixed)
- Explore different DER grouping methods
  - Benefit of more (smaller) groups vs few large groups?
  - Locational dispatching advantages



Together…Shaping the Future of Electricity

DRAFT

AEIC DER Fall Meeting

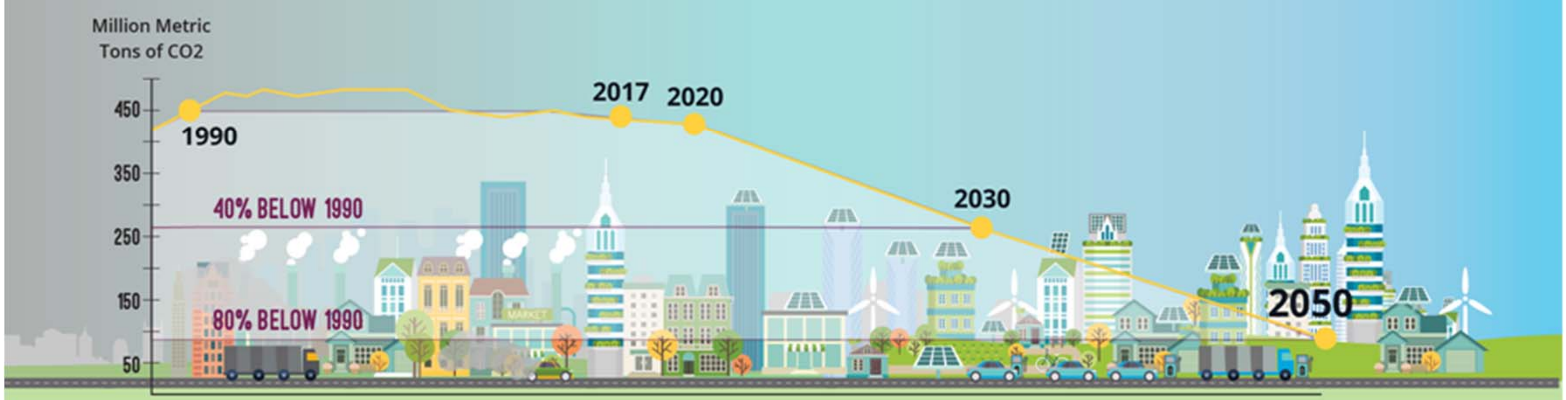
Vibhu Kaushik, Director of Grid Technology & Modernization
Southern California Edison

August 22, 2019

Southern California Edison by the Numbers

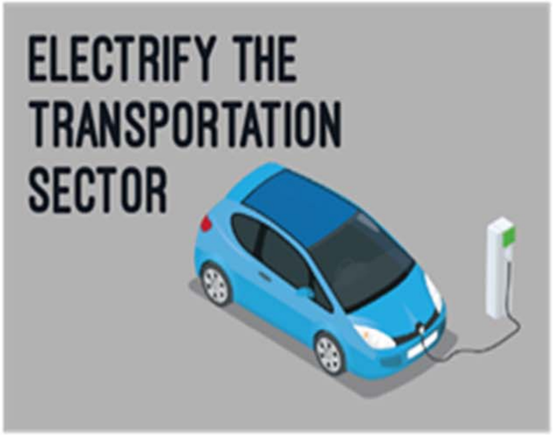
California goals to improve emission levels

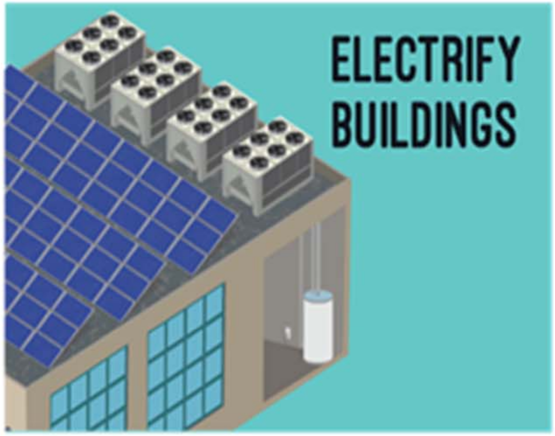
- California set a goal to **reduce emissions 40%** below 1990 levels **by 2030**, and 80% by 2050.
- Governor Brown's Executive Order B-48-18 increases the state target for zero-emission vehicles to 5 million by 2030.



If we want to get to **zero emissions**, eventually we have to **replace** many of the things we rely on today that require combustion.

SCE's Clean Power & Electrification Pathway





Embrace disruption. And electrify.

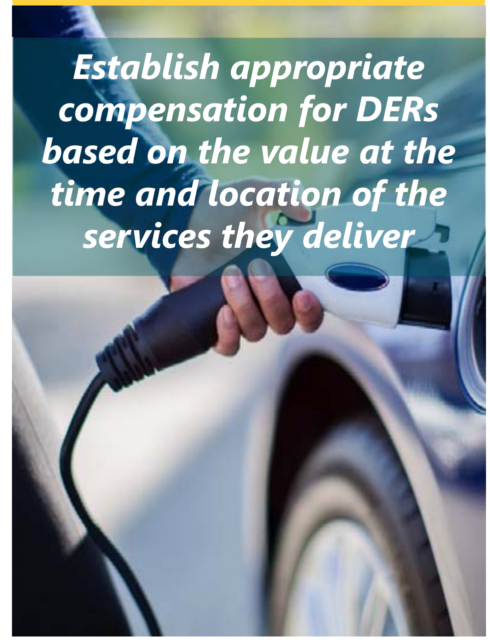
SOUTHERN CALIFORNIA EDISON
Energy for What's Ahead℠

Role of the Utility

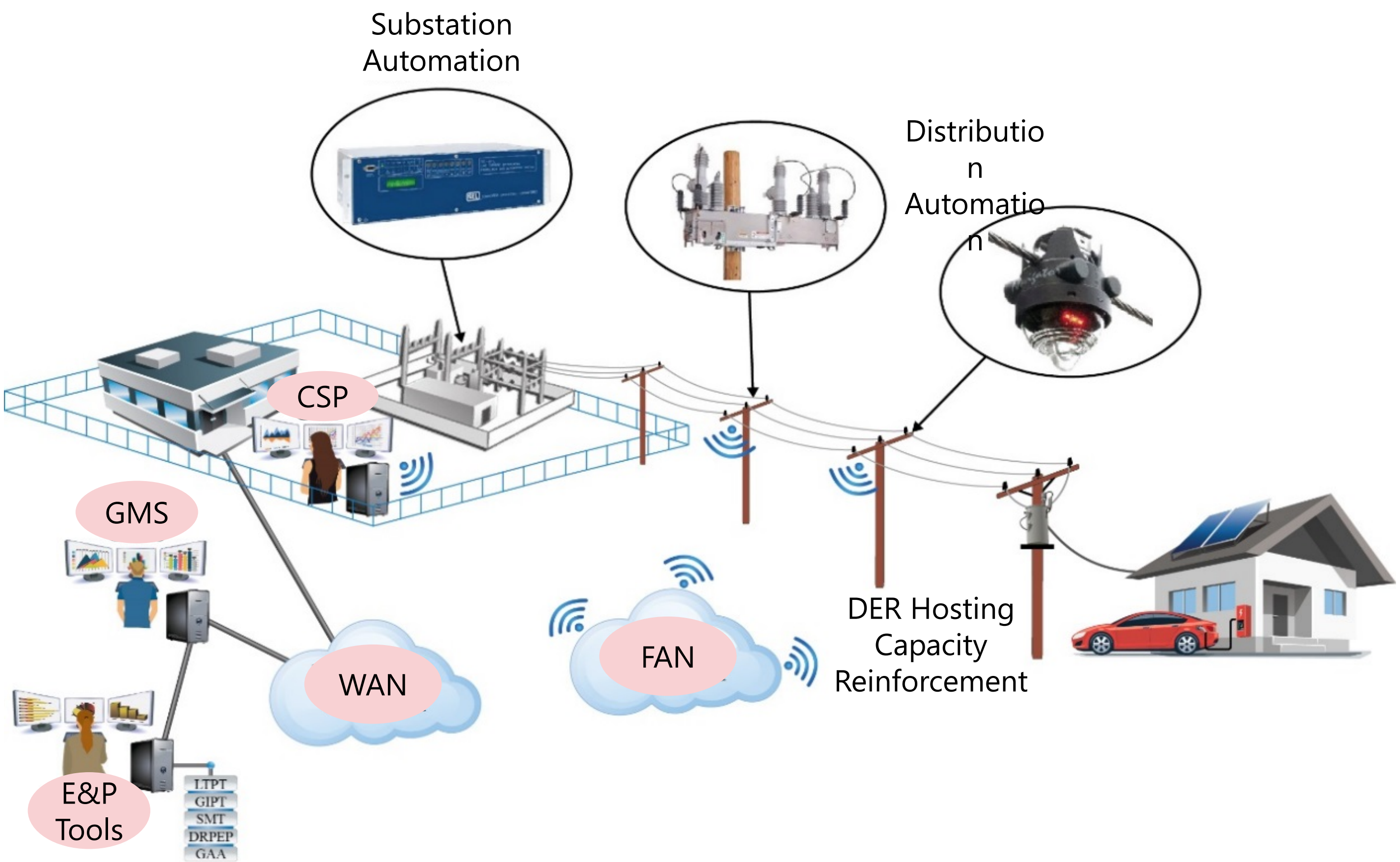
Strengthen and Modernize the Grid

Modernize Distribution Planning

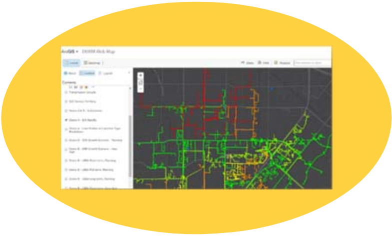
Influence Regulatory Outcomes that Benefit Customers



SCE's Grid Mod plan is an integrated technology suite to optimize DERs, improve safety, reliability and resiliency, and provide the foundation for a clean energy future



Realizing Grid Mod benefits requires investments in five technology capability categories



Engineering & Planning (E&P) Software Tools

Integrate DERs into grid planning processes

Grid Management System (GMS)

Enables grid operators to monitor grid conditions in real-time and control field devices remotely

Communications & Cybersecurity

Enables Grid Management System to communicate securely with DERs and other grid devices

Automation

Improves grid monitoring and control using real-time telemetry directional power flow data

DER Hosting Capacity Reinforcement

DERs that exceed thermal, protection, and power quality limits will require upgrades

The GMS integrates multiple systems designed to manage our increasingly dynamic grid

- The Advanced Distribution Management System (ADMS) will replace SCE's existing Distribution Management System (DMS) and Outage Management System (OMS) in order to reduce customer outage durations and automate high impedance fault detection
- The GMS will also include a DER Management System (DERMS), which will be used to communicate and interact with DER aggregators or other 3rd parties for system reliability and to optimize the use of DERs for grid services
- Advanced applications will be deployed to improve real-time situational awareness, power flow optimization and operational planning

GMS Roadmap

1. Distribution SCADA Upgrade → **2. Base ADMS Platform Implementation** → **3. Advanced ADMS and DERMS Capabilities**

8

SOUTHERN CALIFORNIA EDISON
Energy for What's Ahead℠

Distributed Energy Resource Management System

An IOU View

Introduction

- What is a DERMS supposed to do?
  - **Aggregate**: DERMS should take the services of many individual DER and present them as a smaller, more manageable, number of aggregated virtual resources for the appropriate location.
  - **Simplify**: DERMS should handle the granular details of DER settings and present simple grid-related services.
  - **Optimize**: DERMS should optimize the utilization of DER and existing infrastructure within various physical locations to get the desired outcome at minimal cost and maximum power quality.
  - **Translate**: Individual DER may speak different languages, depending on their type and scale. DERMS should handle these diverse languages, and present to the upstream calling entity in a cohesive way.

DERMS Considerations

- A DERMS is critical to ensure reliable coordination and availability of DER.
- Utilities need to invest in foundational grid capabilities to be able to manage the integration of DER as penetration levels of DER increase and the grid becomes more complex, to ensure reliability and to provide DER-based grid support services.
- Utilities need to develop critical DERMS functionalities first to enable DER to maximize their existing value streams without violating grid constraints.
- Capabilities are needed to orchestrate DER services across multiple third-party- controlled DER on the grid.
- Standards and certifications are not mature (e.g. cybersecurity, IEEE 1547, smart inverter functions etc.), so DERMS products will continue to evolve over time. Even if the standard itself appears to be mature, the implementation into products is still in the early phases.

DERMS Regulatory Drivers

Initiatives	Business Drivers	Controls Scope Deploy
Rule 21 Readiness - Smart Inverter Enablement	The Smart Inverter Working Group has completed milestones on phase 1, 2, and 3 of Smart Inverters.	Provide near real time visibility to behind the meter DER for Grid Operations. Also develop capabilities required to leverage Phase 3 SI control functionalities where needed based on identified use cases (e.g. resources participating in NWA projects).
AB2868 (Regulatory Mandate)	500MW for California IOUs of which 25% will be behind the meter Energy Storage resources IOUs need to manage the charging and discharging of Energy Storage resources to the benefit of the rate payer	IEEE2030.5 controls Virtual Power Plant functionality / Generation Management System (GMS) integration Integrate into Baseline and Settlement Systems Distribution OPF might be needed
SB 1339	Commercialization of Microgrids	Requires the development of standards and tariffs to support microgrid commercialization
Distribution Investment Framework	As part of future Local Capacity Analysis procurements for distribution capital deferral is going to include SI or non-SI based DERs that are part of a utility DR program or may be participating in the market through third party DR programs.	DERMS system interface with Demand Response Management Module Bottoms up Load Forecasting functions need to be enabled to support demand response functions.

Demonstrations

- Pacific Gas and Electric
- San Diego Gas and Electric
- Southern California Edison

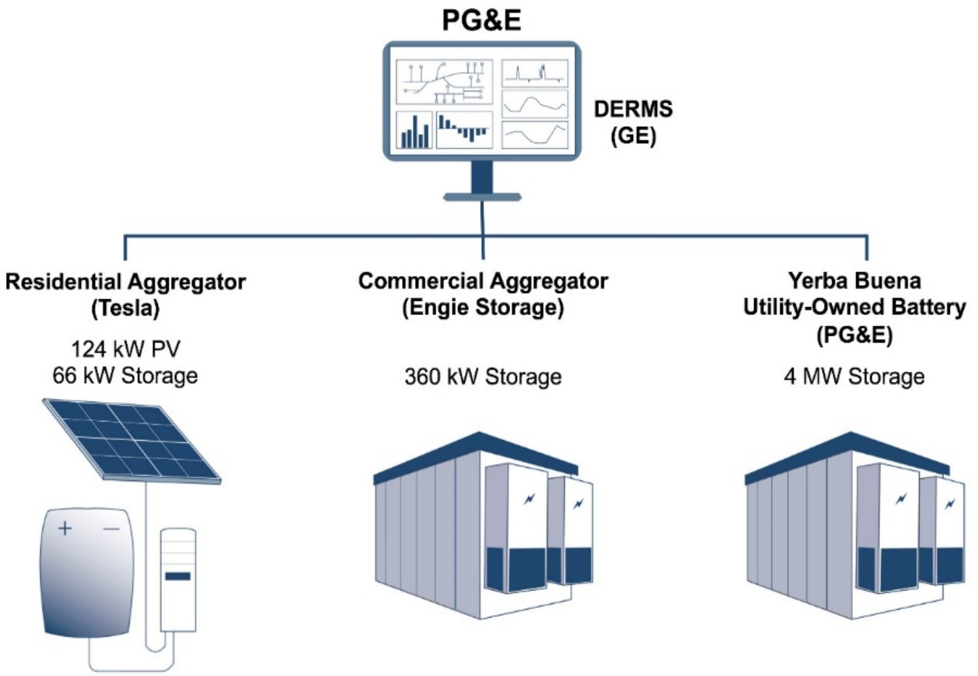
Consolidated List of DERMS Functions Demonstrated

- Foundational Grid Capabilities
- Critical DERMS Functions
- Manage DER Programs and Notifications
- Grid Reliability Services
- Decentralized Architecture
- Real Time Manual Operations
- Real Time Microgrid Optimization and Automatic Operation
- Optimal Power Flow
- Volt-Var Control

Pacific Gas and Electric's Project Goals

- Evaluating the technical ability of a DERMS to coordinate DERs (directly and through aggregators) for capacity and voltage support as distribution grid services
- Clarifying DERMS requirements and characterizing barriers to deployment at scale relative to today.

PG&E DERMS Demonstration



PG&E Key Lessons Learned

Pacific Gas and Electric Company

- A comprehensive DERMS technology is still not available off-the shelf. Foundational capabilities including data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS is key to address near term impacts of DER and providing the groundwork for future DERMS system
- A DER-aware ADMS paired with DERMS can identify and mitigate real-time and forecasted distribution capacity and voltage issues using a combination of DER constraints with real and active power dispatches.
- DER location, volume, availability, and dispatch assurance are critical for enabling DER based grid services.
- Large highly variable DERs participating in wholesale frequency regulation markets are difficult to forecast and incorporate into distribution calculations.
- Unification of standards, protocols, testing, and interoperability are needed as DERMS requirements and market structures get more defined.
- Multiple Use Application (MUA) requires transparency, coordination, and rules across programs to ensure proper prioritization and equitable settlement.
- To preserve distribution safety and reliability, distribution dispatches must have priority over wholesale market operations and visibility across both systems.

San Diego Gas and Electric's Project Goals

SDGE
A Sempra Energy utility

- DERMS should have the ability to remotely operate and dynamically manage individual and/or aggregated groups of DER.
- DERMS shall be able to serve as a microgrid controller

SDG&E DERMS Demonstration

- Borrego Spring Microgrid
  - Federated Hierarchical Controller
  - Microgrid Operations

Key Lessons Learned

- DERMS integration with ADMS is complex, but necessary for full visibility of the distribution system
- Provisioning new DER with DERMS to enable monitor and controls is time consuming and complex, largely due to lack of standards in DER/energy storage industry
- A decentralized solution (i.e. Borrego Springs Microgrid) depends on a robust communications system for remote operations
- Communication and control of third party DER and aggregations is challenging without the utility having full control to make decisions and system modifications during integration and commissioning the DER with DERMS

Southern California Edison Project Goals

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- Demonstrate the next generation grid infrastructure (field and backoffice) to manage, operate, and optimize the grid with high penetrations of DER
  - Provide a demonstration test bed for systems, equipment, and concepts for future modernization efforts
  - Verify technology readiness and potential architectures for production systems such as GMS and DERMS
  - Test new communications technologies and standards such as Field Area Network (FAN) and IEEE 2030.5 (communications to aggregators for smart inverters)
- Provide additional circuit and DER monitoring to the Distribution Management System to give grid operators a better view into the state of the circuit's operations
- Fund work to incorporate high-speed communications into the RIS control system and prove out adaptive protection concepts
- The project controls will be tested on the Titanium circuit out of Camden Substation in the southern part of the city of Santa Ana which has over 50% DER penetration

Energy for What's Ahead℠

SCE DERMS Demonstration

SOUTHERN CALIFORNIA EDISON
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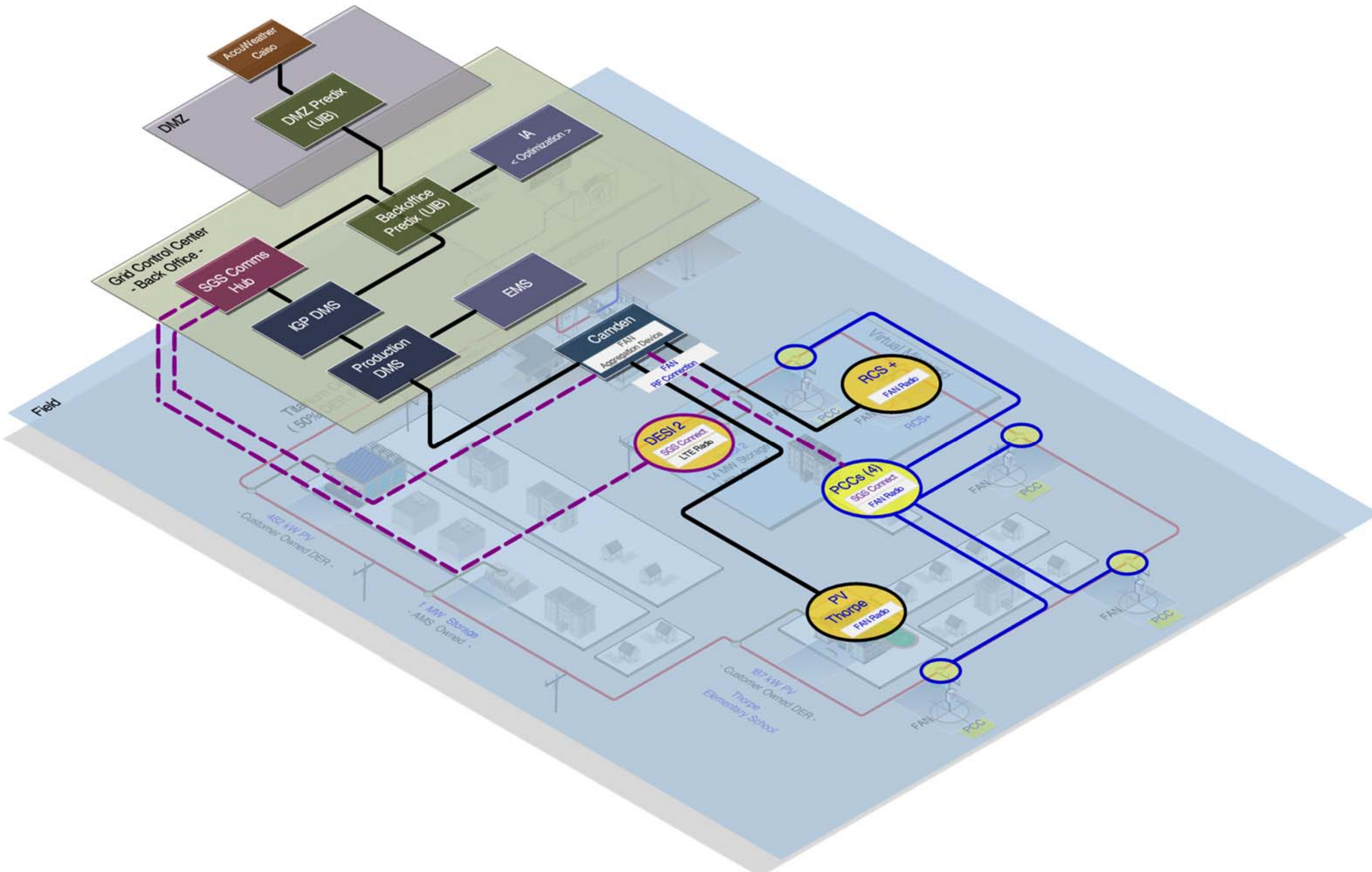

Energy for What's Ahead℠

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Key Lessons Learned

- Scalability of systems to handle a large number of DER is problematic.
- Data validation, exchange, and update between multiple systems are difficult and require engineering to ensure a stable system.
- Many DER systems deployed in the area with control systems are incapable of interacting with DERMS due to the installation of these systems prior to the establishing of communication requirements.
- Standardization and interoperability of DER communication protocols (2030.5 and 61850 for example) is still an issue immaturity of standard implementation.
- Cybersecurity requirements for DER control over the internet (2030.5) and patch management of DERs out in the field are still under development.

Grid Reliability Services

Capacity Service – carry additional load	Voltage Support – participate in Volt/Var Controls	Reliability – aid in power restoration efforts during outages	Constraint Management	Forecasting

Manage DER Programs and Notifications

DER Program Definitions	Program Translation into Grid Operations	Verification of DER Performance to Program Requirements

Foundational Grid Capabilities

Situational Awareness	Monitor Grid Status to ensure safety	Provide Microgrid control at point of interface

Core DERMS Functions

DER Registration, Aggregation and Grouping	DER Modeling/Short Term Forecast	DER Communication

Key Observations

- DERMS does not live in a vacuum and depends on other capabilities to realize value.
- A centralized utility distribution system management platform is needed to effectively orchestrate DER grid services across diverse group of DERs, customers and aggregators.
- No single system will reach all DERs on the grid.
- Cost competitiveness of DERMS and DER-based solutions should be fully evaluated through pilots and demonstrations prior to its deployment on a large scale.

Summary of DERMS expectations

- Provide a common application to manage all types and sizes of DERs across a utility's service territory, which includes the registration and maintenance of DER characteristics and capabilities.
- Provide constraint management of DERs to ensure continued grid reliability.
- Enable DER services to Distribution Operations to support reliability operations (e.g. peak load management, volt-VAr management).
- Facilitate Transmission-to-Distribution interface coordination and participation of DER devices in the CAISO market and Distribution Services market, as they develop.
- Enable economic optimization of the DER devices with respect to other DERs and conventional grid devices.
- Digest and/or create DER and load forecasts

Backup

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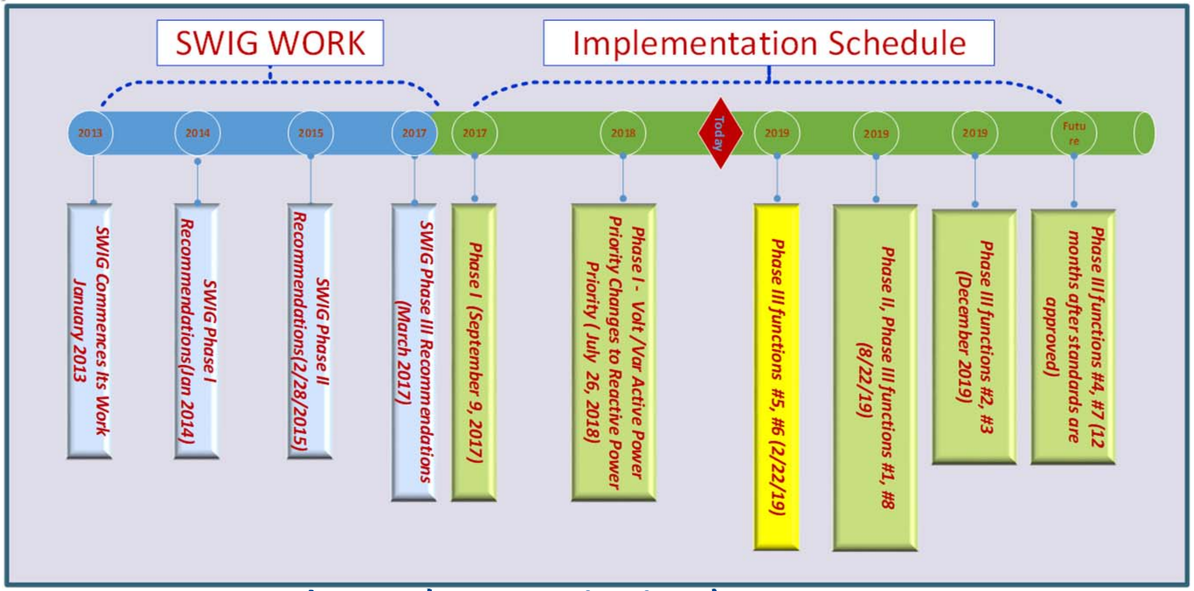
Energy for What's Ahead℠

California Smart Inverter Implementation Plan



Phase II (Communications)

- Establishes communication capabilities requirements between Generating Facilities and Utility
- February 22, 2019, new IR must meet one of three methods available to communicate to Smart Inverters
  - Direct to inverter
  - Through GF-EMS
  - Through Aggregator
- Default Protocol is the IEEE2030.5 Other may be used
- End Device (Inverter, GFEMS, Aggregator) must be certified under SunSpect Alliance Test

Phase I (Autonomous Functions)

Function 1: Low/High Voltage Ride-through
Function 2: Low/High Frequency Ride-through
Function 3: Dynamic Volt/Var
Function 4: Updated Fixed Power Factor Requirements
Function 5: Reconnect By Soft Start Requirements
Function 6: Ramp Control Requirements

Phase III (Advanced Functions)

Function 1: Monitor Key DER data
Function 2: DER Disconnect and Reconnect Commands
Function 3: Limit Maximum Active Power Mode
Function 4: Set Active Power Mode
Function 5: Frequency Watt Mode
Function 6: Volt Watt Mode
Function 7: Dynamic Reactive Support
Function 8: Scheduling Power Values and Modes

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 12

Responding Witness: Eileen L. Saunders

Q-12. Provide a breakdown by company of the total number of net metering applications for 2019, 2020, and 2021.

A-12. See table below for a breakdown by company of the total number of net metering applications for 2019, 2020, and 2021:

	Net Metering Service Applications		
	2019	2020	May 11, 2021 YTD
Kentucky Utilities Company	152	266	206
Louisville Gas and Electric Company	153	174	125

KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 13

Responding Witness: Eileen L. Saunders

Q-13. Provide the projected number of residential customers KU/LG&E anticipate disconnecting once disconnection is resumed.

A-13. It is difficult to predict the number of residential customers who will be eligible for disconnection once disconnection is resumed. It varies significantly depending on the number of customers who settle their account once disconnection notice has been given, establish payment plans, default on existing payment plans, government support programs, and other variables.

The numbers of LG&E and KU residential customers who would have been eligible for disconnection in the month of April were 22,152 and 20,951, respectively.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 14

Responding Witness: Legal Counsel

Q-14. Refer to KU/LG&E's response to Commission Staff's Fifth Request for Information, Item 2, regarding budgeted legal expenses. Provide a schedule showing the estimated cost per item listed in each category.

A-14. Objection. The requested information is attorney work product and is protected from disclosure. Kentucky common law and the Civil Rules afford special protection for information or materials prepared in anticipation of litigation when they reflect the "mental impressions, conclusions, opinions, or legal theories of an attorney or other representative of a party concerning the litigation." CR 26.02(3)(a); *Morrow v. Brown, Todd & Heyburn*, 957 S.W.2d 722 (Ky. 1997). Budgets for future legal expenses, when disaggregated on a case by case or matter by matter level, constitute exactly that type of information. "Forecasted litigation costs are, as a matter of definition, the expected costs of *anticipated* litigation and the forecasts can be said to have been, by their very nature, prepared in anticipation of litigation." *Securities and Exchange Comm'n v. R.J. Reynolds Tobacco Holdings, Inc.*, 2004 U.S. Dist. LEXIS 24545, at *23 (D.D.C. June 29, 2004). "Furthermore, when forecasted litigation costs are presented on a case-specific level, the mental impressions and judgments of the attorneys who made the cost estimates may, to a certain extent, become apparent if the forecasts are revealed." *Id.* Here, case-specific budgeted legal fees reflect the view of the Companies and their counsel as to the complexity of the issues involved, judgments about the merits of the claims and defenses asserted, and strategic considerations such as whether the Companies may consider settling a case early, as opposed to aggressively litigating the case to trial. Disclosure of forecasted matter-specific legal expenses can betray these mental impressions, opinions, and legal judgments. Accordingly, line item (disaggregated) legal expense forecasts are opinion work product and protected from disclosure. In the referenced data response, the Companies provided their legal expense budgets on an aggregate basis by category, which is far less likely to reveal mental impressions or strategy of counsel in a particular matter.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 15

Responding Witness: David S. Sinclair

Q-15. State how long each FLS customer interruption lasted for year 2020.

A-15. Each of the 2020 interruptions lasted ten minutes. (See KU AG-KIUC 1-185 for the date and time of each interruption.) KU's FLS tariff states, "Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month." It is the Company's practice to allow each electronically initiated interruption to time out at the prescribed ten-minute mark.

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Question No. 16

Responding Witness: Robert M. Conroy

Q-16. State whether customers with PV plus storage are eligible for service under the various TOD options. That is, explain whether these customers can elect not to take service under NMS but under one of the various TOD schedules or whether these customers can elect to take service under NMS and also under one of the various TOD schedules.

A-16. Yes, customers with PV plus storage are eligible for service under the Companies' various TOD standard rate schedule offerings that would be available to similarly situated customers who do not have PV plus storage (e.g., a residential customer with PV plus storage could take service under the Companies' RTOD rate offerings). Customers with PV plus storage taking service under TOD standard rate schedules may also take service under Rider NMS. What a customer with PV plus storage may not do is export energy from storage to the Companies' grid and receive NMS credit for it because energy storage does not meet the statutory definition of an eligible electric generating facility under KRS 278.465(2).

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Question No. 17

Responding Witness: John K. Wolfe

Q-17. Refer to the Direct Testimony of John K. Wolfe, Exhibit JKW-1, pages 17–18 of 37. Provide the 2020 information for customers experiencing multiple interruptions, and separately include momentary interruptions. Further, provide the 2019 data for customers experiencing multiple interruptions, including momentary interruptions.

A-17. Building on data provided in the Direct Testimony of John K. Wolfe, Exhibit JKW-1, the following table provides the number of LG&E and KU customers who experienced "n" outages during 2019 and 2020, where n = 1, 2, 3, 4, or 5+.

Customer Experiencing Multiple Interruptions		
	2019	2020
$CEMI_1$	246,021	201,053
$CEMI_2$	86,377	64,320
$CEMI_3$	33,339	17,431
$CEMI_4$	11,557	5,575
$CEMI_{5+}$	9,809	3,917

As shown, the number of customers experiencing multiple (>1) interruptions during 2020 reduced by 35.33% when compared to the Company's 2019 results.

Momentary interruptions are defined by IEEE 1366 as a brief (less than five minutes) loss of power caused by the opening and closing operation of an electric system's interrupting device(s). Momentary interruptions generally result from transient (temporary) faults which occur on the electric distribution system. Sources of transient faults include incidental animal, tree, or foreign object contacts and lightning strikes.

The LG&E and KU electric distribution system is comprised of various reclosing protection devices designed to prevent transient faults from contributing to long duration outages for customers. These reclosing devices have long been placed in transmission and distribution substations and at mid-points of overhead circuits.

Prior to advancement and convergence of reclosing device controls, communications, and data management technologies, the Companies could not report on the frequency of reclosing operations. Advancements in grid intelligence and communications capabilities on the transmission and distribution system are now enabling the Companies to monitor and report on SCADA connected reclosing devices which operate to clear transient faults. However, many legacy reclosing devices on the LG&E and KU system are not connected to SCADA or associated grid management systems, and thus, the Companies cannot accurately report all momentary reclosing operations which occur at a customer and device level. For this reason, LG&E and KU do not currently track momentary service interruptions at the customer level.

Momentary interruptions are tracked and reported at the device level only for those reclosing devices which are connected through SCADA to a grid management system. Routine momentary interruption reports at the device level are generated and monitored by assigned engineers to identify and act on opportunities to reduce momentary interruption frequencies. Looking forward, Advanced Metering Infrastructure should enable LG&E and KU to report on momentary interruptions at the customer level.

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Question No. 18

Responding Witness: William Steven Seelye

Q-18. Provide Exhibits 2, 3, and 4 from the Stipulation in Excel Spreadsheet format with all rows, columns, and formulas unprotected and fully accessible.

A-18. See attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

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Question No. 19

Responding Witness: William Steven Seelye

Q-19. Refer to the Application, the Direct Testimony of William Steven Seelye. Provide updates to Exhibits WSS-11, WSS-12, WSS-16, WSS-17, and WSS-19 based upon the Stipulation in Excel Spreadsheet format with all rows, columns, and formulas unprotected and fully accessible.

A-19. All charges agreed to by the parties to the Stipulation are shown in Stipulation Exhibit 5 (KU), Stipulation Exhibit 6 (LG&E electric), and Stipulation Exhibit 7 (LG&E gas). The Stipulation did not modify any of the miscellaneous and other service charges that were proposed by the Companies, as calculated in Exhibits WSS-11, WSS-12, WSS-16, WSS-17, and WSS-19 of the Direct Testimony of William Steven Seelye. The Excel spreadsheets used to develop those exhibits were filed with the Commission in the Companies' responses to PSC 1-56. Any modifications to those miscellaneous and other charges resulting in increases or decreases in miscellaneous or other revenue would necessitate a corresponding decrease or increase to base rate revenues (i.e., revenue from sales to ultimate consumers).

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Question No. 20

Responding Witness: Robert M. Conroy

Q-20. Refer to LG&E's response to Commission Staff's Sixth Request for Information, Item 33, regarding the revisions to the Firm Transportation Tariff.

a. Explain whether, and if so how, this revision could impact the eligibility for gas transportation service for a new customer's additional load if they install a generation facility that is served under Rate CGS, IGS, or DGGS.

b. Explain whether there are any circumstances in which a customer's generation load could qualify for gas transportation service without an underlying sales service.

A-20.

a. The proposed modification is not expected to impact the eligibility of a new or existing customer for gas transportation service. As proposed, Rate FT states that "Customers using gas to generate electricity other than as standby electric service, irrespective of the size of Customer's MDQ, are not eligible for service under this rate schedule unless such generation facilities were installed and operating under this Standard Rate FT before ninety (90) days after January 1, 2021.[4] Effective with that date, any Customer adding generation facilities, irrespective of the size and purpose of such generation facilities, will be required to take service for those facilities under Rate CGS, Rate IGS, or Rate DGGS, as applicable." Currently, LG&E's Rate FT already provides that customers using gas to generate electricity (except as standby generation) cannot be served under Rate FT.

A new customer seeking to qualify for service under Rate FT would be required to meet the requirements as set forth in Rate FT. Gas use by standby generation applications is not expected to impact the eligibility of a new (or existing customer) for service under Rate FT. Any gas loads (additional or existing) arising from the installation of a standby generation facility would

[4] In its response to Question No. 43 from the Commission Staff's Third Request for Information, dated February 5, 2021, LG&E indicated that the date of January 1, 2021, will be revised to the date that rates are approved in this proceeding.

be included or excluded from service under Rate FT depending on whether the generation facilities were installed before or after the effective date. If excluded, the gas loads would be physically separated to allow for separate metering and billing under the applicable tariff.

b. After the proposed date, all new gas-fired generation loads (standby or otherwise) whether for new or existing customers would be required to be served under Rate CGS, IGS, or DGGS, depending on the applicability of those rate schedules to the load being served. The proposed change ensures appropriately sized meters are installed to meet the loads served through those meters. As outlined in LG&E's response to Question No. 108 from Commission Staff's Second Data request dated January 8, 2021, appropriately sized meters designed to meet the loads served through those meters improves meter accuracy and helps prevent subsidies among customers and customer classes.

   Additionally, gas-fired generation customers (standby or otherwise) are appropriately served under Rates CGS, IGS or DGGS. Rider TS-2 gas transportation service is applicable to each of those rate schedules if the customer meets the requirements set forth in Rider TS-2. Gas loads for standby gas-fired electric generation are permitted under Rates CGS and IGS to the extent that they have a connected load less than 2,000 cubic feet per hour. Generation gas loads (standby or otherwise) in excess of this threshold are served under Rate DGGS. Unlike Rate FT, sales Rate Schedules CGS, IGS, and DGGS have fundamentally different service characteristics (such as firm balancing) that are more suitable for generation applications than the "as-available" balancing and other services embodied in Rate FT.

   A generator that might otherwise be large enough to qualify for Rate FT would have a connected load of 2,000 cubic feet or more per hour. LG&E's tariff already provides that generation facilities of this size are to be served under Rate DGGS. Rate DGGS helps maintain and support the reliability of LG&E's gas system for all gas customers. It also helps prevent cost subsidies among gas customers. In larger generating applications, Rate DGGS allows customers generating electricity to be clearly identified and their potential maximum gas usage quantified. This identification ensures that adequate metering and pipeline infrastructure are in place to serve these kinds of gas customers.

   Similarly, Rates CGS, IGS, and DGGS help ensure that gas will be available to meet the hourly and daily variations in the customer's demand for gas used to generate electricity. Gas transportation services require gas supplies to be nominated a day in advance -- which will not likely align with the customer's need for electricity because generation customers may start or stop the to use gas at any time (and without notice). This means that gas for the customer may continue to be delivered to LG&E when there is no demand (for example, arising from a forced outage of the generator). Conversely, the customer's need for generation may precede its ability to schedule gas. These kinds of unforeseen imbalances are potentially detrimental to the overall reliable operation of LG&E's gas system. Unlike transportation-only service under Rate FT, Rate DGGS ensures that gas supply and balancing services are available on a firm basis.

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Question No. 21

Responding Witness: Eileen L. Saunders / William Steven Seelye

Q-21. Refer to KU/LG&E's responses to the Joint Intervenor's Second Request for Information, Item 2c, page 6 of 6, Average Cost Per Late Payer table. For both KU and LG&E, provide the calculation, in Excel spreadsheet format with all rows, columns, and formulas unprotected and fully accessible, showing how the amount in the customer contact row was calculated. Provide as much detail and explanation as possible and show the calculation for how each component was derived.

A-21. See attachment being provided in Excel format. The average cost was calculated on a combined basis for KU and LG&E.

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

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Question No. 22

Responding Witness: William Steven Seelye

Q-22. Refer to LG&E's response to Commission Staff's Third Request for Information, Item 45, which provided a revised cost justification for the gas meter test fee in the amount of $112.86. Also refer to Stipulation Exhibit 7, page 53 of 144, proposed settlement tariff, which reflects the originally proposed gas meter test fee amount of $101. Confirm which amount LG&E is currently proposing for the gas meter test fee.

A-22. The correct amount is $112.86. The response to PSC 3-45, provided a revised calculation reflecting the correct charge. This revised charge was inadvertently not updated when preparing the Stipulation Exhibit 7. Because there was no revenue during the test year for this charge, the correction does not impact the revenue increases stipulated by the parties.

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Question No. 23

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-23. Refer to the Application, Direct Testimony of Robert M. Conroy, page 47, lines 7–10, which discusses the proposed revision to the Economic Development Rider (EDR) requiring a customer seeking an EDR contract designed to retain the load of existing customers to provide an affidavit stating that, without the rate discount, its operations would cease or be severely restricted and demonstrating financial hardship to the Company. Provide a copy of the affidavit that customers would be required to sign, and the Companies file, in relation to a request for a retention EDR contract

A-23. See attached.

SPECIAL CONTRACT
ECONOMIC DEVELOPMENT RIDER – LOAD RETENTION AFFIDAVIT

I, ________________________________ (affiant's name), testify and affirm that I am ____________________________ (affiant's position with Customer) for Customer, __________________________________ (Customer's name), that the representations made in this affidavit are based on my personal knowledge, and that I am authorized to represent the following on Customer's behalf:

Customer currently takes service from Kentucky Utilities Company or Louisville Gas and Electric Company (circle one) ("Company") under account number ______________________ in accordance with the rate provisions of rate schedule _________________________. I hereby testify and affirm that without the rate discount for which Customer is contracting with Company under the EDR Contract entered into between Company and Customer on ____________ ____, 20___, Customer's operations served by Company would cease or be severely restricted as follows:

____

____

____

_______________________________________ _________________________

AFFIANT'S SIGNATURE DATE

COMMONWEALTH OF KENTUCKY)
) SS
COUNTY OF __________________)

This document was acknowledged before me on ________________ ___, 20___, by ____, as AFFIANT.

____

(SEAL) **NOTARY PUBLIC, STATE AT LARGE**

My commission expires:________________________

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Question No. 24

Responding Witness: Eileen L. Saunders / William Steven Seelye

Q-24. For both LG&E and KU, provide separate cost justification, in Excel spreadsheet format with all rows, columns, and formulas unprotected and fully accessible, for a regular hours disconnect/reconnect service charge and an after-hours disconnect/reconnect service charge. Provide as much detail and explanation as possible, and show the calculation for how each component was derived.

A-24. The Companies do not track costs separately for disconnects/reconnects performed during regular hours versus after hours. Further, the Companies do not separately track the number of disconnects/reconnects performed during regular hours versus after hours. Because there is currently no charge differential for regular hours and after hours disconnects/reconnects, the Companies have no business reason to track these costs or billing units for the periods. The Companies provided full cost support for their proposed disconnect/reconnect charges in Seelye Direct Testimony Exhibits WSS-19 and WSS-20, as well as in response to KU PSC 2-124, KU PSC 3-9, KU PSC 3-22, LG&E PSC 2-136, LG&E PSC 3-9, and LG&E PSC 3-22.

Depending on the availability of service technicians, the Companies will normally schedule reconnects until 9:00 PM on weekdays to allow service to be reconnected for customers who make payments on their bills as late as 7:00 PM during weekdays. This practice allows customers who have been disconnected for non-payment to be reconnected as soon as possible, thus often avoiding the possibility of the customer going through a night, or an additional night, without electric or gas service. The Companies believe that this is a reasonable and appropriate practice for customers who have been disconnected for non-payment.

Additionally, setting up systems and requiring employees or contractors to track regular hours and after hours disconnects/reconnects will add to the cost of performing these services.

It is the Companies' recommendation that the Commission accept the Companies' proposed disconnect/reconnect charge without incorporating a cost differential between disconnects/reconnects performed during "regular hours" versus "after hours".

Attached is a spreadsheet providing a *general estimate* of the cost of performing disconnects/reconnects during regular hours versus the cost of performing disconnects/reconnects during after hours. For KU, the estimated cost of a disconnect/reconnect is $35.06 during regular hours and $109.83 during after hours. For LG&E, the estimated cost of a disconnect/reconnect is $32.22 during regular hours and $69.49 during after hours. The reason for the larger cost differential between regular hours and after hours disconnects/reconnects for KU is that, unlike LG&E, KU does not normally maintain an after hours shift and must rely on employees working overtime to provide these services. But as mentioned above, the Companies do not track these cost differentials.

Moreover, these estimated regular-hours versus after-hours disconnect/reconnect costs show the reasonableness of the proposed $37.00 disconnect/reconnect charge for KU and $32.00 for LG&E; having two different charges would result in significantly higher after-hours charges with little or no change from the proposed charges for regular-hours disconnections and reconnections. In other words, few customers (if any) would benefit from bifurcating the charges, whereas the few customers who sought to have after-hours disconnections or reconnections would pay significantly higher charges. Therefore, it does not appear to be appropriate or necessary to bifurcate the proposed charges, which are well supported, as noted above.[5]

[5] *See* Seelye Direct Testimony Exhibits WSS-19 and WSS-20, as well as in response to KU PSC 2-124, KU PSC 3-9, KU PSC 3-22, LG&E PSC 2-136, LG&E PSC 3-9, and LG&E PSC 3-22.

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

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Question No. 25

Responding Witness: William Steven Seelye

Q-25. Provide the billing analysis included in the Stipulation as Exhibits 2, 3, and 4 in Excel spreadsheet format with all rows, columns, and formulas unprotected and fully accessible.

A-25. See the response to Question No. 18.

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Question No. 26

Responding Witness: William Steven Seelye

Q-26. State how cost was classified for the energy component used in KU/LG&E's embedded class cost of service studies from 2012 to the current rate case for both KU and LG&E

A-26. Cost was consistently classified for the energy component using the FERC Predominance Methodology in each embedded cost of service study performed from 2012 to the current rate case. There has been no change in the methodology. For a discussion of the FERC Predominance Methodology, see Rebuttal Testimony of William Steven Seelye, at pages 88-93.

From the 2012 to the current embedded cost of service study, fuel expenses and variable operation and maintenance expenses have decreased or remained flat, relative to other costs which have increased. The following tables show energy costs and the percentage of energy costs to total costs for each study.

Kentucky Utilities
Analysis of Residential Energy Costs from the Class Cost of Service Study

	2012 Rate Case	2014 Rate Case	2016 Rate Case	2018 Rate Case	2020 Rate Case
Cost	$ 191,749,968.49	$ 214,583,905.46	$ 213,761,432.32	$ 192,902,958.04	$ 190,200,218.74
Billing Units (kWh)	5,944,171,807	6,197,488,349	6,091,971,051	5,965,245,032	5,943,619,831
$/kWh	$0.03226	$0.03462	$0.03509	$0.03234	$0.03200
Ratio of Energy-Related Cost to Total	39.03%	37.53%	36.10%	32.20%	27.98%

Louisville Gas and Electric Company Analysis of Residential Energy Costs from the Class Cost of Service Study					
	2012 Rate Case	2014 Rate Case	2016 Rate Case	2018 Rate Case	2020 Rate Case
Cost	$ 168,377,229.18	$ 170,993,820.28	$ 153,649,090.07	$ 130,743,999.55	$ 131,381,848.19
Billing Units (kWh)	4,216,187,376	4,267,045,465	4,180,088,831	4,077,649,481	4,049,109,440
$/kWh	$0.03994	$0.04007	$0.03676	$0.03206	$0.03245
Ratio of Energy-Related Cost to Total	45.90%	43.37%	36.50%	32.20%	27.08%

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Question No. 27

Responding Witness: William Steven Seelye

Q-27. Confirm whether the effective load carrying capability has been implemented in PJM or approved by FERC for use in PJM, and if so, state when it was implemented or approved.

A-27. It should be noted than neither LG&E nor KU is a member of PJM. After the hearing in these proceedings, the Federal Energy Regulatory Commission ("FERC") issued an order on April 30th in Docket ER21-278 rejecting PJM's proposed changes to its tariff, which would have implemented ELCC in 2021. Representatives of PJM have indicated to Mr. Seelye that considering FERC's order, PJM is not sure when ELCC will be implemented.

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Question No. 28

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-28. If a married couple taking service under Tariff NMS-1 or NMS-2, with the bill in one person's name, divorces or one person passes and the other spouse stays in the house and the name on the bill changes, explain whether this would be considered a termination of service, resulting in a termination of bill credits, or if this would this be considered something less than a termination of service.

A-28. If both persons were listed on the account as financially responsible at the time of divorce or death, the bill credits under NMS would transfer to the then determined primary account holder.

If a person was the survivor or recipient of the residence in a divorce and was not listed on the account or not listed as financially responsible to the account, the old account would be closed and a new one created. In this scenario, the accumulated credits under NMS would not transfer.

Any accumulated credits would not be transferable or eligible for a cash refund on the closing of an account.

This process is not unique to NMS. The Companies utilize the same process when transferring, closing, or creating a new account.

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Question No. 29

Responding Witness: Kent W. Blake

Q-29. Explain why KU/LG&E have not provided the salary information for the identified executives whose salary is $50,000 or more in its annual report filed with the Commission.

A-29. The referenced schedule in the Companies' annual report filed with the Commission is an extract of the same schedule filed as part of each Company's FERC Form 1. Since 2016, the Companies adopted a practice followed by other utilities and left the salary information blank with the footnote "Salary information for all officers is on file in the office of the respondent." In its 2020 annual report filed with the Commission, the Companies inadvertently failed to include the footnote from its FERC Form 1. More importantly, this information and more has been provided in this case as well as all rate cases filed by the Companies such that the officer salary information recovered in rates is fully disclosed to the Commission and the parties who desire to review it. For the current proceedings, the salary and other compensation information is filed for the base period of March 1, 2020 through February 28, 2021 and the forecast period, June 1, 2021 through June 30, 2022 at tab 60 of each application. The information for the base period was updated for actual information with the base period update filed April 14, 2021. A detailed schedule of the salary and benefits for each officer for the base period and the last three calendar years, 2019 – 2017, is also filed with KU and LG&E's responses to KPSC Staff Data Request No. 1-41.

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Question No. 30

Responding Witness: Eileen L. Saunders

Q-30. Provide the monetary benefit to the system, if any, by the rates that will be paid for the fast charging service and facilities expected to be installed by KU/LG&E in 2022.

A-30. The Companies do not expect the rates paid for its fast charging service to provide direct monetary benefit to the entire system. Fast charging stations are a key enabling technology necessary for customers to adopt electric vehicle technology. The Companies are not proposing to install fast charging stations to create revenue opportunities from the stations themselves or to compete with other providers of fast charging services. The purpose is to provide greater customer access to fast charging stations so that customers can adopt electric vehicles. See Mr. Seelye's direct testimony pages 74-75.

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Question No. 31

Responding Witness: Eileen L. Saunders

Q-31. Explain whether customers will be better off, worse off, or indifferent from electric vehicle (EV) fast charging stations owned by KU/LG&E or by third-party owned EV fast charging stations would be minimized or non-existent.

A-31. Customers of the fast charging stations currently proposed to be installed by KU and LG&E, as described in Ms. Saunders' direct testimony, will be indifferent to whether those stations are owned by KU/LG&E or by third parties. The Companies intend to locate the fast charging stations in areas unserved or underserved today by third party providers. The Companies intend to charge rates competitive with, but not significantly below, the market rate for fast charging service. Because of this intentional avoidance of location and price competition, customers will be indifferent to the owner of the station.

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Question No. 32

Responding Witness: Eileen L. Saunders

Q-32. Explain whether the Companies intend to or have done any studies to identify areas on its system in which the actual incremental system costs of adding demand specific to EV fast charging station makes sense.

A-32. The Companies have completed an initial evaluation focused on whether there is sufficient system capacity within a reasonable proximity of the interstate highways. Approximately 12 general areas are under consideration for a Company-owned EV fast charging site. The Companies plan to select sites with minimal system upgrade costs. Additional analysis will continue into the fall. The Companies also assist their customers in identifying areas on their system in which the incremental costs of adding demand specific to EV fast charging stations (or other loads) are minimized.

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Question No. 33

Responding Witness: Lonnie E. Bellar

Q-33. Provide a copy of the 2021 Agreement between LG&E and the Louisville Air Pollution Control Board in regard to limiting the operation of the Mill Creek Station in order to address the Louisville/Jefferson County ozone requirements for the 2021 ozone season or subsequent ozone seasons.

A-33. See attached. The Louisville Air Pollution Control Board will consider this agreement at their next meeting which is scheduled for May 19, 2021. A fully executed copy will be filed when available.

ENFORCEABLE BOARD AGREEMENT

This Enforceable Board Agreement is entered into by and among Louisville Gas and Electric Company (LG&E), the Louisville Metro Air Pollution Control Board (Board), and the Louisville Metro Air Pollution Control District (District).

WHEREAS, the U.S. Environmental Protection Agency (EPA) on April 30, 2018, designated the Louisville Metropolitan Statistical Area (MSA), consisting of Jefferson, Bullitt, and Oldham Counties in Kentucky and Clark and Floyd Counties in Indiana, as non-attainment for the 2015 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 70 ppb; and

WHEREAS, District Regulation 3.01 Section 4 prohibits the emission of an air contaminant that would violate or interfere with the attainment or maintenance of, an ambient air quality standard; and

WHEREAS, ground level ozone is not emitted directly into the air, but is created by chemical reactions between oxides of nitrogen (NOx) and volatile organic compounds (VOC); and

WHEREAS, LG&E owns and operates the Mill Creek Electric Generating Station (Mill Creek), a coal-fired power plant, located at 14660 Dixie Hwy, Louisville, KY 40272, which emitted approximately 7,958 tons of NOx in 2018, and 6,920 tons of NOx in 2019, and is the largest single source of NOx emissions in the MSA; and

WHEREAS, the District has not determined which sources violate or interfere with the attainment or maintenance of an ambient air quality standard under District Regulation 3.01, but LG&E has agreed to take measures to reduce its emissions of NOx at Mill Creek consistent with the objectives of District Regulation 3.01;

NOW, THEREFORE, this Agreement reflects the commitment of LG&E and the approval of the Board and the District, to implement the following:

1. **Project Description**

From May 9, 2021, to October 31, 2021, the sum of Mill Creek Units 1, 2, 3 and 4 NOx emissions shall be equal to or less than 15 tons per calendar day. Compliance with the daily limit shall be determined through review of data generated by the plant's Continuous Emissions Monitoring System in accordance with 40 CFR Part 75.

This daily limit shall not apply to the following events in 1.A or 1.B:

A. To hours when Mill Creek Units 3 or 4 have experienced an outage, unit derate including operation of unit below minimum operating load for SCR operation, startup/shutdown, or SCR outage or derate at any time during the hour.

B. To hours when forecasted high demand due to extreme weather or system demand concurrent with other unit outages in the LG&E-KU system require, in the reasonable judgment of LG&E, Mill Creek Units 1 or 2 to operate at any time during the hour to ensure system reliability in accordance with North American Electric Reliability Corporation (NERC) requirements.

C. Nothing in this agreement shall obligate LG&E to purchase wholesale power from third-party power generation sources in response to the above events, but LG&E may undertake such purchases based on LG&E's determination of prudent utility practice.

For any calendar day when plant-wide emissions of NOx exceed 15 tons, including the hours specified in paragraph 1.A or 1.B, LG&E shall inform the District in writing within 24 hours, or the next business day if the due date falls on a weekend or holiday.

The written notification to the District shall include: (1) the reason for the event; (2) the anticipated duration; (3) all actions taken to prevent or minimize the delay or prevention of performance; (4) an explanation of why the delay or prevention of performance was necessary; and (5) the steps LG&E shall take to ensure that the performance of its obligations under this Agreement will be reinstituted as early as practicable after cessation of the event causing the delay.

2. **Verification and Reporting**

Within 30 days after the end of the calendar month, LG&E shall submit a monthly report to the District identifying daily plant-wide emissions of NOx. The reports shall be certified by a responsible official, as defined in Regulation 2.16 Title V Operating Permits, Section 1.35, at the facility. This certification shall include the statement, "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in this document are true, accurate and complete." The District reserves its right to inspect the facility as provided in applicable law to verify compliance with LG&E's commitment set forth in Paragraph 1. All reporting and verification requirements under this agreement shall terminate upon submittal of the monthly report for October 2021.

3. **Effect on Permits**

Nothing in this Agreement affects, limits or waives any permitting requirement to which LG&E is subject. If any of the measures that LG&E has undertaken or will undertake in accordance with this Agreement are subject to any permit requirement under federal or state law or District regulations, such measures shall remain subject to such permitting requirements.

4. **Legal Effect of the Agreement**

LG&E agrees to fully implement the projects set forth in Paragraph 1 above. Nothing in this Agreement shall constitute evidence of any admission of liability, law or fact, a waiver of any right or defense, or estoppel against the parties to this Agreement.

5. **Reservation of Rights and Legal Remedies**

Nothing in this Agreement affects, limits or waives the District's legal rights, remedies or causes of action based on statutes, regulations or permit conditions within the jurisdiction of the District, and LG&E reserves its rights and defenses thereto. The District expressly reserves its right to seek enforcement of this Agreement or to take further action through administrative orders or other means at any time and to take any other action it deems necessary, including the right to order all necessary remedial measures and assess penalties for proven violations of applicable laws or regulations, and LG&E reserves its defenses thereto.

Nothing in this Agreement affects, limits or waives LG&E's legal rights, including LG&E's right to administrative or judicial review of any action by the District.

6. **Amendments or Modifications**

No modification or amendment to the terms or conditions of this Agreement shall be effective until reduced to writing and executed by LG&E and the Board.

Louisville Metro Air Pollution Control Board

By: ________ ______________
Carl E. Hilton
Chairman

Date: ______________________

Louisville Gas and Electric Company

By: Lonnie E. Bellar
Lonnie E. Bellar
Chief Operating Officer

Date: 5/7/21

Louisville Metro Air Pollution Control District

By: ______________________
Rachael Hamilton
Interim Executive Director

Date: ______________________

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 34

Responding Witness: Eileen L. Saunders

Q-34 Explain how the Companies will determine the cause for the hesitancy of customers to request service under Rate OSL before the Companies' next general rate case.

A-34. The Companies do not believe we have experienced hesitancy from customers requesting service under Rate OSL. The OSL rate is one of many rate options including general service and power service available to customers.

Rate OSL may not be the best possible option for every eligible customer. The customer's decision is dependent on multiple variables such as whether the facility includes the ball fields, how the facility is used, the size of the ball fields, the number of volunteers, and the level of physical access required to turn on the lighting. The Companies encourage customers to join a rate schedule that aligns with their best interest and circumstances.

Some customers have delayed the start of sports games to avoid demand charges. Several of these sports complexes work with volunteers, who may be unfamiliar with the nuances of demand charges, unknowingly resulting in them being subjected to a demand charge.

We meet and listen to our customers' needs. As a result of customer feedback, the Companies are proposing through this rate case a tariff change to reduce the summer peak between May through September by one hour. This change will allow ball fields to start their games earlier.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 35

Responding Witness: Eileen L. Saunders

Q-35. Explain what the Companies are currently doing to encourage eligible customers to take service under Rate OSL.

A-35. Business Service Center Specialists, working with new or existing qualifying outdoor sports lighting facilities, present the OSL rate as an optional rate. The Specialists explain the OSL rate in detail for comparison to other qualifying rates and customers choose the rate that best fits their usage patterns.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 36

Responding Witness: Eileen L. Saunders

Q-36. For each Company, provide the number of applications for net metering service that have been filed up to present that are not in service and have not been withdrawn.

A-36. See table below for the count of applications for net metering service that have been filed from October 1, 2016 through May 11, 2021 that are not in service and have not been withdrawn. Of those applications, KU and LG&E applications open over 1 year old are 16% (24) and 14% (16), respectively.

	Net Metering Service Applications
Kentucky Utilities Company	152
Louisville Gas and Electric Company	112

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 37

Responding Witness: Eileen L. Saunders

Q-37. For each Company, provide the number of applications for net metering service that were filed with the Companies after the applications were filed in these matters, but have subsequently been withdrawn. If available, provide the reason for each withdrawn application.

A-37. There have been a total of 4 approved net metering applications (1 for KU and 3 for LG&E) which were withdrawn since the applications were filed in these matters. All were due to the customer cancelling the installation.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 38

Responding Witness: Lonnie E. Bellar

Q-38. In relation to the change in the planned economic life of Mill Creek 2 and the identified and planned upgrades to satisfy projected environmental requirements for Mill Creek 2, explain when stay open costs were identified, which plan those costs were based on, and when those costs were determined with any certainty. Further, provide updates or changes to those explanations that have been made since July 2020.

A-38. Stay open costs, as used in both the Companies' ECR filing for construction of ELG water treatment facilities at Mill Creek (Exhibit SAW-1) and in this filing (Exhibit LEB-2), include ongoing capital and fixed O&M (including labor) that would be avoided if the unit were retired.

With the exception of fixed fuel transportation costs, all stay open costs for both analyses were developed based on the 2020 Plan. The 2020 Plan assumed Mill Creek 2 would operate through 2034. The 2020 Plan forecast was completed in the fall of 2019. As a result, the stay open costs and assumptions for Mill Creek 2 as used in Exhibit LEB-2 are nearly identical to those used for that unit in the ECR filing.[6]

Table 6 in Exhibit LEB-2 lists the revenue requirement differences from retiring Mill Creek 2 in 2028 versus 2034. The "stay open costs" in Table 6 include the stay open costs from Table 8 and the cost of ELG consumables attributable to Mill Creek 2.

The assumptions used to calculate stay open costs and ELG consumables for both the ECR case and the Analysis of Generating Unit Retirement Years in these cases, and thus these costs in either analysis, have not changed materially since those analyses were completed. The capital cost of ELG compliance, however, has decreased substantially for the Mill Creek station and the portion attributable to Mill Creek 2 is now approximately $5 million.

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[6] In Table 8 of Exhibit LEB-2, major maintenance and other stay open costs are listed separately. In Table 4 of Exhibit SAW-1, these costs are combined. The minor differences between total stay-open costs in these tables are explained by differences in fixed fuel transportation costs between the 2020 and 2021 Plans.

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 39

Responding Witness: Robert M. Conroy / Counsel

Q-39. Explain whether KU/LG&E agree that net metering applications filed prior to the effective date of the proposed net metering tariffs in these matters are eligible for service under NMS-1.

A-39. No, the Companies do not agree that customers who have only applied for net metering service but do not have an eligible electric generating facility prior to the effective date of the proposed net metering tariffs in these proceedings may take service under Rider NMS-1. The Companies do not believe there is any uncertainty in the applicable statutory text concerning this issue. Since the General Assembly amended KRS 278.466 effective January 1, 2020, the ***mandatory*** default rule for how net metering customers are to be compensated for energy that flows to a retail electric supplier is set forth in KRS 278.466(3) and (4) (emphases added):

> (3) A retail electric supplier serving an eligible customer-generator ***shall*** compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier, as measured by the standard kilowatt-hour metering prescribed in subsection (2) of this section. The rate to be used for such compensation ***shall*** be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative on behalf of one (1) or more retail electric suppliers.
>
> (4) Each billing period, compensation provided to an eligible customer-generator ***shall*** be in the form of a dollar-denominated bill credit. If an eligible customer-generator's bill credit exceeds the amount to be billed to the customer in a billing period, the amount of the credit in excess of the customer's bill ***shall*** carry forward to the customer's next bill. Excess bill credits ***shall*** not be transferable between customers or premises. If an eligible

> customer-generator closes his or her account, no cash refund for accumulated credits ***shall*** be paid.

The limited and exclusive exception to the new mandatory dollar-denominated credit approach for net metering compensation is set out in KRS 278.466(6) (emphases and bracketed numeration added):

> For an [i] *eligible electric generating facility* [ii] *in service* prior to the effective date of the initial net metering order by the commission in accordance with subsection (3) of this section, the net metering tariff provisions in place when the [iii] *eligible customer-generator* [iv] *began taking net metering service*, including the one-to-one (1:1) kilowatt-hour denominated energy credit provided for electricity fed into the grid, [v] *shall remain in effect at those premises* for a twenty-five (25) year period, regardless of whether the premises are sold or conveyed during that twenty-five (25) year period.

Though there was some discussion at hearing about whether there is any ambiguity in KRS 278.466(6), a plain reading of the express terms of the statute shows no vagueness:

i. **Eligible electric generating facility.** Legacy rights attach only to an eligible electric generating facility, which KRS 278.465(2) defines to be "an electric generating facility that: (a) Is connected in parallel with the electric distribution system; (b) Generates electricity …; and (c) Has a rated capacity of not greater than forty-five (45) kilowatts[.]" Notably, this definition is exclusively in the present tense, i.e., it describes actually existing conditions, and KRS 278.466(6) refers to "an eligible electric generating facility," not a prospective or potential eligible electric generating facility.

ii. **In service.** KRS 278.466(6) refers to an eligible electric generating facility that is in service. As noted at hearing, the Companies are unaware of any industry or legal definition of "in service" as that would include a generating facility that does not yet exist. For example, the Federal Energy Regulatory Commission's Uniform System of Accounts defines balance sheet account 101, "Electric plant in service (Major only)," to include "the original cost of electric plant … owned and used by the utility in its electric utility operations, and having an expectation of life in service of more than one year from date of installation …."[7]

[7] 18 CFR 101 (as of May 7, 2021), available at: https://www.ecfr.gov/cgi-bin/text-idx?SID=500086551193d0b95564044ae753bd3f&mc=true&node=pt18.1.101&rgn=div5.

iii. **Eligible customer-generator.** Again, this is a statutorily defined term, which KRS 278.465(1) defines to be "a customer of a retail electric supplier who owns and operates an electric generating facility that is located on the customer's premises, for the primary purpose of supplying all or part of the customer's own electricity requirements[.]" This definition too is exclusively in the present tense, and KRS 278.466(6) refers to an "eligible customer-generator," not a prospective or potential eligible customer-generator.

iv. **Began taking net metering service.** Under the Companies' current net metering tariff provisions, a prospective eligible customer-generator can begin taking net metering service only if the customer:

a. "owns and operates a generating facility located on Customer's premises that generates electricity using solar, wind, biomass or biogas, or hydro energy in parallel with Company's electric distribution system to provide all or part of Customer's electrical requirements," ***and***

b. "executes Company's written Application for Interconnection and Net Metering."

Therefore, a customer who merely applies to take net metering service but does not meet the statutory definition of an eligible customer-generator (which is what the Companies' tariff provisions spell out) cannot begin taking net metering service, and therefore cannot be an eligible customer-generator who receives legacy net metering service under KRS 278.466(6).

v. **Shall remain in effect at those premises.** As explained above, a prospective eligible customer-generator cannot *begin* taking net metering service until meeting the statutory requirements to become an actual eligible customer-generator. Therefore, it is not possible for legacy net metering tariff provisions to "remain in effect" at premises at which they have never taken effect.

In other words, a net metering customer must meet five statutory conditions to have legacy rights under KRS 278.466(6), the sum of which is this: the customer-generator's generating facility must actually exist and be taking net metering service at the time a retail electric supplier's first net metering compensation rate takes effect. It is clear that a customer's having merely applied for net metering service is insufficient to meet the legacy rights requirements of KRS 278.466(6).

It is equally clear that neither the Companies nor the Commission has the power to expand eligibility for the only legacy rights the General Assembly created concerning net metering. As a creature of statute, the Commission is bound to exercise only the authority the General Assembly has granted to it. [8] Here, there is no authority granted to or discretion for the Commission to exercise because the General Assembly has unambiguously defined the scope of customers to whom legacy rights apply. [9] Therefore, the Companies cannot agree that customers who have only applied for net metering service but do not have an eligible electric generating facility prior to the effective date of the proposed net metering tariffs in these proceedings may take service under Rider NMS-1.

[8] *Boone County Water and Sewer District v. Public Service Comm'n*, 949 S.W.2d 588, 591 (Ky. 1997) ("The PSC is a creature of statute and has only such powers as have been granted to it by the General Assembly.").
[9] *See, e.g., Hall v. Hospitality Resources, Inc.*, 276 S.W.3d 775, 784 (Ky. 2008) ("[I]f a statute is clear and unambiguous and expresses the legislature's intent, the statute must be applied as written. … [A]bsent an ambiguity, '[T]here is no need to resort to the rules of statutory construction in interpreting it.'")(internal citations omitted).

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Post-Hearing Request for Information
Dated May 5, 2021

Case No. 2020-00349 / Case No. 2020-00350

Question No. 40

Responding Witness: Eileen L. Saunders

Q-40. Provide the number of residential late fees waived, by month, between June 1, 2019, and February 28, 2020.

A-40. The table below provides the number of residential late fees waived due to customer requests. This does not include residential customers who receive a pledge for or notice of low income energy assistance from an authorized agency; such customers are not assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor are they assessed or required to pay a late payment charge in any of the eleven months following receipt of such pledge or notice.

	Number of Late Fees Waived	
Month	LG&E	KU
Jun-19	32	14
Jul-19	36	27
Aug-19	50	31
Sep-19	55	21
Oct-19	40	35
Nov-19	53	28
Dec-19	39	28
Jan-20	45	27
Feb-20	46	31